EFFECTS OF FISCAL SYSTEMS ON RESERVES RECOGNITION AND INVESTMENT METRICS

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<u>Certification</u>

This is to certify that the thesis titled *"Effects of Fiscal Systems of Reserves Recognition and Investment Metrics"* submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by *Ampem-Darkoh Hanson in the Department of Petroleum Engineering.*

EFFECTS OF FISCAL SYSTEMS OF RESERVES RECOGNITION AND INVESTMENT MATRICES

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ABSTRACT

Ampem-Darkoh Hanson: Effects of Fiscal Systems on Reserve Recognition and Investment Metrics

(Under The Direction of Saka Matemilola)

Petroleum reserves are affected either negatively or positively by the type of fiscal system and elements governing them. Governments, investors, policymakers, and other stakeholders have from the past been a victim of the difficulties of the reserve recognitions. This has influenced investment decisions as well as affected the attractiveness of the project. By the use of economic indicators for analysis, the host government will be able to design an efficient fiscal system and the contractor will have reliable parameters to determine the economic viability of the petroleum project. Fiscal elements such as royalty, taxes, and bonuses are linked to the variations in production parameters in order to address the mutuality of interest of the host government and contractor thereby making the fiscal system progressive. Therefore, this thesis presents research into the effects of fiscal systems on reserves recognition, estimations, and investment metrics, as well as the analysis of the progressiveness and regressiveness of the petroleum fiscal systems and their effects on reserves recognition and investment.

Keywords: *Fiscal Systems, Progressive, Regressive, Reserve Recognition, Investment Matrics*

DEDICATION

DEDICATED TO MY CHARISED PARENTS

MR. HARRISON KWABENA BOAFOH

&

MADAM BERTHA YAOTSE BOAFOH

May God Grant Them Long-life

With Good Health To Reap The

Fruit of Their Labor

ACKNOWLEDGMENT

Great is Thy faithfulness O God my Father, There is no shadow of turning with Thee, Thou changest not, Thy compassions they fail not, As Thou hast been, Thou forever will be (SDAH100). My greatest thanks go to the Almighty God for His mercies, love, guidance, and protection throughout this Thesis and my education to this far. I praise Him.

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CHAPTER ONE

INTRODUCTION

Oil and gas reserves are the most important assets to the oil and gas industries. The industry needs the sustenance of reserves to generate future cash flows when they are recovered and consequently monetized (Misund & Osmundsen, 2017). They serve as collateral upon which the industry relies on for their financial transactions, hence they represent their main source of revenues. The fiscal systems from the past years have had a significant effect on the investment in the petroleum industry. It influences production investments hence reserves recognitions. Under the concessionary system of petroleum fiscal system, the investors may be required to pay a signature bonus or a license fee to the host government (HG) to secure the concession or license. Compensations are usually through royalties and tax payments when hydrocarbons are produced. All these potentially impact investors' decision to invest because of their impact on profitability. Contractual systems in most cases are either production sharing agreements (PSA) or service contracts (SC). Under the service contracts, the Role of the IOC is essentially to provide the HG and the NOC with services and information to help the country develop its own oil resources and despite the company solely investing its own money in the exploration, it is entitled to no payment or compensation unless a viable find is made. Hence unless a viable reserve has been estimated, the IOCs decisions will be affected. This effect depends on the rate charged, specifically if the future level of the royalty is lower than the current value as it makes extracting tomorrow more attractive than commencing production today. In a production-sharing agreement between a contractor and a host government, the contractor typically bears all risks and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the chance to recover the investment from production subject to specific limits and terms. Therefore, this thesis presents research into the effects of fiscal systems on reserves recognition, estimations, and investment metrics.

1.1 STATEMENT OF PROBLEM

The distinction between when reserves and resources can or cannot be recognized under many service-type contracts may not be clear and may be highly dependent on subtle aspects of contract structure and wording. Unlike traditional agreements, the cost-recovery terms in production-sharing, risked-service, and other related contracts typically reduce the production entitlement and hence reserves obtained by a contractor in periods of high price and increase the volumes in periods of the low price. While this ensures cost recovery, the effect on investment metrics may be counterintuitive. The treatment of taxes and the accounting procedures used can also have a very significant impact on the reserves and resources recognized and production reported from these contracts.

1.2 AIM AND OBJECTIVES OF THE THESIS

The aim of this research is to do an analysis of the effects of fiscal systems on reserves recognition and investment metrics while the objectives include:

- To review reserves recognitions and estimations
- To review and describe available petroleum fiscal systems
- To review the reserves investment metrics and placement
- To review the dynamics of different petroleum reserves contract agreements

1.3 ORGANIZATION OF THE THESIS

This thesis will consist of a number of chapters, including references and appendices. Chapter one will focus on the introductory parts. This presents background information, outline the problem statement, aims, and objectives and the organization of the thesis. Chapter Two will focus on a literature review to review the works done by other researchers on the subject matter, while chapter three delineate the methodology. Chapter four will consist of data presentation, interpretation, and discussion of the findings and chapter five will present the summary, conclusions, and recommendations. References and appendices will be outlined after chapter five.

CHAPTER TWO

LITERATURE REVIEW

2.1 PETROLEUM RESOURCES AND RESERVES

Petroleum resources are all petroleum naturally occurring on or within the earth crust. They are deemed recoverable when they are commercially viable to recover with the existing technology and equipment otherwise unrecoverable. Resources become reserves when they become commercially recoverable. Petroleum reserves form an integral part and a backbone of petroleum industry.

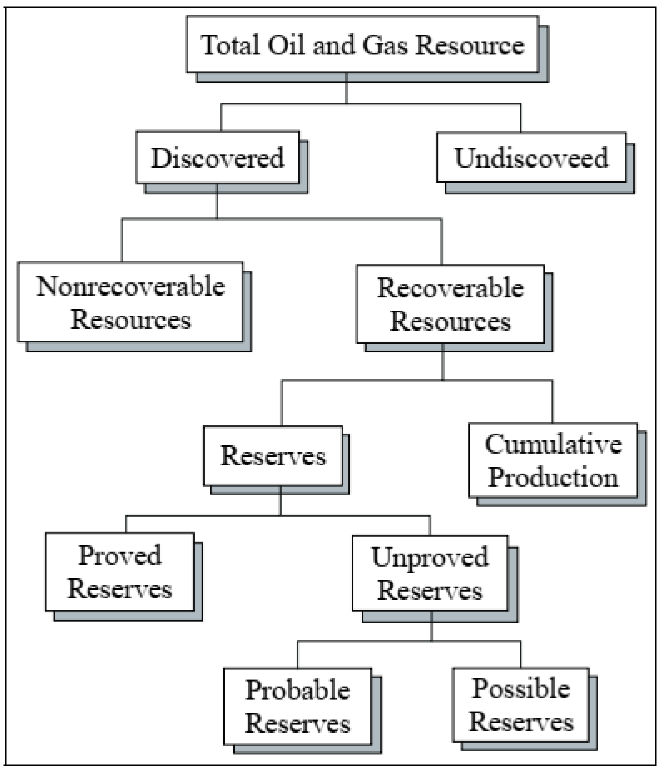


Fig. 2.1. Schematic of Petroleum Resources Classifications

2.1.1 PETROLEUM RESERVE CLASSIFICATION

Petroleum reserves are classified based on the range of uncertainty and chance of commerciality. According to PRMS, 2011, reserves are categorized as; proved reserves, probable reserves, and possible reserves.

2.1.1.1 Proved Reserves

Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with realistic certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as “Proven.”

2.1.1.2 Probable Reserves

With probable reserves, they are those additional reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

2.1.1.3 Possible Reserves

Possible Reserves, on the other hand, are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

2.2 PETROLEUM RESERVES ESTIMATION

Estimation of reserves help the industries in evaluating their revenue and the future of the industry. It is important to the oil and gas companies whose market value is influenced by estimates of their reserves, to governments with large revenues from oil and gas production and to businesses and policymakers in economics which have significant oil or gas imports or exports. Reserve estimations are done under the condition of certainty. According to Zolotukhin & Ursin, (2000), reserves can be estimated with the following approaches, namely the analogy-based approach, volumetric estimates, and performance analysis approach.

2.3 PETROLEUM FISCAL SYSTEMS

There are two basic types of petroleum fiscal systems in the petroleum industry. The fundamental differences between these systems are the ownership of petroleum resources and taxation mechanism and imposition. These systems include the concessionary system and the contractual system. The concessionary system allows private ownership of mineral resources as in the United States and Canada whiles in the contractual systems, the host government retains ownership of petroleum resources.

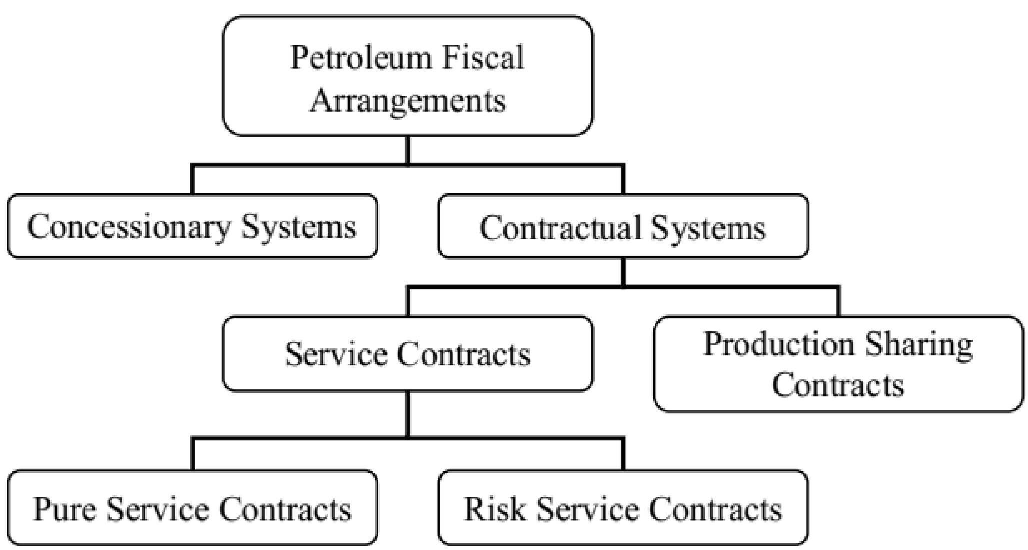


Figure 2.2 Petroleum Fiscal Arrangements

2.3.1 Concessionary

Concessionary system of petroleum fiscal system is where the state or government grants a Concession or License to an international oil company (IOC) or a consortium to get the rights for an agreed period of time to explore for and produce hydrocarbons within a licensed area or block. In order to acquire such licenses, the IOCs may be required to pay a signature bonus or a license fee to the host government to secure the Concession or License. Thereafter, the government will obtain compensation usually through royalties and tax payments when hydrocarbons are produced. The investor is typically responsible for abandonment (Tordo, 2007a), however, during expiry and terminations of concessions, title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration and production of hydrocarbons generally passes to the state (Mazeel, 2010). The company pays rentals, royalties, bonuses, and taxes based on the petroleum quantities extracted from the concession area.

2.3.1.1 Royalties

Royalties have historically been the most common method used by governments to gain revenue from the exploitation of the nation's mineral endowment. It refers to payments that are due to the host government or mineral lessor in return for the depletion of the reservoirs and the producer for having access to the petroleum resources. It is normally a percentage of the proceeds of the sale of hydrocarbon (Tordo, 2007a). It can be determined on a sliding scale, the terms of which may be negotiable or biddable, and paid in cash or in kind. The royalty represents the cost of doing business and is thus tax-deductible. Many agreements allow for the contractor to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner (PRMS, 2011). Royalties can potentially impact a company's decision to invest because of its impact on profitability. This effect depends on the rate charged, specifically if the future level of the royalty is lower than the current value as it makes extracting tomorrow more attractive than commencing production today. Royalties can also impact a company's decision to continue operations, particularly in circumstances when oil prices are too low to cover both the costs of extraction plus the royalty (Ghebremusse, 2014). This arrangement is applicable to both crude oil and to natural gas, both in concessionary and contractual license systems. The rate of royalty can be based on three distinct measures: the value of the resource extracted; the profits earned by the company; or the weight of each unit of extracted resource.

2.3.1.2 Taxes

Petroleum taxation is considered as a universal instrument adopted by the government in striking a balance between the financial interests of the oil companies and resource owners. They are governed by the specific tax laws and policies decreed in the operating jurisdiction as well as those of the home country of each company (Wright & Gallun, 2008). It is a mechanism with which the host government attempts to capture economic rent from petroleum activities worldwide (Amiesa, Omowunmi, & Joseph, 2018). These taxes may include production taxes, value-added tax (VAT), special petroleum taxes, corporate income taxes (CIT), etc. Oftentimes the government takes payment of taxes in the form of a share of production. Corporate income tax (CIT) is a percentage of the annual net incomes or profits computed after deducting eligible expenses, costs, and capital allowances. The CIT rate may be the corporate tax rate stated in the country's tax code or the upstream petroleum operations tax rate specified by the law. The Petroleum Resource Rent Tax (PRRT) is a profit-based tax which is levied on a petroleum project after all eligible outlays associated with the project, plus a threshold rate of return has been recovered and the project has yielded a predefined target return. The deductible expenditures include those related to exploration, development, operating and abandonment activities, while expenditures that are not deductible include financing costs, private override royalty payments, income tax, goods and services tax, cash bidding payments and administrative costs. The PRRT provides a fiscal regime that encourages the exploration and production of petroleum while ensuring an adequate return to the community since the project is granted a tax holiday compared with conventional tax regimes in anticipation of exceptionally high governmental returns over time. Production taxes are levied upon the owner of oil and gas interests by a state or local government and is determined from the quantity of production. Some countries like the UK, Norway, Australia, and Trinidad/Tobago have adopted special petroleum taxes. These taxes are designed to generate funds for the local government but also may contain provisions that are intended to motivate companies to explore and produce in certain areas.

2.3.1.3 Bonuses

Bonuses come in different forms; signature bonus, discovery bonus, first oil sales, production bonus. Signature bonus is a payment which is made up front to the host country for the right to develop a block commercially before work begins. This system is a widely recognized and legally accepted way for an oil company to secure the right to explore a certain field or block. Not all host countries charges for signature bonuses but may charge a minor fee for handling license applications. Bonuses are commonly paid by the investing company upon signature of an exploration and production agreement. In some cases, bonuses may be paid upon discovery, declaration of commerciality, commissioning of facilities, start of production, and/or reaching target production levels either daily or cumulative. Bonuses are easy to administer and provide an early form of revenue. The maximum level of a bonus is very much dependent on the overall fiscal terms, the characteristics of the asset, the country political risk, and the risk profile of the targeted investors. High signature bonuses may discourage risk-averse investors and affect investment decisions, especially when the political risk is perceived to be high, or when there is a high level of geological uncertainty. Commerciality bonuses are also sensitive, as they increase the economic cut-off rate of a project

2.3.2 Contractual

Under a contractual system, the investor acquires the ownership of its share of production only at the delivery point (Tordo, 2007a) in most cases either production sharing agreements or service contracts. The private companies under contractual systems have the right to receive a share of production or revenues from the sale of oil and gas in accordance with a production sharing agreement (PSA) or a service agreement (SA). The state companies either produce the oil and gas themselves or share the production and selling of it. Revenues then flow into the finance ministries' treasuries. In most contractual systems, the facilities installed by the contractor within the host government's territory become the property of the state either as soon as they are landed or upon startup or commissioning. Sometimes, the asset or a facility does not pass to the government until the expended costs have been recovered. This transfer of title for asset facilities does not apply to leased equipment or to equipment brought in by service companies (Mazeel, 2010). Furthermore, unless specific provisions have been included in the contract, or in the relevant legislation, the government is typically legally responsible for abandonment. The contractual system is classified as service contracts and production sharing contracts. The difference between them depends on whether the contractor receives compensation in cash or in crude.

2.3.2.1 Service Contracts

A service contract is a long-term contractual system that governs the relation between international oil companies (IOCs) and the host government in which the IOCs develop or explore oil or natural gas fields on behalf of the host government in return for pre-determined fees and in which in most cases the host government does not hand over the control of the extracted or subsoil or sub-surface resources to the IOCs (Ghandi & Lin, 2014). The service contracts are divided into pure service contracts and risk service contracts. The difference depends primarily on whether the fees are based upon a flat fee (pure) or profit (risk).

Pure Service Contracts

A pure-service contract is an agreement between the host government and the contractor, that typically covers a defined technical service to be provided or completed during a specific period of time. The service provided by the service company is typically limited to the value of equipment, tools, and personnel used to perform the service. The host government bears the cost of exploration and development, and the contractor is paid a fee (Mian, 2002). In most cases, the service contractor's reimbursement is fixed by the terms stipulated in the contract with little exposure to either project performance or market factors. The payment is normally based on daily or hourly rates, a fixed turnkey rate, or some other specified amount. Payments may be made at specified intervals or at the completion of the service. Payments, in some cases, may be linked to the field performance, operating cost reductions, or other important metrics. Risks of the service company under this type of contract are usually limited to non-recoverable cost overruns, losses owing to client breach of contract, default, or contract dispute. These agreements generally do not normally have exposure to production volume or market price; consequently, reserves and resources are not usually recognized under this type of agreement.

Risked Service Contracts

Under the Risked service contract, the contractor provides all the capital required for the exploration and development of petroleum resources. If the exploration and development efforts are successful, the contractor is allowed to recover its costs from the revenues generated by the sale of oil and/or gas. In addition, the contractor is paid a fee based on a percentage of the remaining revenues. Once the actual amortization period starts, the contractor must secure its payback in 5-8 years and will receive its costs plus uplift as agreed (Omowunmi O. Iledare, 2019). The fee may or may not be subject to taxes. However, if the contractor is not successful in finding oil and/or gas, all his costs of exploration are to his account with no liability to the host government (Mian, 2002).

2.3.2.2 Production Sharing Contracts

Production sharing contracts or agreements (PSCs or PSAs) give an international oil company (IOC) or consortium exploration and production rights for a fixed period of time in a defined Lease Area or Block. The IOC typically bears all risks and costs for exploration, development, and production in exchange for a share of the oil or gas produced. Production is split between the parties according to formulae in the PSC that may be fixed by statute, negotiated, or secured through competitive bidding.

If the IOC does not find a commercial discovery, there is no reimbursement of costs by the host government. The advantage to the host government of this contract system is that the government will generally receive a large share of the oil or gas. This can be sold and the revenue used according to the government's development programs and economic needs. Following the introduction of PSCs in Indonesia in the mid-1960s, they are now also used in Malaysia, India, Nigeria, Angola, Trinidad, the Central Asian Republics of the Former Soviet Union, Algeria, Egypt, Yemen, Syria, Mongolia, China, and many other countries (Mazeel, 2010). The control of the oil essentially remains with the state. National Oil companies are maintained to manage the resource whilst the contractors have execution responsibility. Contractors are required to submit a program and a budget to be approved by the national company. The type of contact system depends on the level of reserves and the political-economic aims of the host government.

It is important to note in such contracts both the level of percentage of recovery of costs and also the way in which the exploration or development costs may be recovered. In the instance that there is costs recovery before sharing of production, the contractor is allowed to recover the costs out of net revenues. The costs recovery limit is the sole true distinction between concessionary systems and PSCs. After royalty and cost recovery, the amount of revenues remaining is termed profit oil or profit gas. This is the equivalent of taxable income in a concessionary system and would be termed as service fee within the service agreement.

2.4 INVESTMENT IN UPSTREAM PETROLEUM PROJECTS

2.4.0 Introduction

The fundamental assets of producing companies and host countries are oil and gas reserves and resources; hence, before any company undertakes any petroleum project, there must be the opportunity to report reserves (Elliott Dixon Young, 2012). The major objective of the upstream petroleum industry is the ability to explore, develop and produce hydrocarbon economically. Zealous competition and scrutiny by the investment companies and instability in oil prices drive oil companies to search for more attractive and sustainable exploration and producing project opportunities that will yield the greatest rate of return for a given investment (E.D. Young & McMichael, 1998). Consequently, petroleum contracts and agreements for these opportunities have become increasingly complex, and again increasing the focus on the ability to recognize reserves and resources. For mutual gain between the host government and the contractor, various fiscal systems such as production-sharing and other nontraditional fiscal agreements have been developed to provide the flexibility for the host governments to streamline the fiscal terms to fit their sovereign needs while allowing the contractors to redeem their costs and attain a desired rate of return. Nevertheless, the revenues from the fiscal arrangements are subject to various fiscal arrangement terms such as royalties and/or royalty payments, profit sharing, taxes, and cost recovery. These fiscal arrangement terms significantly impact the ability to recognize and report hydrocarbon reserves.

2.4.1 What Influences Investment Decisions

A project might, for instance, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with common ownership (PRMS, 2011). A project represents the link between petroleum accumulation and the decision-making process, including budget allocation. Petroleum projects are very risky and cost intensive. They require a huge sum of capital to startup and there is high uncertainty regarding profitability and return on investments. Investment decisions regarding petroleum business require the considerations of many factors. This includes the total funds available to start up, the cost of the specific investment and the expected rate of return on that investment.

The high risk and uncertainty associated with the business also lead to the analysis of various parameters before investment. Before an International Oil Company (IOCs) invest or start a petroleum project, they look out for concessions that have larger proved reserves or they consider the fiscal systems that allow recognition of petroleum reserves, in order to make the investment profitable in the long run. Banks, investors, and other firms will only invest in a petroleum business which is sustainable. Sustainability of the petroleum project is determined by the size of the proved reserves, the certainty of the recovery factor and the possibility to report and recognize reserves.

2.4.2 Reserves and Resources Recognition

For reserves and resources to be recognized and reported in a country, there are national regulatory bodies that have been established to provide standards, which outline vivid descriptions of the categories of reserves to be reported, the needed guidelines to follow, and the format for reporting the oil and gas reserves and resources. In most cases, these standards and regulations are limited in providing considerable guidance on the type of fiscal arrangements that give a company the entitlements to reserves and resources reporting.

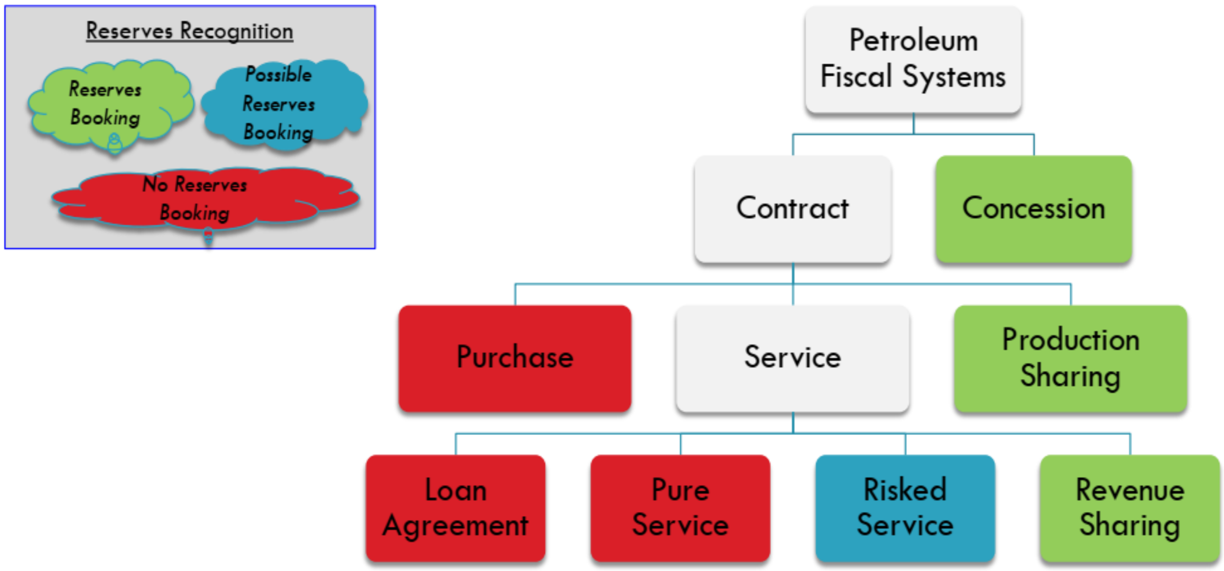


Figure 2.3 Classification of Petroleum Fiscal Systems & Reserve Recognition (Matemilola, 2016)

According to (PRMS, 2011), the concept of economic interest is the basis for recognizing and reporting reserves and resources. Many companies refer to SEC Section S-X, Rule 4-10b, "Successful Efforts Method" (US SEC 1993) to determine when an economic interest exists. The primary focus of US SEC 1993 regulation is on the US financial reporting for oil and gas producing activities and it entails a key definition for a mineral interest that gives a suitable framework and standards for establishing when an interest in a property exists and guidance on when reserves and resources can be recognized.

Regulation SEC Section S-X, Rule 4-10b can be summarized into elements that support and establish an economic interest and the ability to recognize reserves and resources (PRMS, 2011). These include the right to extract oil or gas, the right to take produced volumes in kind or share in the proceeds from their sale, the exposure to market risk and technical risk, and the opportunity for a reward through participation in producing activities. Apart from supporting the economic interest to recognize and report reserves and resources, the regulations also establish specific elements that prevent the recognition of reserves and resources. These include the participation that is limited only to the right to purchase volumes, supply or brokerage arrangements, and agreements for services or funding that do not contain aspects of risk and reward or convey an interest in the minerals

2.4.3 Effects of Petroleum Fiscal Systems on Reserves and Resources Recognition and Reporting

The petroleum fiscal systems have agreements and contract terms established by the host government to achieve ultimate revenues from the country's petroleum resources. However, these fiscal systems do not have a well-defined approach or practices of determining when and how to recognize and book petroleum reserves and resources. The concessionary, Production sharing, revenue sharing and Risked service are the forms of fiscal systems that allows booking of petroleum reserves. In light of that, most investors look out for fiscal systems that allow booking and recognizing of reserves to invest with. These fiscal systems also have their peculiar conditions and terms they are governed with. Reserve booking is a factor in the sustainability of petroleum investment. Figure 1 shows the fiscal systems that allow and do not allow reserve booking and recognition.

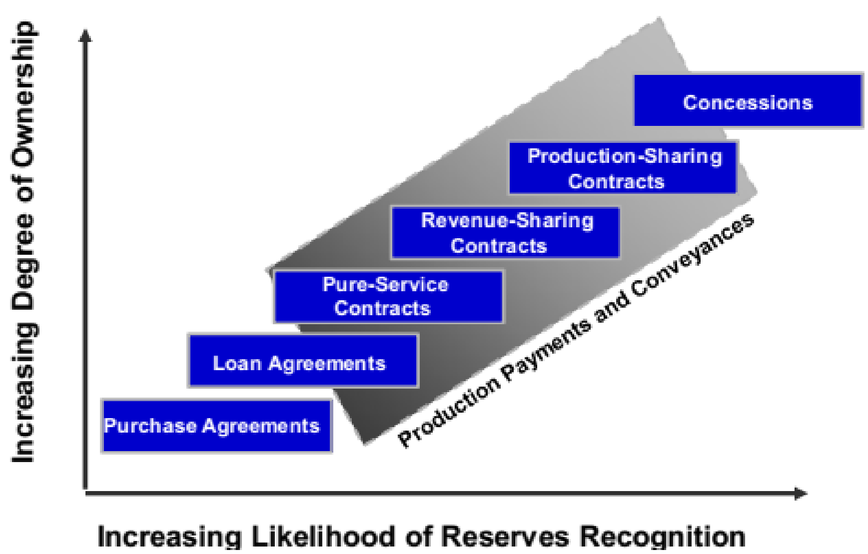


Figure 2.4 Spectrum of Petroleum Fiscal Systems (Elliott Dixon Young, 2012)

In fostering the recognition and booking of petroleum reserves and resources under the petroleum fiscal systems, much emphasis has to be laid on specific elements of the fiscal terms that enhance recognition of reserves and resources. (Johnston, 1994), proposed the classification system template for petroleum fiscal systems. (McMichael & Young, 1997), expanded this template to include three additional types of agreements: purchase agreements, loan agreements, and production payments and conveyances. The ranking of the expanded template in terms of their ability to recognize reserves and resources and report them to regulatory agencies is shown in Figure 2.4. Table 2.1 shows a summary of the key aspects of each type of agreements. The petroleum fiscal systems with regards to reserves recognitions are elaborated below;

CONTRACT TYPE	OWNERSHIP	PAYMENT	RESERVES
Concession	Contractor	In-Kind	Yes
Production Share	Contractor (When Produced)	In-Kind	Yes
Revenue Share	Government	Share of Revenue	Yes
Risked Service	Government	Fee-Based	Likely
Conveyance	Government	Production Pmnt	Likely
Pure Service	Government	Fee-Based	No
Purchase Contract	Government	Product Cost	No
Loan Agreement	Government	Interest	No

Table 2.1 Contract Summary

2.4.3.1 Concessionary System

Under the concessionary system, the contractor or the international oil company (IOC) is given the right by the concession owner or the host government for an agreed period of time to explore, produce and market oil and gas within a predetermined area at their own risk and expense. The company holds title to all resources produced for the period when the agreement is in effect and they pay rentals, royalties, bonuses, and taxes based on the petroleum quantities extracted from the leased area. Reserves consistent with the net working interest that can be recovered during the term of the agreement are typically recognized by the upstream contractor (Elliott Dixon Young, 2012). In addition, if the contract contains provisions for an extension and there are high possibilities of extending the contracts, then additional reserves are likely to be recognized for the length of the extension period, provided the necessary conditions are satisfied.

2.4.3.2 Production Sharing Agreement

Production sharing contracts or agreement exist between a host government and a contractor. With this kind of arrangement, the contractor bears all the risks and cost for exploration, development, and production. However, if the exploration is successful, the contractor recovers the cost of investments from the production (cost hydrocarbons), according to the limits and terms of the arrangement. The contractor also receives an agreed share of the production remaining after cost recovery (profit hydrocarbons). The ownership of the petroleum resource is retained with the Host government, while the contractor receives title to the prescribed share of the volumes as they are produced. Resources may also be recognized for future development phases where project maturity is not sufficiently advanced or for possible extensions to the contract term where this would not be a matter of course. Contractor’s entitlement to production reduces as the price of petroleum increases, as a smaller share of production is required to recover investment costs and profit. Figure 2.5 shows a schematic indicating the distribution of yearly project production between the contractor and the host government.

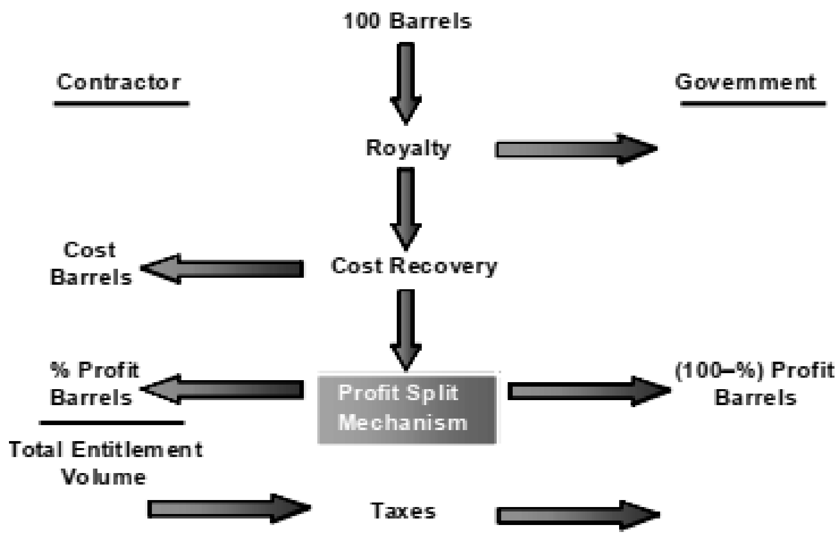


Figure 2.5 Illustration of Production-Sharing Contract (Elliott Dixon Young, 2012)

2.4.3.3 Revenue-Sharing Contract

Revenue-sharing contracts are similar to the production-sharing contracts where capital and technical expertise are provided by the contractor for the exploration and development of petroleum resources. In the same way, if the exploration efforts are successful, the contractor recovers the cost from sales revenue, rather than production. However, if exploration efforts are unsuccessful, the contractor bears the losses alone. Figure 2.6 is a schematic indicating the distribution of yearly project production between the contractor and the host government.

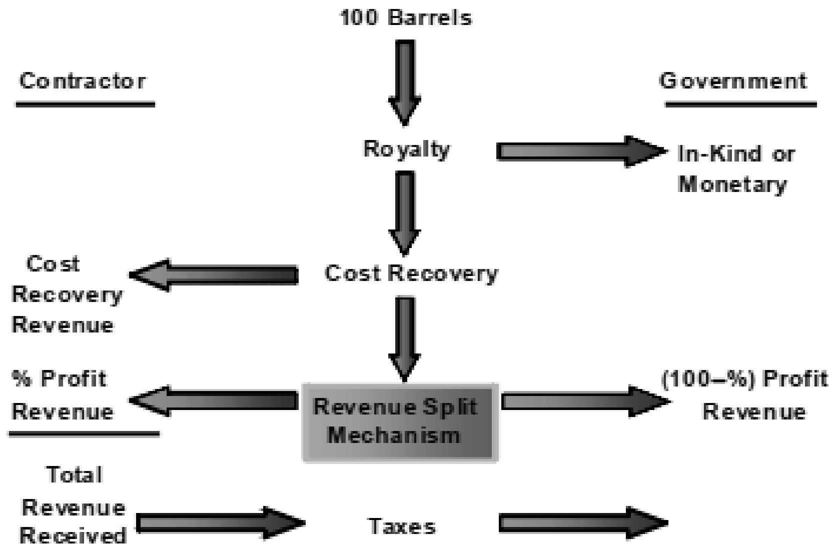


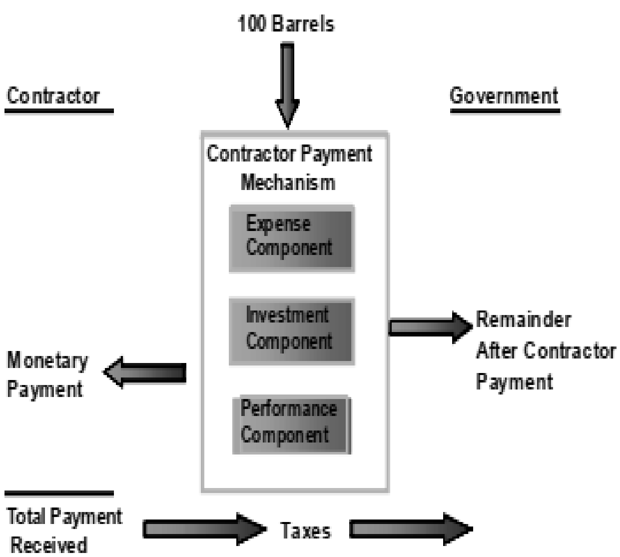
Figure 2.6 Illustration of Revenue-Sharing Contract (Elliott Dixon Young, 2012)

2.4.3.4 Risked-Service Contracts

Under the Risked service contract, the contractor provides all the capital required for the exploration and development of petroleum resources. If the exploration and development efforts are successful, the contractor is allowed to recover its costs from the revenues generated by the sale of oil and/or gas. In addition, the contractor is paid a fee based on a percentage of the remaining revenues rather than a share of the production. When a contractor has an economic or revenue interest in the production, reserves and resources can be recognized. Again, resources may be recognized for future development phases or possible extensions to the contract terms. The reserves and resources equivalent to the value of the cost-recovery-plus-revenue-profit split are normally reported by the contractor depending on the specific contractual terms.

2.4.3.5 Pure-Service Contracts

A pure-service contract is an agreement between a contractor and a host government that typically covers a defined scope of technical service to be provided or completed during a specific period of time. The investment by Service Company is typically limited to the value of equipment, tools, and personnel used to perform the service, with little or no exposure to either project, production or market risks. Payment for services rendered is normally based on daily rates, hourly rates or some other specified amount for a specified interval or after the completion of the service. In some cases, payments may be tied to the field performance, operating cost reductions, or other important metrics. In many cases, payments are made from government general revenue accounts to avoid a direct linkage with field operations. Risks of the service company under this type of contract are usually limited to non-recoverable cost overruns, losses owing to client breach of contract, default, or contract dispute. The service company may, however, have an obligation to report gross (total working interest basis) reserves and resources to the host countries' regulatory agencies. Figure 2.7a is a schematic of the distribution of yearly project revenue between contractor and government.



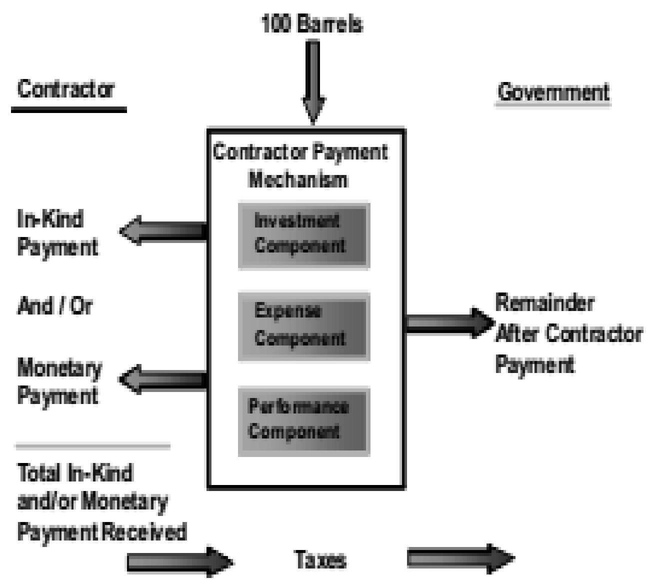


Figure 2.7a Example Pure-Service Contract (Elliott Dixon Young, 2012)

Figure 2.7b Example Risked-Service Contract (Elliott Dixon Young, 2012)

2.4.3.6 Loan Agreements.

A loan agreement is the agreement system in which all or part of the petroleum project is financed by either a bank, partner or other financial investors. The funds are compensated by the specified interest rate from the agreement between the borrower and the lender. The lender does not participate in profits earned from the project above this interest rate. Repayment of investment is followed on a fixed repayment schedule, also, repayment of the obligation is usually made before any return to equity investors. The borrower bears all the risk. Compositions of funds are not affected by variations in production, sales and market prices. Reserves and resources would not be recognized by the lender under this type of agreement

2.4.3.7 Carried Interests.

Carried interest is an arrangement in an oil and gas industry whereby one party (the carrying party) agrees to defray all costs of drilling, developing, and operating the property costs of another party (the carried party) on a jointly owned license. This arises when the carried party is either loath to bear the risk of exploration or is unable to fund the cost of exploration or development directly (Elliott Dixon Young, 2012). If the project is successful, the carrying party keeps all of the working interest's earnings from selling the production and pays all of the operating expenses. The carrying party is entitled to keep the carried party's share of net profit until the carrying party has recovered the carried party's share of drilling and completion costs, (which was paid by the carrying party), addition to any applicable penalty (Wright & Gallun, 2008). After the carrying party has recovered his expenses, the carried party resumes its role as a regular working interest partner in the operation at the point at which payout is reached. The carrying party normally recognizes the additional production received. If project maturity is not sufficient to classify the amounts as reserves, the PRMS resources categories would be used according to the agreed reimbursement terms (PRMS, 2011).

2.4.3.8 Purchase Contracts.

The purchase contract is an agreement which provides the buyer the right to purchase a specified volume of petroleum at an agreed price for a defined period. All the risks from the project, production and market prices are borne by the seller under this type of contract arrangement. The purchase contract can provide long-term access to reserves and resources through production, however, the buyer does not have the rights to extract, nor interest in the reserves. This is typical of gas-supply contracts. Subsequently, reserves and resources would not be recognized under this type of agreement (Elliott Dixon Young, 2012).

2.4.3.9 Production Payments and Conveyances

Production Payments and Conveyances have features of property trades, loans, and production purchase contracts whereby assets are transferred between partakers, assets are jointed, or loans are provided in return for the right to purchase volumes. Reserves and resources may be recognized by the purchaser of the production payment at certain instances. Fig. 6 gives an illustration of a typical conveyance.

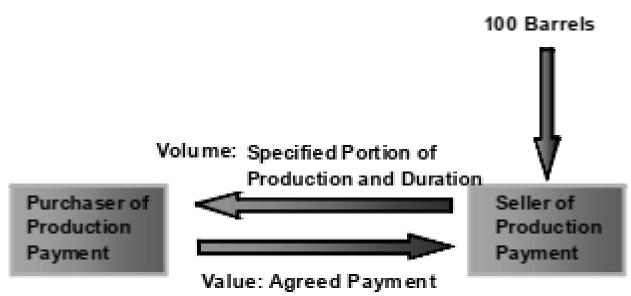


Figure 2.8 Example Conveyance and Production Payment (Elliott Dixon Young, 2012)

2.5 PROGRESSIVE AND REGRESSIVE FISCAL SYSTEMS

In every petroleum business, the final cash flow is distributed between the government and the contractor. The portion of the cash flow which ends up in the hands of the government is the government take and the remaining portion of the cash flow which finally gets to the contractor is the contractor take. Hence the sum of the government take and the contractor take will make up the total cash flow of the project**.**

Progressive fiscal system regime is the regime where when the project profitability increases the government takes as a percentage goes up and the contractor take will naturally fall down. For example; if the initial government take is 60% of the production and that of the contractor take is 40%, as the project profitability increases, the government take increases from the initial percentage of 60% to let say 70% and consequently, the contractor take as a percentage will fall from the initial value of 40% to 30%. The regressive fiscal system, on the other hand, is the reverse of the progressive fiscal system. As the profitability of the project increases, the government take as a percentage will fall down, while the contractor take as a percentage will go up.

This is due to the direct consequences in which fiscal systems are loaded. It is better a fiscal system is either front end loaded or back end loaded with respect to government take. This is whether the components that constitute the government take comes in at the very beginning of the project or before the project has generated positive cash flow or has generated profit or whether those elements start to kick in after the project has generated cash flow or profit. Examples of front end loaded elements are a signature bonus, production bonus or royalty. This is because they start to kick in at the beginning of the project whereas elements like a share of profit oil, tax based on profit are back end loaded because they start to come in at the later part of the cash flow and they make the fiscal system progressive.

The main aim of designing any fiscal system is to have a framework which will honor the mutuality of concern of the government and the contractor. The system should be made flexible in order to give many incentives to the contractor both in a good project and not a good project thus when the project is marginal economical, the contractor should have an annual return on his investment which justifies his investment and if the project becomes very profitable, thus instances where there is high oil prices or huge reserves discoveries, in that case, the contractor should still have a good chunk of cash flow, however most should be go to the government. A system like this addresses the mutual concerns of both the government and the contractor.

2.6 THE WORLD ENERGY MARKET

The recognized instability of oil prices has led to the development of oil futures markets and the trading of financial derivatives (Albinali & Dahl, 2014). The World Energy market is not just a network of suppliers and buyers because oil can and does move so freely from one area to another across the globe, so it is better to think of the oil market as a global pool. Factors affecting the evolutionary changes in the global petroleum market include; Innovation and Technology, Mergers and acquisitions, Emerging economies specifically China and India and Industry substitutes and alternative fuels (Omowunmi O. Iledare, 2019). The fluctuations of oil prices have significantly resulted in creating high uncertainty in the oil and gas companies. Investment decisions are made based on the knowledge of some factors and the oil price which is eventually a major determinate of profitability. It is a challenge to make effective investment decisions when tomorrow prices fall up to $10 Bbl, and the next day jumps to a record high level of $130 Bbl (Kolbikov, Kolbikova, & Sholudko, 2014). These unstable conditions have significantly affected investment matrixes and reserves recognitions.

CHAPTER THREE

METHODOLOGY

3.1 PROGRESSIVE AND REGRESSIVE FISCAL SYSTEMS AND ELEMENTS

3.1.1 Introduction

To attract investors to an oil and gas region, an area must not solely be highly prospective in the geologic sense, but the area must as well have a dynamic, efficient, and stable fiscal arrangement (Iledare, 2014). This fiscal system should enhance the mutual interest of the petroleum project thereby enable the host government to capture maximum revenues as desired and the contractor getting maximum return on his investments. The primary aim of the host government has to be to capture maximum revenues from a petroleum project through various levies, taxes, royalties, and bonuses; and at the same time, to attract foreign investors. He also seeks to have developmental and socioeconomic objectives such as efficient resource development, job creation, transfer of technology, development of local infrastructure, and sustainable economic growth. Oil companies tend to view host countries' fiscal regimes critically on the basis of their financial objectives (Iledare, 2014). They aim to achieve a return on investment that meets the shareholders' expectations and the corporation's objectives. They ensure that they have long term growth in income, have access to reserves and reserves replacements, and their achievements are consistent with the risks associated with the projects.

3.1.2 Progressive and Regressive Fiscal Systems

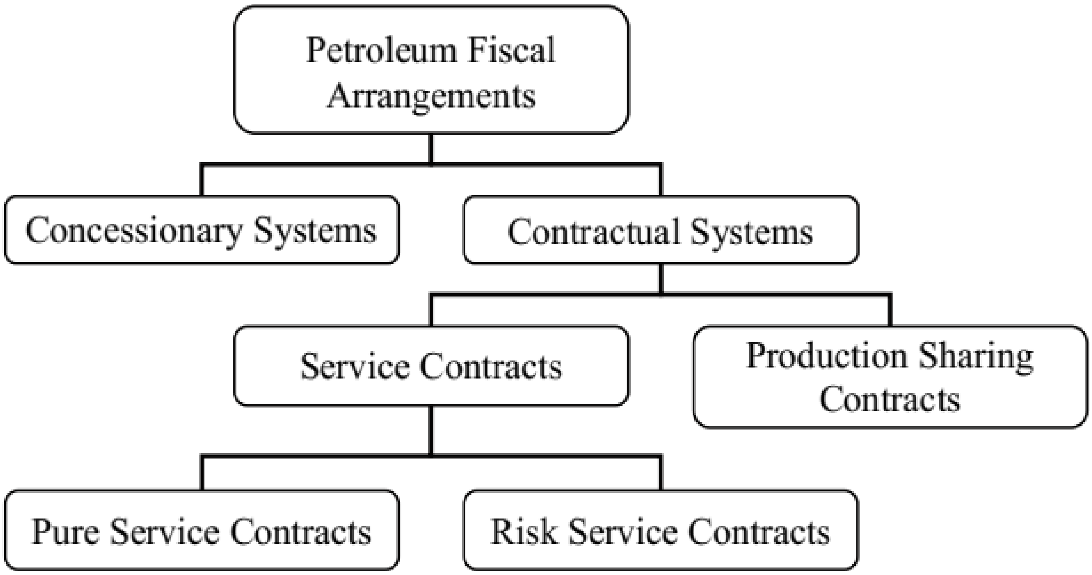


Figure 3.1 Petroleum Fiscal Systems

3.1.2.1 Concessionary Fiscal System

The concessionary fiscal system is one of the oldest practiced fiscal systems in the world. They typically compose of a fixed royalty and fixed tax payment made to the Host government by the contractor. Royalty paid to the Host government is a percentage of the gross revenue, without accounting for any cost recovery, however, some countries make provisions for the deduction of processing costs before royalty calculations. The cost recovery which consists of the contractor's costs, depreciation, loss carried forward and sometimes depletion allowance is then deducted from the remaining portion of the gross revenue after the royalty payment. This becomes the taxable income and is subsequently taxed according to the terms of the agreement. The concessionary system becomes regressive fiscal system because of the fixed royalty and tax components since many economically viable projects eventually become uneconomical to the contractor after the payment of royalty to the host government. To address these shortcomings, the fixed royalty and tax system are replaced with a sliding scale royalty and tax system. This will make the fiscal system progressive since the royalty and tax rates vary from prospect to prospect and country to country. Royalties as high as 25% and tax rates as high as 85% are very common (Tordo, 2007b). The taxes may consist of different dimensions, these include economic rent tax (ERT) or export tax, which may be deducted from the gross or net revenue to yield taxable income. The taxable income is subject to corporate income tax. Some systems will also have a third tier of taxation called excess profit tax (EPT) or windfall profit tax (WPT) (Mian, 2010).

3.1.2.2 Production Sharing Contracts (PSCs)

Production-sharing systems are commonly practiced now than the concessionary fiscal system. The PSCs may also include royalty and tax payments but the main sharing is based on the profit sharing concept (Mian, 2010). Some of the contract terms are fixed whiles others might be negotiated between the host government and the contractor. The net revenue after royalty payment is split into cost recovery oil and profit oil. The cost recovery oil is used by the contractor to recover all the recoverable expenses incurred while the profit oil is again split between the host government and the contractor based on the agreed terms in the PSC. The contractor's share of the profit oil is subject to tax. The coverable cost maybe subjected to cost recovery limit, which is a percentage of the cost that can be recovered in a particular period and the remaining (carried forward cost) are recovered in the subsequent years until all the cost is fully recovered. However, if there is excess from the cost recovery oil, which is also known as excess cost recovery (ECR), it is split between the host government and the contractor. The costs to be recovered by the contractor are referred to as petroleum costs. To make the system progressive, the bonuses, royalty, cost recovery, profit oil, excess recovery oil, and taxes rates should be a tie to conditions such as daily production, cumulative production, oil price, water depth, etc., in the fiscal systems. The cost recovery may be high in the beginning since there will be a large cost to recover with a high payback period once the contractor breaks even, then the cost recovery percentages will automatically be reduced and the profit oil, ECR, and/or taxation percentage, will increase.

3.1.2.3 Risked Service Contracts

With Risk Service Contracts, the ownership and all production belongs to the host government. The contractor provides all capital associated with exploration and development of petroleum resources and if exploration is successful, the contractor is allowed to recover costs through sale of the oil or gas. The host government pays the contractor a fee based on a percentage of the remaining revenues after recovering the cost however, this fee is subject to taxations. The contractor may also be given preferential rights to purchase production from the government. This fiscal system is progressive nature since the contractor does not have to pay royalties before arriving at the profit oil. Also, the share of the contractor is linked to profit oil, and as the profit increases, both the host government and the contractor takes increase, and vice versa. The regressiveness of this fiscal systems occurs when the percentage of the remaining revenue entitled to the contractor is very low and subsequently makes the project uneconomical.

3.1.2.4 Pure Service Contracts

Pure service contracts are quite rare and are practiced where the host government has substantial capital but seeks for technical expertise. A contractor is therefore contracted to carry out exploration and/or development works on behalf of the host government for a fee for performing a service. No exploration risk is borne by the contractor but all risk is borne by the host government. This type of contracts are commonly used in the Middle East and examples exist in Saudi Arabia, Iran, Kuwait, and the Philippines. Examples of such contracts are placed for drilling services, development services and some exploration services such as Halliburton and Schlumberger where the contractor is paid a fee for performing a service. This fiscal system becomes progressive to the host government when the return on investment is high. The contractor fee is fixed and is not affected by high and low return on investment.

3.2 PROGRESSIVE AND REGRESSIVE NATURE OF PETROLEUM FISCAL ELEMENTS

In as much as the host government (HG) wants to capture more revenue from the country's petroleum resources, the contractor (investor) also seeks for a high return on the investment. Petroleum Fiscal systems have been the connection between the HG and the contractor, and their elements determine how lucrative the project will be to both parties. To have progressive petroleum fiscal systems, fiscal elements such as royalty, bonus, tax rates, cost recovery limits, profit oil split, and uplifts must be subject to sliding scales. These elements can be a tie to production rates, water depth, cumulative production, oil prices, R-Factors, age and depth of reservoirs, remote locations, history, onshore or offshore.

3.2.1 Royalty

Royalty is the percentage of gross or net revenue, free of expense, received in cash or in kind, and it is tax deductible in oil and gas tax calculations. Economic rents earned from royalty payments are usually not based on profits and this dampens the progressiveness of a fiscal regime and would normally have effects on investments and resource development economics (Echendu, 2015). The common types of royalties used in petroleum fiscal systems include; Fixed percentage royalty, fixed payment royalty, and Graduated royalty rates, which could be jumping graduated royalty rate or linear sliding scale royalty rate.

3.2.1.1 Fixed percentage royalty

Fixed percentage royalty is the most commonly used. With this kind of royalty, a fixed percentage of the gross revenue is either paid in cash or in kind to the mineral owner, in most cases, the host government. According to the contract terms, it is mostly independent of oil price and project expenses. It is not commonly in use as it was in the past (Omowunmi O. Iledare, 2019). Examples of countries that use fixed percentage royalty are Congo, Gabon, Ghana, Malaysia, United States, and Venezuela. For example, if the gross revenue for a petroleum project is 100 BOPD, the current oil price is US55 per BBL and the fixed royalty rate is 15%, then, Royalty (in kind) = 15% x 100 BOPD = 15 BOPD, or

Royalty (in cash) = 15% x 100 BOPD x US$55 / BBL = US$ 825.

This type of royalty is a lump sum payment and is not tie to the profit but the gross revenue, this increases the government take and reduces the contractor thereby making the system regressive.

EXAMPLES OF FIXED PERCENTAGE ROYALTY RATES	
Country	**Fixed Royalty Rate**
Indonesia & Philippines	0.00%
Papua New Guinea	2.00%
Greenland	5.00%
Gabon, Malaysia, Yemen	10.00%
Argentina	12.00%
Benin, Ghana, Namibia, Federal US	12.50%
Congo, South Korea, Mozambique	15.00%
Venezuela, the US offshore	16.67%
Bolivia	18.00%
Oklahoma	18.75%
Colombia, Neutral Zone, Tanzania	20.00%
Offshore Texas state waters	25.00%

Table 3.1 Example of Fixed Percentage Royalty Rates of Some Countries

3.2.1.2 Fixed Payment Royalty

With Fixed Payment Royalty, whether profit is made or not, a fixed payment/amount is paid to the lease owner according to the contract terms. For example, if the royalty payment agreed is 100 BOPD and the gross revenue generated is 150 BOPD, the landowner is entitled to the agreed 100 BOPD. This type of royalty is regressive in nature because when the revenue increases, the contractor makes more profit while the take of the landowner is fixed. However, fixed payment royalty is no longer commonly in use.

3.2.1.3 Graduated Royalty Rate

Graduated Royalty Rate turns to enhance the mutuality of interest between the host government and the contractor. It is used to capture the uncertainties in field size, oil price, average daily production, geology, economics or engineering, in order to exploit potential increases in both reserves and production. The scales can be tied to R-factor, well productivity, field production, cumulative production, well production, oil price, water depth or oil quality and project economic measures. Graduated Royalty Rate could be jumping graduated royalty rate or linear sliding scale royalty rate.

EXAMPLES OF GRADUATED ROYALTY RATES					
Country	Royalty Rate	Production Rate	Country	Royalty Rate	Water Depth (m)
Abu Dhabi	12.50%	≤ 100 MBOPD	Nigeria (PIB)	16.67%	≤ 200 m
	16.00%	100 - 200 MBOPD		12.00%	200 - 500 m
	20.00%	200 + MBOPD		8.00%	500 - 800 m
				4.00%	800 - 1000 m
Cameroon	2.00%	≤ 1.0 MBOPD		0.00%	> 1000 m
	6.00%	7.7 MBOPD			
	9.00%	13.4 MBOPD	US Gulf Coast		
	11.00%	19.0 MBOPD		16.70%	0-200 m
	12.50%	>19.00 MBOPD	≤ 17.5 MMBOE	16.70%	200 - 400 m
			≤ 52.5 MMBOE	12.50%	400 -800 m
Gabon	5.00%	≤ 10 MBOPD	≤ 87.5 MMBOE	16.70%	≥ 800 m
	10.00%	10 - 20 MBOPD			
	15.00%	20 - 40 MBOPD			
	20.00%	> 40 MBOPD			

Table 3.2 Examples of Graduated Royalty Rates of Some Countries

With jumping graduated royalty rate, the royalty rate is based on the tranche specified (reached) and it is applied to the total volume of the gross oil revenue, while with Linear sliding scale Royalty Rate, there are different royalty rates for different tranches of the revenue of the oil of different tranches of production. So the first tranche of production will have a different royalty rate and the next level of production will attract a different level of royalty rate and if there is a third level of production, it will attract a different royalty rate different from the first and second. So different volume will attract a different level of royalty rates.

For example, if a contractor produces 50 MBOPD in a year, the royalty calculation using Gabon royalty scale from Table 3.2, sliding and jumping royalties calculations are illustrated in Table 3.3 below.

ROYALTY SLIDING SCALE	**LINEAR SLIDING SCALE ROYALTY RATE**	**JUMPING GRADUATED ROYALTY RATE**
Gabon Royalty Scale		
	First 10 MBOPD	
5% ≤ 10 MBOPD	= 5% × 10MBOPD = 0.5 MBOPD	For the production rate of 50MBOPD
	Next 10 MBOPD	
10% 10-20 MBOPD	= 10% × 10MBOPD = 1.0 MBOPD	Royalty = 20% × 50MBOPD
	Next 20 MBOPD	
15% 20-40 MBOPD	= 15% × 20MBOPD = 3.0 MBOPD	= 10 MBOPD
	Next 10 MBOPD	
20% > 40 MBOPD	=20% × 10MBOPD = 2.0 MBOPD	TOTAL ROYALTY = 10 MBOPD
	TOTAL ROYALTY = 6.50 MBOPD	TOTAL ROYALTY = 10 MBOPD

Table 3.3 Sliding and Jumping Royalties Calculations

From the above calculations, the sliding royalty rate is more progressive than the jumping, since the royalty payment is linked to production, hence the contractor will pay less royalty when the production is low and pay higher when the production increases. Also, the profit oil increases with an increase in production, consequently, an increase in revenue to both HG and contractor.

3.2.2 Taxes

The petroleum industry in most countries are bounded by the standard income taxes and may have additional higher tax rates such as production taxes, value-added tax (VAT), special petroleum taxes, corporate income taxes (CIT), Crypto taxes, Petroleum Resource Rent Tax (PRRT), etc., to capture more rent. In most cases, taxes are only due when annual revenue exceeds some measure of costs and allowances. With a fixed tax rate, corporate taxes are relatively regressive, as their burden in percentage terms remains the same at different levels of profitability. To ensure that the host government shares the upside if a project becomes very profitable, more and more countries have adopted progressive income tax rates. This is done by using stepped tax rates linked to parameters like the crude oil price, the volume of production, the sales value, and so on. These are “add-on” to conventional proportional income tax. In some countries, the investor’s income tax is paid by the government out of its share of production. Because corporate income taxes are well defined in the country’s tax code, their assessment, collection, and monitoring can be more easily accommodated within the country’s existing systems, thus lowering the government’s administrative burden. Progressive income taxes tie the level of taxation to parameters that are linked to the level, activity or the price of crude oil or gas. This allows the host government to partake in the project’s upsides when economic conditions are more favorable. The parameters normally used to determine the progressive rates of income tax are not necessarily fully correlated with the investors’ return on investment. Hence this type of corporate tax might not be neutral for investment decisions.

3.2.3 Bonuses

Bonuses are single lump payments made by the contractor to the host government or the lease owner during a particular phase of the project. Bonuses are generally not recoverable costs and they become a cost to the contractor but revenue to the host government. High bonuses charged make the fiscal system regressive and less attractive. A country's fiscal system must be designed with progressive bonus structures where the mineral owner recovers maximum revenue as well as the investor getting maximum return on investment. Common bonuses used include signature bonus, Discovery bonus, Production bonus, and other bonuses which are contained in the fiscal systems.

3.2.3.1 Signature Bonus

Signature bonus is a onetime fee, paid by the contractor to the host government when a lease is granted in order to secure the right to explore and develop a block or a lease. Signature bonuses may be determined in three different ways which are; through bidding, through negotiation, and by legislation. This payment is not affected by the economic success of the concession or production. Example of Signature Bonus in the Nigeria PSC 2005 is given in Table 3.4 below;

TERRAIN	**BONUS**
Frontier	\$0.5 million
Onshore	\$5 million
Shelf	\$5 - 10 million
Deep-water	\$50 million

Table 3.4 Signature Bonus of Nigeria PSC 2005

3.2.3.2 Production Bonus

Production bonuses are paid when production from a given lease or block reaches a specified target. It provides future revenue for the government at various level of production or discovery. It may be required when petroleum is discovered (Discovery Bonus), when development begins, at the start of production, whenever certain predetermined levels of production are reached, and/or at a certain level of cumulative production (Omowunmi O. Iledare, 2019). For example, the contractor may pay $3 million when the production from the block reaches 20,000 STB/D and another $3 million when the production reaches 40,000 STB/D, and so on. Production bonuses may also be tied to cumulative production. For instance, $3 million may be paid when 10 million barrels are produced and another $3 million may be paid when the cumulative production reaches 20 million barrels. Examples of production bonuses of some countries are listed in Table 3.5 below.

EXAMPLES OF PRODUCTION BONUSES OF SOME COUNTRIES					
Country	Production Level	Production Bonus	Country	Production Level	Production Bonus
Vietnam	Discovery	$2.5 million	Albania	25,000 BOPD	$1.0 million
(July, 1991)	50,000 BOPD	$2.5 million	(Circa 1991)	50,000 BOPD	$1.0 million
	100,000 BOPD	$3.5 million			
	150,000 BOPD	$4.0 million	Bangladesh 1989	5,000 BOPD	$0.5 million
				10,000 BOPD	$1.0 million
Myanmar	Discovery	$1.0 million		15,000 BOPD	$1.5 million
(1989/1990)	10,000 BOPD	$2.0 million		20,000 BOPD	$2.0 million
	30,000 BOPD	$3.0 million			
	50,000 BOPD	$4.0 million	Egypt	30,000 BOPD	$3.0 million
			(1986 Standard Model)	50,000 BOPD	$5.0 million
Gabon	Startup	$1.0 million		100,000 BOPD	$7.0 million
(PSC, 1989)	10,000 BOPD	$1.0 million			
	20,000 BOPD	$2.0 million	Malaysia 1994		No

Table 3.5 Examples of Production Bonuses of Some Countries

3.2.4 Technical Cost

Total technical cost consists of capital expenditure (CAPEX) and operating expenses (OPEX).

3.2.4.1 Capital Expenditure (CAPEX)

Capital Expenditure (CAPEX) are also referred to as front-end costs. They are usually large expenditures incurred, often several years before any revenue is obtained. CAPEX consists of Geological and Geophysical costs, drilling costs, well development cost, surface equipment cost, etc. CAPEX can be classified as either tangible or intangible costs. Tangible Costs are costs incurred from tangible properties and are capitalized and depreciated for after-tax calculation purposes while intangible costs are incurred from intangible properties and are amortized for tax calculation purposes.

3.2.4.2 Operating Expenses (OPEX)

Operating expenses are also referred to as Lease Operating Expenditure (LOE). These are direct costs that are associated with production and injection, incurred in day-to-day operations and benefit only the period in which they are made. OPEX typically consists of fixed OPEX and variable OPEX. Fixed OPEX consists of management fees, rents, etc. while variable cost consists of the cost of raw materials, feedstock, maintenance cost, utilities, manpower, payroll, inventory costs, etc.

3.2.4.3 Depreciation

Depreciation is non-cash expenses usually associated with the acquisition, exploration, and development of new oil and gas reserves, for the purpose of accrual accounting. The higher the depreciation allowance being deducted in any given year, the lower the taxable income and the cash disbursements in the form of income tax (Mian, 2002). It is also seen as a loss in the value of an asset over the time it is being used. Depreciation of a property begins when the property is placed in service for use for the production of income and is stopped when all the cost of the property is recovered or when it is retired from service. Depreciated assets can be either tangible property or intangible property. Tangible property is the property that can be seen or touched. They include land, infrastructures and buildings, cars, trucks, machinery, furniture, equipment, and other property that can be seen and touched. Intangible property, on the other hand, is the property that cannot be seen or touched. These include copyright, franchises, patents, trademarks, and trade names. The intangible property must either be amortized or depreciated using the straight-line method. A depreciable asset must be used to produce income, for a useful life longer than a year and must be subject to wearing out or becoming obsolete. Depreciation of assets can be done by using Straight Line, Declining Balance, Double Declining Balance, Sum of Year Depreciation, and Unit of Production.

Straight Line Depreciation (SLD)

In this method of depreciation, the depreciable cost or cost basis of the property is equally distributed over the useful life of the asset. The following equation is used.

$$D_n = \frac{(C - S_V)}{n} \tag{3.1}$$

Where; D_n is the depreciation in the n-th year, C is the total cost of the depreciable asset, S_v is the salvage value, and n is the useful life of the asset. The straight line depreciation of equipment with a useful life of 6years which cost $50,000 to acquire and has a salvage value of $8,000, is computed as;

$$D_n = \frac{(C - S_V)}{n} = \frac{(\$50{,}000 - \$8{,}000)}{6} = \$7{,}000\ per\ year$$

Declining Balance Depreciation (DBD)

Declining Balance Depreciation method is also referred to as the accelerated depreciation method. This method is appropriate when it can reasonably be estimated that the benefits derived from an asset will decline with time. For each year, a fixed value of a percentage is applied to the book value of the asset, however, unlike the straight-line depreciation method, salvage value is normally not accounted for in this method. Declining balance depreciation is divided into different percentages. These include 125% declining balance, 150% declining balance, 175% declining balance, and 200% declining balance (also known as the Double declining balance depreciation). The fixed percentage is calculated by dividing the above-mentioned percentages by the asset useful life, as given in equation 3.2 below.

$$Fixed\ percentage = \frac{Declining\ Balance}{Asset\ useful\ life} \tag{3.2}$$

Sum of Years' Digits Depreciation (SYDD)

The Sum of Years' Digits Depreciation declining charge is determined each year by dividing the remaining useful asset life by the sum of the years' digits. This is given by the equation 3.3;

$$Sum\ of\ years'digits\ (SYD) = \frac{n(n-1)}{2} \tag{3.3}$$

Where n, is the useful life of the asset. The Sum of Years' Digits Depreciation is computed using the equation 3.4, where C is the cost of the asset, S_V is the salvage value of the asset, and, n_r is the remaining useful life of the asset.

$$D_n = \frac{(C - S_V)n_r}{SYD} \tag{3.4}$$

Unit of Production (UOP)

When an asset loses value not because of time lapse but due to the service it renders, then its depreciation is best determined using UOP depreciation (Onwuka, Iledare, & Echendu, 2012). To determine the unit of production, the capital cost of equipment, C, after deduction of the accumulated depreciation and of the salvage value, S_V, is multiplied by the ratio between the total production in a year and the cumulative production during the useful life of the asset. This is given as;

$$D_n = \frac{(C - S_V)N_a}{\sum N_a} \tag{3.5}$$

3.2.4.3 Cost Recovery Treatment

Cost recovery treatment is an element in PSC, which provides the means through which the contractor or a firm can recover the cost of exploration, development, and operations. Cost recovery limit occurs when a PSC places a limit on how much revenues can be recovered at a given period. This cost recovery limit is the only true distinction between the concessionary system and production sharing contract (PSC) in terms of the mechanism of the two fiscal systems. About 75% of PSCs that have a limit has cost recovery limits of between 40% to 60%, however, most PSCs allow unlimited carry forward of cost recovery (Omowunmi O. Iledare, 2019). Cost recovery in its most basic form was modeled as;

$$CR_t = U_t + CAPEX\ \mathrm{I}\ I_t + OPEX_t + DEP_t + INT_t + INV_t + DECOM_t$$

Where;

$\mathrm{CR_t}$= Cost recovery in year t,

$\mathrm{U_t}$ = Cost recovery carried over from year t-1,

$\mathrm{CAPEX\ I\ I_t}$ = Intangible capital expenditures in year t,

$\mathrm{OPEX_t}$ = Operational expenditure in year t

$\mathrm{DEP_t}$= Depreciation in year t,

$\mathrm{INT_t}$= Interest in financing in year t,

$\mathrm{INV_t}$ = Investment credits and uplift in year t,

$\mathrm{DECOM_t}$= Decommissioning cost recovery fund appointment in the year t.

3.2.5 Profit Oil Split

Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners (the contractor) and the host government at agreed terms often started in the fiscal terms. The contractor's share of profit oil is taxable. The fiscal systems become regressive if the profit oil split percentage is fixed, hence to make the PFS progressive, the profit oil split percentages should be subject to sliding scales. Profit oil is computed as;

$$Profit\ Oil\ (PO) = Gross\ Revenue - Royalties - Cost\ Recovery\ Oil$$

Examples of Profit Oil Splits of some countries

Country	Production, BOPD	Split (%)	Country	Production Level	Split (%)
Bangladesh	Up to 5,000	70/30	**China offshore**	Up to 10,000	90/10
(1989)	5,000-10,000	75/25	(PSC - Dec. 1993)	10,000 -20,000	80/20
(in favor of Gov't)	10,000 -25,000	80/20	(in favor of Cont.)	20,000-40,000	70/30
	25,000-50,000	85/15		40,000-60,000	60/40
	50,001 +	90/10		60,000-100,000	50/50
				Over 100,000	40/60
Egypt					
(1986 Standard model)	Up to 20,000	70/30	**Vietnam**	Up to 15,000	67/33
	20,000-40,000	75/25	(July, 1991)	15,001 -30,000	72/28
(in favor of Gov't)	40,000 +	80/20	(in favor of Gov't)	30,001-70,000	76/24
				70,001-100,000	80/20
Gabon	Up to 5,000	65/35		Over 100,000	Negotiable
(PSC - 1989)	5,000-10,000	70/30			
(in favor of Gov't)	10,001 -20,000	73/27	**Indonesia**		
	20,001-30,000	75/25	(4th Gen., 1988-89)	Profit Oil split	71.2/28.8
	30,001-40,000	80/20	(in favor of Gov't)	Profit Gas split	42.3/57.7
	40,000 +	85/15			

Table 3.6 Examples of Profit Oil Splits of Some Countries

3.3 CASE STUDY

Oftentimes royalties are paid as a percentage of the gross revenue before and any deduction is done. This ends up reducing the revenue allowable for cost recovery. When contractors are not able to recover most their cost but rather pay them to the host government as royalties and economic rents, they will not get enough revenue to expand and develop the current and additional projects. Additional projects developed benefits both the contractor and host government since it increases the total revenue at the end run. A case study has been developed to illustrate how the government can delay the payment of royalties and taxes and still be able to receive approximately the total revenue it is entitled to.

CASE 1: This illustrates the usual calculations for government and contractor takes. With this, the royalty is paid before and any deductions. A Gross revenue of $1000, Cost Recovery of $400, Royalty rate of 20%, the Tax rate of 35%, and Profit oil split of 60/40% in government's favor were used.

CASE 2: This illustrates a delay in royalty payment. The costs were recovered before payment of Royalty. The government and contractor takes were calculated using the same data as given in CASE 1.

CASE 3: This also illustrates a delay in royalty payment. The costs were recovered before payment of Royalty. The government and contractor takes were calculated using the same data as given in CASE 1, but the Royalty rate was increased to 25% and the Tax rate was increased to 40%.

DATA								
Gross Revenue =	1000	USD	Royalty Rate =	20%	25%	Gov't Profit Oil %		60%
Cost Recovery =	400	USD	Tax Rate =	35%	40%	Contractor Profit Oil %		40%
CASE - 1			**CASE - 2**			**CASE - 3**		
	USD			USD			USD	
Gross Revenue =	1000.00		Gross Revenue =	1000.00		Gross Revenue =	1000.00	
Royalty @ 20% =	200.00		Cost Recovery =	400.00		Cost Recovery =	400.00	
Net Revenue =	800.00		After Cost Rec.=	600.00		After Cost Rec.=	600.00	
Cost Recovery =	400.00		Royalty @ 20% =	120.00		Royalty @ 25% =	150.00	
Before Tax =	400.00		Before Tax =	480.00		Before Tax =	450.00	
Tax @ 35% =	140.00		Tax @ 35% =	168.00		Tax @ 40% =	180.00	
After Tax (PO)=	260.00		After Tax (PO) =	312.00		After Tax (PO) =	270.00	
Gov't PO =	156.00		Gov't PO =	187.20		Gov't PO =	162.00	
Cont. PO =	104.00		Cont. PO =	124.80		Cont. PO =	108.00	
Total Gov't Take =	496.00	83%	Total Gov't Take =	475.20	79%	Total Gov't Take =	492.00	82%
Total Cont. Take =	104.00	17%	Total Cont. Take =	124.80	21%	Total Cont. Take =	108.00	18%
	600.00			600.00			600.00	

Table 3.7 Case Study Calculations

From CASE 1(Table 3.7), the Government's take was $496 and the contractor's take was $104, in CASE 2, the government take reduced to $475 while the contractor take increased to $125, when the royalty was delayed, however, in CASE 3, when the royalty and tax rates were adjusted, the government and contractor takes yielded almost the same values as in CASE 1. Therefore, the host government can design the fiscal system to delay royalty and tax payment and still get revenue that it requires. This will encourage more investment and recovery of more reserves.

3.4 GENERALIZED ECONOMIC FIELD DEVELOPMENT PLAN

A Field Development Plan (FDP) provides the best technical solution and the necessary guidance for optimizing the development and production of a petroleum project. It gives the required steerage and information for establishing whether or not a project is economical, by considering all doable development project options, risks and uncertainties so as to define the most optimal development concept. FDP considers the following aspects of petroleum projects economics.

3.4.1 Project Licensing

a) Payment of signature Bonuses

b) Acquiring concession rights

3.4.2 Exploration and Appraisal

a) Geological and Geophysical cost

b) Seismic and reprocessing Cost

c) Exploratory well drilling expenditure

3.4.3 Development

a) Drilling and well completions expenditures

b) Production facilities / equipment cost (CAPEX)

c) Transportation facilities cost

d) Well design expenditure

e) Development Cost

f) General administration Cost

3.4.4 Production

a) Operational cost (OPEX)

b) Workovers / Maintenance Cost

c) Production Cost

3.4.5 Abandonment

a) Decommissioning cost

3.5 ECONOMIC MODEL

3.5.1 Gross Revenue

Gross Revenue = Product × Price

3.5.2 Net Revenue

Net Revenue = Gross Revenue – Royalties

3.5.3 Cost Recovery

$$CR_t = U_t + CAPEX|I_t + OPEX_t + DD\&A_t + INV_t + INT_t + DECOM_t$$

Where;

CR_t = Cost recovery in year t,

U_t = Unrecovered costs carried over from year t-1,

CAPEX | I_t = Intangible capital expenditures in year t,

$OPEX_t$ = Total operating expenditures in year t,

INT_t = Interest in financing (if allowed) in year t,

INV_t = Investment credits and uplift, (if allowed) in year t,

$DD\&A_t$ = Depreciation, Depletion & Amortisation in year t,

$DECOM_t$ = Decommissioning/Abandonment cost recovery fund appointment in the year t.

3.5.4 Taxable Income

$$TXI_t = GR_t - ROY_t - CR_t - TXL_t$$

Where;

TXI_t = Taxable income in year t,

ROY_t = Total royalties paid in year t

CR_t = Cost recovery in year t,

TXL_t = Tax loss carry forward in year t -1,

GR_t = Gross revenues in year t,

3.5.5 Profit Oil

$$PO_t = GR_t - ROY_t - CR_t - TAX_t$$

Where;

PO_t = Profit Oil, CR_t = Cost recovery in year t,

GR_t = Gross revenues in year t, TAX_t = Tax paid in year t

ROY_t = Total royalties paid in year t

3.5.6 Profit Oil Split

The profit oil is split between the contractor and government:

$$PO_t = PO|C_t + PO|G_t$$

Where,

$$\text{Contractor's share } (\mathrm{PO}|\mathrm{C_t}) = \mathrm{PO}(\phi) \times \mathrm{PO_t}$$

$$\text{Government's share } (\mathrm{PO}|\mathrm{G_t}) = (1 - \mathrm{PO}(\phi)) \times \mathrm{PO_t}$$

$$\text{Contractor's Profit Oil Split \% } \big(\mathrm{PO}(\phi)\big); 0 \leq \mathrm{PO}(\phi)$$

3.5.7 Concessionary Economic Model and Its Components

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - TAX_t - OTHER_t$$

Where:

NCF_t = After-tax net cash flow in year t, ROY_t = Total royalties paid in year t,

GR_t = Gross revenues in year t, $BONUS_t$ = Bonus paid in year t,

$OPEX_t$ = Total operating expenditures in year t, TAX_t = Total taxes paid in year t,

$CAPEX_t$ = Total capital expenditures in year t, $OTHER_t$ = other costs paid in year t.

3.5.8 PSC Economic Model and Its Components

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - PO|G_t - TAX_t - OTHER_t$$

Where:

NCF_t = After-tax net cash flow in year t, $BONUS_t$ = Bonus paid in year t,

$OPEX_t$ = Total operating expenditures in year t, GR_t = Gross revenues in year t,

$PO|G_t$ = Government profit oil in year t, ROY_t = Total royalties paid in year t,

TAX_t = Total taxes paid in year t, $CAPEX_t$ = Total capital expenditures

$OTHER_t$ = other costs paid in year t. in year t,

3.6 ECONOMIC EVALUATION

The economic evaluation will focus on analyzing the progressive and regressive nature of the fiscal elements and how they make investment attractive to investors, and their effects on reserves recognition and booking. This will be done by using numerical data (values). Two forms of PSC fiscal systems were used for illustrations. Fiscal system A is a progressive fiscal system which has the fiscal element tie to other parameters and conditions. The fiscal system B is a regressive system with most of the fiscal elements at a fixed rate. A CAPEX and an OPEX of $220 million and $180 million respectively, arriving at an R-factor of 1.5 were incurred to achieve a cumulative production of 50 MMBBL of oil in a year. The royalty and tax rates are given the fiscal systems A and B.

3.6.1 Fiscal System A

a) Progressive Royalty: The royalty rate is tied to the cumulative oil production. It increases as the cumulative production increases. A sliding scale royalty rate was used, this is given in Appendix A. For instance, if the cumulative production is between 10 MMBBL and 20 MMBBL, then the royalty rate is 10%, and so on.

b) Progressive Corporate Tax Rate: This is tied to R-factor. For lower productions, the tax to be paid is small. The scale used for this calculation is given in Appendix - C

c) Cost Recovery Limit: A cost recovery limit of 100% and a loss carried forward of $12million were used.

d) Profit Oil Split: A Profit oil split of 65/35% was used in favor of the host government.

FISCAL SYSTEM - A				
Variables	Calculations	Units	Contractor's Cash Flow (MM$)	Government's Cash Flow (MM$)
Oil Production	50.00	MMBBL		
Crude Oil Price	55.00	USD		
Gross Revenue	2,750.00	MM$		
Royalty (From Appendix - B)	-357.50	MM$		357.50
Net Revenue	2,392.50	MM$		
Loan Carried Forward	-12.00	MM$	12.00	
Capital Expenditure (CAPEX)	-220.00	MM$	220.00	
Operating Cost (OPEX)	-180.00	MM$	180.00	
Taxable Income	1,980.50	MM$		
Corporate Income Tax (From Appendix - B)	-594.15	MM$		357.50
Profit Oil	1,386.35	MM$		
Profit Oil Share (65/35%)			485.22	901.13
NCF			897.22	1,616.13

Table 3.8 NCF Calculations for Fiscal System – A

3.6.2 Fiscal System B

a) Fixed Royalty Rate: A fixed royalty rate of 20% was used. The royalty rate is linked to the cumulative oil production.

b) Fixed Corporate Tax Rate: The Corporate Tax Rate is linked to cumulative production. A fixed tax rate of 30% was used.

c) Cost recovery limit: A cost recovery limit of 100% and a loss carried forward of $12million were used.

d) Profit Oil Split: A Profit oil split of 65/35% was used in favor of the host government.

FISCAL SYSTEM - B				
Variables	Calculations	Units	Contractor's Cash Flow (MM$)	Government's Cash Flow (MM$)
Oil Production	50.00	MMBBL		
Crude Oil Price	55.00	USD		
Gross Revenue	2,750.00	MM$		
Royalty (Fixed Rate) @20%	-550.00	MM$		550.00
Net Revenue	2,200.00	MM$		
Loan Carried Forward	-12.00	MM$	12.00	
Capital Expenditure (CAPEX)	-220.00	MM$	220.00	
Operating Cost (OPEX)	-180.00	MM$	180.00	
Taxable Income	1,788.00	MM$		
Corporate Income Tax (Fixed Rate) @30%	-536.40	MM$		357.50
Profit Oil	1,251.60	MM$		
Profit Oil Share (65/35%)			438.06	813.54
NCF			850.06	1,721.04

Table 3.9 NCF Calculations for Fiscal System - B

3.7 ECONOMIC (PROFITABILITY) INDICATORS

3.7.1 Net Present Value (NPV)

Net present value (NPV) is the difference between the present value of periodic cash inflows and the present value of periodic cash outflows over a period of time, t after they have been discounted. It is usually calculated at a discount rate, i_d, which reflects presumably future investment opportunities; however, the discount rate can be changed during the life of the project. It is suitable for use with probabilities but does not indicate the magnitude of cash flow. NPV is mathematically expressed as;

$$NPV = \sum_{t=1}^{n} \frac{NCF_t}{(1 + i_d)^t} \tag{3.6}$$

Where, $\mathrm{NCF_t}$ is the Net cumulative cash flow at any time, t. If NPV = 0, the project is exactly marginal. If NPV > 0, the project is adding value. If it is < 0, the project is destroying value, but not necessarily unprofitable.

3.7.2 Internal Rate of Return (IRR)

The Internal Rate of Return (IRR) is the discount rate at which the net present value (NPV) of a series of cash receipts and disbursement is exactly equal to zero, or the present value of cash inflows is equal to the present value of cash outflows. The internal rate of return (IRR) is also referred to as the discounted cash flow rate of return, rate of return (ROR), internal yield, the marginal efficiency of capital, and the investors' method. IRR is reported as a percentage and it measures the relative attractiveness of a project. It is calculated using the equation;

$$\sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 \tag{3.7}$$

3.7.3 Present Value Ratio (PVR)

Present Value Ratio (PVR) is a dimensionless ratio of a project's NPV of operating cash flow to the PV of the total investment required using the same discount factor.

$$Present\ Value\ Ratio\ (PVR) = \frac{NPV}{PV\ of\ CAPEX} \tag{3.8}$$

3.7.4 Profitability Index (PI)

The Profitability Index (PI) is the relative profitability of an investment or the present value of benefits per the present worth of every dollar invested. It is considered as an effective measure of capital efficiency. PI is a dimensionless profitability measure obtained from the ratio of the present value of future operating cash flows, and the present value of the investment. PI can be expressed as;

$$Profitability\ Index\ (PI) = 1 + PVR \tag{3.9a}$$

$$PI = \frac{Present\ Value\ of\ Future\ OperatingCash\ Flow}{Present\ Value\ of\ Capital\ Investment} \qquad (3.9b)$$

The PI generates a number greater than one for investments with a positive NPV and a number less than one for investments with a negative NPV. According to Mian, (2002), the decision rules for use of the PI are:

- Accept all independent investment proposals with PI greater than 1.
- Reject all independent investment proposals with PI less than 1.
- The project is break even when the PI = 1.0

3.7.5 Return on Investment (ROI)

Return on Investment (ROI) measures the gain or loss generated on an investment relative to the amount of money invested. This is expressed as:

$$ROI = \frac{Present\ value\ of\ project\ cash\ flow}{Invested\ Capital} \qquad (3.10)$$

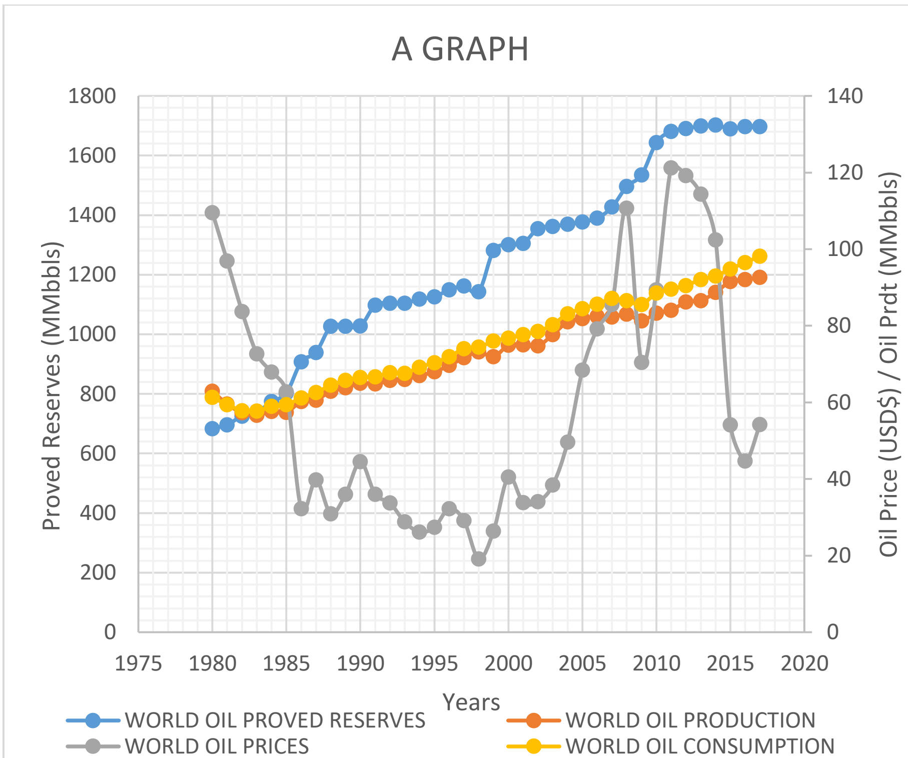
3.7.6 Payout Time (POT)

Payout Time (POT) is the duration it will take to recover exploration and production investments.it indicates the rate at which cash flows are generated early in the project. The tendency of an investor to invest in a project with the shortest Payout Time is high.

CHAPTER FOUR

RESULTS AND ANALYSES

4.1 THE INFLUENCE OF OIL PRICES



From the graph above, it can be observed that the world oil production, world oil consumption, and world proved reserves keep on increasing irrespective of the fluctuations in world oil price. It is a clear fact that whenever there is the demand for oil, there will be production to supply, and as production progresses, reserves have to be discovered to replace the resources produced. In the midst of all these the oil price just affect the profitability of these activities. So in the instance where the elements of a fiscal system are fixed the system becomes regressive and unattractive to investment. Therefore the fiscal elements have to subject to sliding scale to make them progressive and attractive to investors.

4.2 PETROLEUM PROJECT INVESTMENT ANALYSIS GUIDE

To ascertain whether a petroleum project is worth to invest in, economic indicators are often used in analyzing the profitability of the project. Common economic indicators often used include Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), Payout Period (DPO), the Contractor and Government takes, Growth Rate of Return (GRR) and Present Value Ratio (PVR). In addition to these economic indicators, decision rules also serve as a guide to invest in a more profitable project. Table 4.1 shows the decision rules suggested by Iledare (2011). This will be considered in the analyses in this chapter.

Profitability Measure	Accept If @ r*	Reject If @ r*
NPV	> 0	< 0
IRR	> r*	< r*
PI	> 1	< 1
DPO	≤ Desired	≥ Desired
PVR	> 0	< 0
GRR	> r*	< r*
FLI	~ 0	~ 1
Where r* = discount rate or opportunity cost of capital.		

Table 4.1 Capital Budgeting Decision Rules (Iledare O. 2011)

In determining whether a venture is profitable depends on the investors' preferences. A venture might be lucrative to investor A but might not be lucrative to investor B. This is because every company or investor chooses its own minimum rate of doing business (Hurdle Rate) and their desired Payout Period (DPO). With the economic indicators and decision rules given in Table 4.1, an investor would be able to determine the preference for a project.

4.3 EFFECTS OF FISCAL SYSTEM ELEMENTS ON DECISIONS OF INVESTMENTS

Two Models (APPENDIX E and APPENDIX F) were developed to be used in the analysis of the effects of fiscal systems and elements on investment. The two models used the same production profile, capital expenditure (CAPEX), operating expenditure (OPEX), method of depreciation, minimum rate of return and discount rate. However, the progressive fiscal system had its fiscal elements subjected to sliding scales which made it a progressive system, while the regressive fiscal system had its fiscal elements at fixed rates thereby making it a regressive system. Economic indicators were calculated for each of the fiscal systems (as presented in Table 4.2) to analyses how they influence investment decisions.

PROFITABILITY INDICATORS		
Indicator	Progressive FS	Regressive FS
NCF	3366.42	3145.87
NPV	692.37	647.00
IRR	50.28%	48.54%
PVR	2.76	2.58
PI	3.76	3.58
GRR	22.87%	22.57%

Table 4.2 Summary of Economic indicators Results from the models

From the model developed for a progressive fiscal system and regressive fiscal system, the economic indicators estimated are summarized in Table 4.2. This will be used in analyzing the economic viability of a project under each of the fiscal systems and their effects on investment decisions.

4.3.1 The Net Cash Flow (NCF)

The Net Cash Flow (NCF) of the progressive fiscal system was estimated to be $3366.42 million which is higher than $3145.87 million estimated from the regressive fiscal system. The NCF is the parameter used in computing the other economic indicators. The higher the NCF of a project the more profitable the project will be. From Figure 4.2, both the progressive and regressive fiscal system had approximately the same NCF in the initial period of the project, however, the progressive system ended up yielding more NCF than the regressive system afterward. This is because the fiscal elements respond to the periodic changes in production to ensure mutuality of interest between the HG and contractor.

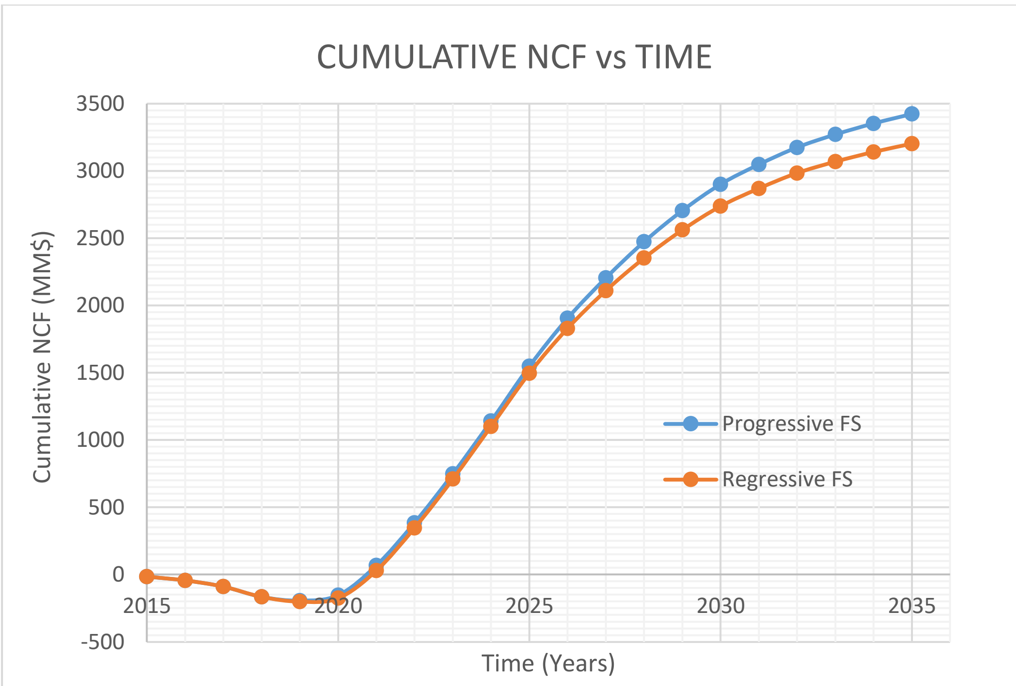


Figure 4.2 Cumulative NCF versus Time Graph

4.3.2 The Net Present Value (NPV)

The Net Present Value (NPV) of a project is expected to be positive (greater than zero) to make an economic sense, however, to be attractive to an investor depends on the investor's preference. The NPV from the progressive fiscal system was estimated to be $692.37 million which is greater than $647.00 million from the regressive fiscal system. The progressive system has its element linked to cumulative production, hence whenever there is high production both the Host government and the contractor gets high return, unlike the regressive system which has the fiscal elements at a fixed rate. Most of the cost incurred in the process of developing a petroleum project is independent of the production level to expect. For instance, spending millions of dollars to drill wells or pay for salaries does not guarantee to get a millions barrel of oil. With regressive systems, the investment becomes less profitable when the production level is low and it subsequently affects future investment and reserve recognitions.

4.3.3 The Internal Rate of Return (IRR)

The Internal Rate of Return (IRR) is an important indicator for analyzing the economic viability of a project. It measures the relative attractiveness of a project. The IRR from the progressive fiscal system is 50.28% and that of the regressive fiscal system is 48.45%. From both models, the IRR is greater than the assumed discount rate (r*) of 15% which show that both fiscal systems make the project viable. However, the difference in the IRR is an indication that one fiscal system is profitable than the other. From the results from the models, the progressive fiscal system appears more profitable than the regressive fiscal system.

4.3.4 Present Value Ratio (PVR)

Present Value Ratio (PVR) from the progressive fiscal system is 2.76 and the regressive system yielded 2.58. An investor has to reject a project with PVR less than zero and accept the project with PVR greater than zero. In the instance where project A and B both have PVR greater than zero, the project with higher PVR is selected.

4.3.5 Profitability Index (PI)

The PI of the progressive fiscal system is 3.76 and that of the regressive fiscal system is 3.58. The two fiscal systems give a PI greater than zero. The progressive fiscal system will be more profitable and attractive to investment than the regressive fiscal system.

4.3.6 Government Take (GT)

Government take is an indicator usually used in comparing fiscal systems of different countries to determine how much wealth is captured by the host government from the oil and gas projects.If fiscal system **A** allows higher government takes than fiscal system **B**, it implies the fiscal system **B** will enable higher cost recovery and revenue return to the contractor than the fiscal system **A** and will be more attractive to invest with. The government take from the progressive system is 45% and the government take from the regressive system is 49%. The progressive fiscal system will be more attractive to investors than the regressive fiscal system.

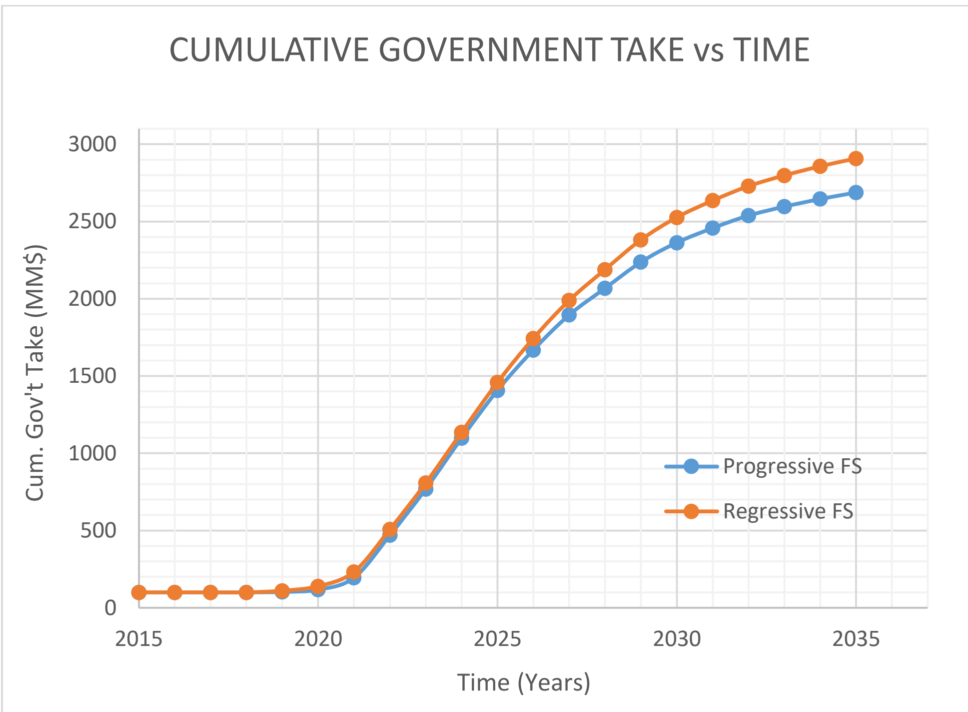


Figure 4.3 Government Take

4.3.7 Growth Rate of Return (GRR)

Growth Rate of Return (GRR) is a reliable profitability indicator used in all cases. It resolves the shortcomings of IRR. The GRR of the progressive fiscal system is 22.87% which is greater than 22.57% from the regressive fiscal system. This was due to the fact that, when Project **A** has a higher PI than Project B, it will again have higher GRR than Project **B** provided the same years and the minimum rate of return (r*) are used. A project is accepted if its GRR is greater than the minimum acceptable rate of return (thus 15%) and is rejected if its GRR is less than the minimum acceptable rate of return. A project will be accepted when used with the two fiscal systems, however, the progressive fiscal system will be more profitable since it gave higher GRR than that of the regressive fiscal system.

4.4 FISCAL INCENTIVES MEASURES TO ATTRACT AND MOTIVATE OIL COMPANIES AND INVESTORS

Investing in petroleum project is very risky and capital intensive. The risk-averse nature of the host government causes him to make provisions and seek investors who will be willing to invest in the project under the fiscal regime and conditions. Although the contractors are risk takers, they look out for the fiscal systems, provisions, and incentives that will yield them a high return on investment. Some of the incentives commonly used are given below.

4.4.1 Discretionary Tax Rates

Certain taxes in petroleum fiscal systems can be deemed discretional. The government makes these provisions to create incentives to attract contractors (investors). By enabling discretionary tax rates, the government enters into negotiations with the oil company to determine the rate. The oil companies are able to negotiate a rate that can account for their cost of production. Discretionary tax rates make the fiscal system progressive and eradicate the stability in the fiscal regime. Royalty and corporate income taxes have historically been set with discretionary tax rates.

4.4.2 Stability Clauses

Stability clauses are implemented to “keep hold” the law of the host country to the date the host government and the oil company entered into an agreement. This is initiated to isolate the oil company from future changes to the host country's law that can possibly harm its investment. Stabilization clauses can be to isolate the oil company from the full or to limit particular aspects of the host country's fiscal and legal regimes for economic equilibrium.

4.4.3 Royalty Holidays

Royalty holidays are fiscal incentives granted by the host government usually during the early life of a contract. The government specifies a particular period of time within which the oil company is exempted from paying royalties in order to encourage higher investments in the country, and in some instances too, to encourage marginal field development. Royalty holidays benefit both the contractor and the government. During this period, the contractor can use the money to develop the property rather than paying it to the government as a royalty. The development of additional investment by the contractor benefits both the host government and the contractor since it increases the total revenue at the end run. After the royalty holiday period, the standard royalty rates are applicable.

4.4.4 Tax Holidays

The tax holiday is a fiscal arrangement instituted by the host government to waive off the payment of income taxes or petroleum taxes for the contractor, during a specified period of time. This serves as an incentive to provide a valuable advantage to investing companies that can fast-track the project payback. This incentive enables the companies to accumulate funds for the discovery of additional reserves and the expansion and development of other projects. However, the oil company is required to pay the standard tax rate after the tax holiday's periods.

4.4.5 Depletion allowances

Depletion allowance is an incentive provision in a fiscal system whereby deduction from gross income is allowed to investors for the depletion of the petroleum resources. The depletion allowance is meant to subsidize further exploration and it is aimed to excite investment in the high-risk industry because, as the reservoir depletes, the company will need to undertake more exploration to find new reserves and resources. Some countries that grant depletion allowances include Barbados, Canada, Pakistan, and the USA.

4.4.6 Loss Carryforward

Loss carryforward is the opportunity granted to the contractor by the host government to recover all the losses from one year to offset tax liability in the future years. When the cost recovery limit and the payback period of a contract system is low, the investor stands the risk of not recovering the cost of investment. This will make the fiscal system less attractive to investors, therefore, implementing loss carryforward which will enable the investor to recover all the cost of investment will make the system very attractive to investors.

4.4.7 Investment uplifts

Investment uplifts are incentives given to the contractor by the host government to recover an additional percentage of tangible capital expenditure. This is very common during the exploration and appraisal phase of a petroleum project. For example, if a company is allowed an uplift of 15% capital uplift in the contract and the contractor spent $800, 000,000 as a recoverable development cost, the contractor can recover a cost of $920,000,000. This incentive encourages investments especially in high risked areas and leads to recognition of more reserves and resources.

4.4.8 Ring – Fencing

Ring-fencing is the provision that required the cost incurred from a location to be recovered with the revenue generated from the same location. Ring-fencing does not allow expenses from a location to be bored by the revenue from a different location. However, when the host government removes this restriction, it enables contractors operating two or more leases to recover cost more quickly. This is an incentive that motivates the contractors to undertake exploration that it might not otherwise find economically attractive.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 SUMMARY

This work presented analyses on the effects of fiscal systems on reserves recognitions and investment matrices. It focused on the various fiscal systems and the ones that support or allow booking and recognition of reserves to aid investors' decisions in adopting a particular fiscal system. It also considered the fiscal elements in the various fiscal systems and how the host governments can handle them to make their fiscal system more attractive to investors, in the same vein, aiding the contractors on what to look out for or consider before investing into a petroleum project.

5.2 CONCLUSIONS

Fiscal systems significantly affect reserves recognition and investment matrix. The decision of an investor is influenced by the return on the investment expected. The host government seeks to obtain maximum revenue from the country's petroleum reserves. In that regards, a progressive fiscal system which addresses the mutuality of interest of the contractor and the host government is best fiscal system proposed to be used. This system can be linked to daily and cumulative productions, R-factor, water depth, locations of concessions, oil prices and other parameters which causes uncertainty in petroleum projects economics. Fiscal elements such as royalty, taxes, bonuses, profit oil split, and recovery limits can be subject to sliding scale rate to make a fiscal system progressive.

Additionally, fiscal elements such as signature and discovery bonuses which requires the contractor to make payments to the host government before cost recovery and/or production can be delayed to recover cost before the payments. This will not cause a significant difference in the government take (as illustrated in Chapter 3), but rather enables to contractor accrue more revenue to expand the projects and discover more reserves which end up benefiting both parties. Such additional investments can serve to further stimulate the economy of the host community, including more employment opportunities, all of which translate to additional tax revenue for the host government.

The host government should always look up to make the country's fiscal system more efficient to attract investors. In some instances, there should be negotiation on some of the fiscal elements to make it more flexible. Fiscal incentives should be as well implemented in the fiscal systems to make the system more lucrative and attractive. This will eventually facilitate the booking and recognition of reserves as well as aid in the discovery of more reserves.

5.3 RECOMMENDATIONS

The following set of recommendations are provided for further studies.

1. The model developed in this work should be tested with actual field data to validate the methodology, observations, and conclusions presented in this work.
2. Sensitivity analyses could also be performed on the fiscal elements to analyze the uncertainties associated with the fiscal elements.

APPENDICES

APPENDIX A - PROGRESSIVE ROYALTY RATES		
Average	**Cumulative Production**	**Royalty Rate**
First Tranche	Up to 10,000 MBBL	5%
Second Tranche	10,001 - 20, 000 MBBL	10%
Third Tranche	20,001 - 40,000 MBBL	15%
Fourth Tranche	Over 40,000 MBBL	20%

APPENDIX B - ROYALTY CALCULATIONS		
Tranche	Calculations	Royalty
First 10000	5% × 10,000	500 MBBL
Next 10000	10% × 10,000	1000 MBBL
Next 20000	15% × 20,000	3000 MBBL
Next 10000	20% × 10,000	2000 MBBL
Royalty Amount =	6500 MBBL ×$55/BBL=	$357.5 million

APPENDIX C – PROGRESSIVE TAX RATES	
R-Factor	Corporate Income Tax Rate
< 1.2	0%
1.2 – 1.3	10%
1.3 – 1.4	20%
1.4 – 1.5	30%
1.5 – 1.6	40%
1.6 – 1.7	50%
> 1.7	60%

APPENDIX D – WORLD PRODUCTION DATA				
YEARS	**Total World Proved Reserves (MMBBLS)**	**Oil Production (MMBBLS)**	**OIL PRICES (US$)**	**Oil Consumption (MMBOPD)**
1980	683.50	62.95	109.56	61.30
1981	696.42	59.55	96.89	59.43
1982	725.51	57.30	83.75	57.83
1983	737.30	56.61	72.72	57.71
1984	774.49	57.65	67.90	58.96
1985	802.56	57.41	62.78	59.37
1986	907.67	60.25	32.27	61.19
1987	938.88	60.61	39.78	62.55
1988	1026.71	62.92	30.92	64.53
1989	1027.27	63.79	36.03	65.77
1990	1027.51	65.00	44.50	66.53
1991	1097.85	64.84	36.00	66.68
1992	1103.83	65.71	33.76	67.78
1993	1104.31	65.97	28.79	67.62
1994	1117.97	66.99	26.16	69.21
1995	1126.16	67.97	27.37	70.38
1996	1148.76	69.64	32.29	71.91
1997	1162.06	71.65	29.16	74.05
1998	1142.41	73.19	19.12	74.45
1999	1281.83	71.89	26.44	76.00
2000	1300.93	74.91	40.56	76.80
2001	1305.39	75.05	33.83	77.68
2002	1354.86	74.73	34.10	78.57
2003	1362.10	77.71	38.41	80.31
2004	1369.03	81.00	49.65	83.16
2005	1377.38	81.88	68.43	84.47
2006	1389.35	82.47	79.21	85.63
2007	1427.09	82.33	85.58	87.10
2008	1495.99	83.07	110.72	86.52
2009	1535.14	81.28	70.46	85.59
2010	1643.06	83.33	89.36	88.53
2011	1681.33	84.03	121.24	89.56
2012	1690.85	86.23	119.22	90.51
2013	1698.67	86.57	114.33	92.09
2014	1702.43	88.72	102.45	92.99
2015	1689.64	91.55	54.18	94.84
2016	1697.08	92.02	44.67	96.49
2017	1696.60	92.65	54.19	98.19

APPENDIX E - DEPRECIATED CAPEX								
Year	CAPITALIZED CAPEX (MM$)		1	2	3	4	5	TOTAL DEPRECIATION (MM$)
2015	56.00		11.20	0.00	0.00	0.00		11.20
2016	66.00		11.20	13.20	0.00	0.00		24.40
2017	82.00		11.20	13.20	16.40	0.00		40.80
2018	115.00		11.20	13.20	16.40	23.00		63.80
2019	0.00		11.20	13.20	16.40	23.00		63.80
2020	0.00		0.00	13.20	16.40	23.00		52.60
2021	0.00		0.00	0.00	16.40	23.00		39.40
2022	0.00		0.00	0.00	0.00	23.00		23.00
2023	0.00		0.00	0.00	0.00	0.00		0.00
2024	0.00		0.00	0.00	0.00	0.00		0.00
2025	0.00		0.00	0.00	0.00	0.00		0.00
2026	0.00		0.00	0.00	0.00	0.00		0.00
2027	0.00		0.00	0.00	0.00	0.00		0.00
2028	0.00		0.00	0.00	0.00	0.00		0.00
2029	0.00		0.00	0.00	0.00	0.00		0.00
2030	0.00		0.00	0.00	0.00	0.00		0.00
2031	0.00		0.00	0.00	0.00	0.00		0.00
2032	0.00		0.00	0.00	0.00	0.00		0.00
2033	0.00		0.00	0.00	0.00	0.00		0.00
2034	0.00		0.00	0.00	0.00	0.00		0.00
2035	0.00		0.00	0.00	0.00	0.00		0.00

APPENDIX F - PROGRESSIVE FISCAL SYSTEM MODEL																		
YEAR BEGINS	Annual Oil Production (MMbbl)	Oil Price ($/BBL)	Gross Revenue (MM$)	Royalties (MM$)	Bonues (MM$)	Net Revenue (MM$)	Total OPEX (MM$)	Total CAPEX (MM$)	Depreciated CAPEX (MM$)	Total Technical Cost (MM$)	NET INCOME BEFORE TAX (MM$)	LOSS C/F (MM$)	TAXABLE INCOME (MM$)	CORPORATE INCOME TAX (MM$)	NET INCOME AFTER TAX (MM$)	HOST GOV'T TAKE (MM$)	CONTRACTOR TAKE (MM$)	NET CASH FLOW (MM$)
2015	0.00	65.00	0.00	0.00	100.00	0.00	4.00	56.00	11.20	15.20	(15.20)	0.00	0.00	0.00	(15.20)	100.00	(115.20)	(15.20)
2016	0.00	69.39	0.00	0.00	0.00	0.00	4.00	66.00	24.40	28.40	(28.40)	(15.20)	0.00	0.00	(28.40)	0.00	(28.40)	(28.40)
2017	0.00	74.08	0.00	0.00	0.00	0.00	5.00	82.00	40.80	45.80	(45.80)	(43.60)	0.00	0.00	(45.80)	0.00	(45.80)	(45.80)
2018	0.00	79.09	0.00	0.00	0.00	0.00	12.36	115.00	63.80	76.16	(76.16)	(89.40)	0.00	0.00	(76.16)	0.00	(76.16)	(76.16)
2019	0.61	84.43	51.84	2.59	0.00	49.25	13.59	0.00	63.80	77.39	(28.14)	(165.56)	0.00	0.00	(28.14)	2.59	(28.14)	(28.14)
2020	1.61	90.14	145.05	14.50	0.00	130.54	38.01	0.00	52.60	90.61	39.93	(193.69)	0.00	0.00	39.93	14.50	39.93	39.93
2021	4.22	96.23	405.82	48.70	0.00	357.12	67.50	0.00	39.40	106.90	250.23	(153.76)	96.46	28.94	221.29	77.64	221.29	221.29
2022	6.57	102.73	674.96	134.99	5.00	534.97	63.01	0.00	23.00	86.01	448.96	0.00	448.96	134.69	314.27	274.68	314.27	314.27
2023	6.57	109.68	720.57	144.11	0.00	576.46	58.86	0.00	0.00	58.86	517.60	0.00	517.60	155.28	362.32	299.39	362.32	362.32
2024	6.57	117.09	769.26	153.85	10.00	605.41	55.21	0.00	0.00	55.21	550.20	0.00	550.20	165.06	385.14	328.91	385.14	385.14
2025	6.15	125.00	768.78	134.54	0.00	634.24	51.37	0.00	0.00	51.37	582.87	0.00	582.87	174.86	408.01	309.40	408.01	408.01
2026	5.38	121.95	656.28	98.44	15.00	542.83	48.78	0.00	0.00	48.78	494.05	0.00	494.05	148.22	345.84	261.66	345.84	345.84
2027	4.71	118.98	560.24	84.04	20.00	456.20	47.92	0.00	0.00	47.92	408.28	0.00	408.28	122.48	285.80	226.52	285.80	285.80
2028	4.12	116.07	478.25	57.39	0.00	420.86	36.62	0.00	0.00	36.62	384.24	0.00	384.24	115.27	268.97	172.66	268.97	268.97
2029	3.61	113.24	408.26	48.99	30.00	329.27	28.37	0.00	0.00	28.37	300.90	0.00	300.90	90.27	210.63	169.26	210.63	210.63
2030	3.15	110.48	348.52	41.82	0.00	306.69	26.68	0.00	0.00	26.68	280.01	0.00	280.01	84.00	196.01	125.83	196.01	196.01
2031	2.42	107.79	260.32	31.24	0.00	229.09	19.44	0.00	0.00	19.44	209.64	0.00	209.64	62.89	146.75	94.13	146.75	146.75
2032	2.11	105.16	222.23	26.67	0.00	195.56	14.17	0.00	0.00	14.17	181.39	0.00	181.39	54.42	126.97	81.08	126.97	126.97
2033	1.62	102.59	165.99	16.60	0.00	149.39	12.10	0.00	0.00	12.10	137.30	0.00	137.30	41.19	96.11	57.79	96.11	96.11
2034	1.42	100.09	141.70	14.17	0.00	127.53	10.33	0.00	0.00	10.33	117.21	0.00	117.21	35.16	82.04	49.33	82.04	82.04
2035	1.24	97.65	120.97	12.10	0.00	108.87	8.82	0.00	0.00	8.82	100.05	0.00	100.05	30.02	70.04	42.11	70.04	70.04
									319.00						**3366.42**	**2687.49**	**3266.42**	**3366.42**

SLIDING SCALE ROYALTY RATE		BONUSES			RATES		GOVERNMENT TAKE	45%	PROFITABILITY INDICATORS		
Up to 1.00 MMbbl	5.00%	Signature	100	$MM	Corporate tax rate =	30%	CONTRACTOR TAKE	55%	INDICATOR		
1.00 - 2.00 MMbbl	10.00%	10 MMbbl	5	$MM					NCF	3366.42	MM$
2.00 - 4.50 MMbbl	12.00%	20 MMbbl	10	$MM	Discount Rate	15%			NPV	692.37	
4.50 - 5.50 MMbbl	15.00%	35 MMbbl	15	$MM					IRR	50.28%	
5.50 - 6.50 MMbbl	17.50%	40 MMbbl	20	$MM	Reinvestment rate	15%			PVR	2.76	
Over 6.50 MMbbl	20.00%	50 MMbbl	30	$MM					PI	3.76	
									GRR	22.87%	

APPENDIX G - REGRESSIVE FISCAL SYSTEM MODEL

YEAR BEGINS	Annual Oil Production (MMbbl)	Oil Price ($/BBL)	Gross Revenue (MM$)	Royalties (MM$)	Bonuses (MM$)	Net Revenue (MM$)	Total OPEX (MM$)	Total CAPEX (MM$)	Depreciated CAPEX (MM$)	Total Technical Cost (MM$)	NET INCOME BEFORE TAX (MM$)	LOSS C/F (MM$)	TAXABLE INCOME (MM$)	CORPORATE INCOME TAX (MM$)	NET INCOME AFTER TAX (MM$)	HOST GOV'T TAKE (MM$)	CONTRACTOR TAKE (MM$)	NET CASH FLOW (MM$)
2015	0.00	65.00	0.00	0.00	100.00	0.00	4.00	56.00	11.20	15.20	(15.20)	0.00	0.00	0.00	(15.20)	100.00	(115.20)	(15.20)
2016	0.00	69.39	0.00	0.00	0.00	0.00	4.00	66.00	24.40	28.40	(28.40)	(15.20)	0.00	0.00	(28.40)	0.00	(28.40)	(28.40)
2017	0.00	74.08	0.00	0.00	0.00	0.00	5.00	82.00	40.80	45.80	(45.80)	(43.60)	0.00	0.00	(45.80)	0.00	(45.80)	(45.80)
2018	0.00	79.09	0.00	0.00	0.00	0.00	12.36	115.00	63.80	76.16	(76.16)	(89.40)	0.00	0.00	(76.16)	0.00	(76.16)	(76.16)
2019	0.61	84.43	51.84	10.37	0.00	41.47	13.59	0.00	63.80	77.39	(35.91)	(165.56)	0.00	0.00	(35.91)	10.37	(35.91)	(35.91)
2020	1.61	90.14	145.05	29.01	0.00	116.04	38.01	0.00	52.60	90.61	25.42	(201.47)	0.00	0.00	25.42	29.01	25.42	25.42
2021	4.22	96.23	405.82	81.16	0.00	324.66	67.50	0.00	39.40	106.90	217.76	(176.04)	41.72	12.51	205.25	93.68	205.25	205.25
2022	6.57	102.73	674.96	134.99	5.00	534.97	63.01	0.00	23.00	86.01	448.96	0.00	448.96	134.69	314.27	274.68	314.27	314.27
2023	6.57	109.68	720.57	144.11	0.00	576.46	58.86	0.00	0.00	58.86	517.60	0.00	517.60	155.28	362.32	299.39	362.32	362.32
2024	6.57	117.09	769.26	153.85	10.00	605.41	55.21	0.00	0.00	55.21	550.20	0.00	550.20	165.06	385.14	328.91	385.14	385.14
2025	6.15	125.00	768.78	153.76	0.00	615.02	51.37	0.00	0.00	51.37	563.65	0.00	563.65	169.10	394.56	322.85	394.56	394.56

2026	5.38	121.95	656.28	131.26	15.00	510.02	48.78	0.00	0.00	48.78	461.24	0.00	461.24	138.37	322.87	284.63	322.87	322.87
2027	4.71	118.98	560.24	112.05	20.00	428.19	47.92	0.00	0.00	47.92	380.27	0.00	380.27	114.08	266.19	246.13	266.19	266.19
2028	4.12	116.07	478.25	95.65	0.00	382.60	36.62	0.00	0.00	36.62	345.98	0.00	345.98	103.80	242.19	199.45	242.19	242.19
2029	3.61	113.24	408.26	81.65	30.00	296.61	28.37	0.00	0.00	28.37	268.24	0.00	268.24	80.47	187.77	192.12	187.77	187.77
2030	3.15	110.48	348.52	69.70	0.00	278.81	26.68	0.00	0.00	26.68	252.13	0.00	252.13	75.64	176.49	145.34	176.49	176.49
2031	2.42	107.79	260.32	52.06	0.00	208.26	19.44	0.00	0.00	19.44	188.81	0.00	188.81	56.64	132.17	108.71	132.17	132.17
2032	2.11	105.16	222.23	44.45	0.00	177.78	14.17	0.00	0.00	14.17	163.61	0.00	163.61	49.08	114.53	93.53	114.53	114.53
2033	1.62	102.59	165.99	33.20	0.00	132.79	12.10	0.00	0.00	12.10	120.70	0.00	120.70	36.21	84.49	69.41	84.49	84.49
2034	1.42	100.09	141.70	28.34	0.00	113.36	10.33	0.00	0.00	10.33	103.04	0.00	103.04	30.91	72.12	59.25	72.12	72.12
2035	1.24	97.65	120.97	24.19	0.00	96.77	8.82	0.00	0.00	8.82	87.96	0.00	87.96	26.39	61.57	50.58	61.57	61.57
																2908.04	**3045.87**	**3145.87**

BONUSES		
Signature	100	$MM
10 MMbbl	5	$MM
20 MMbbl	10	$MM
35 MMbbl	15	$MM
40 MMbbl	20	$MM
50 MMbbl	30	$MM

RATES	
Corporate tax rate =	30%
Discount Rate	15%
Royalty Rate	20%
Reinvestment Rate	15%

GOV'T TAKE	49%
CONTR TAKE	51%

PROFITABILITY INDICATORS		
INDICATOR		
NCF	3145.87	MM$
NPV	647.00	
IRR	48.54%	
PVR	2.58	
PI	3.58	
GRR	22.57%	

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