A comparison of investor attractiveness of oil and gas exploration and production regulatory environments and fiscal regimes in South Africa and Mozambique

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ABSTRACT

The petroleum industry plays an important role both in South Africa (SA) and Mozambique's economies. It is one of the most important sources of energy and the largest single commodity in international trade. This study aimed to explore and compare the fiscal policies of Mozambique and SA in respect of the attractiveness of the fiscal regime used to attract investment to South Africa as opposed to Mozambique. The study explored the evolution of policies in both countries. This was done by comparing the fiscal regimes using a hypothetical case model for both countries, which applied different tax rates and state participation in an oil field project. Net present value (NPV) and internal rate of return (IRR) were used to evaluate the project success and how much the government or the contractor stands to make from the different fiscal regimes. The results showed that the project NPV is highest for the investor when the proposed Mineral Petroleum Resource Bill is applied than the current Mineral and Petroleum Resources Development Act (MPRDA) and the Petroleum Law in Mozambique. The results also showed that the proposed fiscal regime in SA will decrease the NPV for the investor, which makes it less attractive. The study showed that increased state participation has a greater impact on changing the contractor's NPV. If these two governments want to encourage investors to continue exploration in their countries, there should be a balance between the profit that companies make and the revenue that the governments can collect. Thus, the policy recommendation for SA includes having negotiable royalties that promote investment in exploration and increase resources in oil and gas.

Keywords: Exploration and production; Fiscal regime; Investor attractiveness; Mozambique; Oil and gas regulatory dispensations; South Africa.

DECLARATION

I, Anelisa Sigedle, declare that this research report is my own work, except as stated in the references and acknowledgements. I submit it in partial fulfilment of the requirements for the degree of Master of Management in …… at the University of the Witwatersrand, Johannesburg. Someone has not submitted it before for any degree or examination in this or any other university.

Name: Anelisa Signature:

Signed at ……

On the …….. day of …… 2021

DEDICATION

To my sister, Nandipha Sigedle.

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I would like to thank my supervisor, Dr Nyasha Mahonye, for his guidance and support throughout my research studies. Your encouraging words motivated me to persevere throughout my research journey – despite the problems along the way.

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ACRONYMS

ANC	African National Congress
ARCO	Atlantic Richfield Company
BBBEE	Broad-Based Black Economic Empowerment
CAPEX	Capital Expenditure
CIT	Corporate Income Tax
DCF	Discounted Cash Flow
E&P	Exploration and Production
EIA	Energy Information Administration
ENH	Empresa Nacional DE Hidrocarbonetos
FDI	Foreign Direct Investment
FPSO	Floating Production, Storage and Offloading
GDP	Gross Domestic Product
IOC	International Oil Company
IMF	International Monetary Fund
IRR	Internal Rate of Return
JV	Joint Venture

LNG	Liquefied Natural Gas
MBBLS	Million barrels
MPRDA	Mineral and Petroleum Resources Development Act
NCF	Net Cash Flow
NRGI	Natural Resource Government Institute
NPV	Net Present Value
NOC	National Oil Company
OPEX	Operating Expense
PSC	Production Sharing Contract
SAPIA	South African Petroleum Industry Association
TCF	Trillion Cubic Feet

CHAPTER 1: INTRODUCTION

1.1 PURPOSE OF THE STUDY

The goal of this study is to assess and compare the attractiveness of the regulatory environments and fiscal regimes for oil and gas exploration and production (referred to as E&P) in South Africa (SA) and Mozambique. According to Mohamed, (2020), natural resources contribute significantly to the prosperity of many countries, and natural resource rents increase government revenue and influence the trajectory of the gross domestic product (GDP). However, before investing in a project, foreign investors must consider the attractiveness of a country's fiscal regime (Daniel, Keen & McPherson, 2010).

The use of oil and/or gas as primary energy sources has resulted in huge profits, known as petroleum rent, which are divided among all stakeholders in the sector – most notably oil and gas firms and governments in resource-rich nations that host petroleum investments (Don-Serge, 2021). The host government's goal is to maximise fiscal revenue, while investors are concerned with economic indicators, rate of return, and project risk. According to Swe and Emodi (2018), the oil and gas industry analyses and evaluates fiscal regimes using various indicators. Government take, discounted cash flow (DCF), net present value (NPV), and internal rate of return (IRR) are some of these indicators.

Profitability in oil and gas projects takes time. Figure 1 depicts the value chain of oil and gas E&P. As can be seen, there is negative cash flow during exploration, appraisal, and development; the project only has positive cash flow during production. The profitability of both the host government and international oil companies is thus determined using DCFs (Swe & Emodi, 2018).

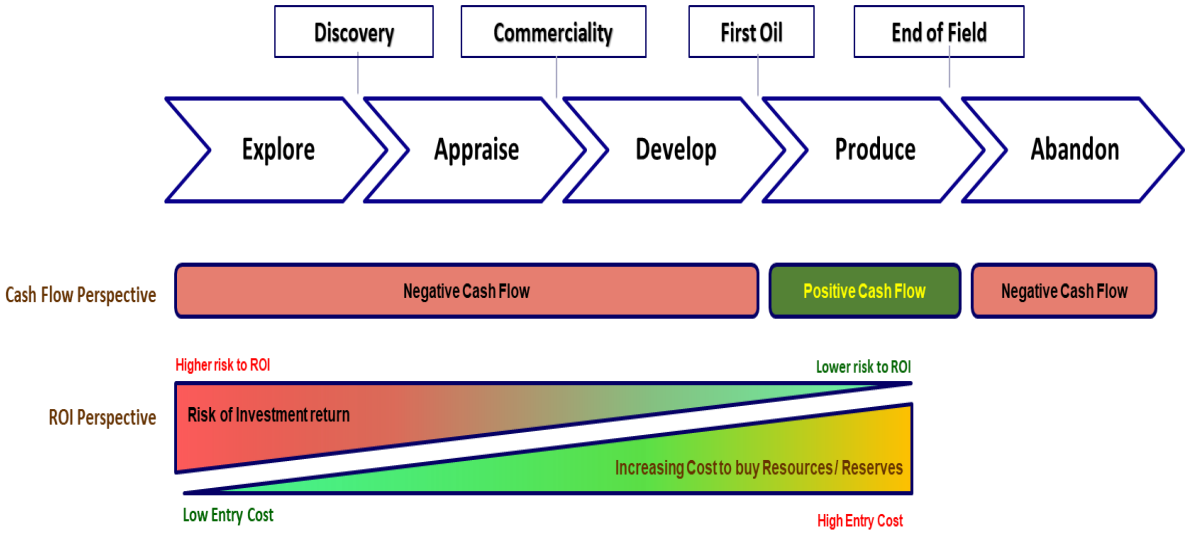

Figure 1: Upstream oil and gas value chain (adapted from Desai Pandian & Vij, 2021)

Oil and natural gas are non-renewable resources. As such, petroleum companies must pay corporate income tax (CIT) as well as mining, oil and gas royalties. In SA, the Mineral and Petroleum Resources Development Act of 2002 (hereafter MPRDA) resulted in increased government rent because, according to the Act (as well as the Freedom Charter), natural resources belong to the people (Department of Minerals , 2002).

SA has approximately 204 trillion cubic feet (Tcf) of gas resources, while Mozambique has approximately 342 Tcf (Deloitte, 2018). Despite the presence of these resources, Africa faces industrialisation challenges. For example, approximately 700 million people in Africa still lack access to electricity, thus delaying economic development (PriceWaterhouseCoopers [PWC], 2018).

SA has established a gas and oil reserve, and the recent discovery of the Total Gas Field has established additional reserves in SA waters (Rodgers, 2021). According to British Petroleum (better known as BP) (2020), the African countries with the largest proven oil reserves are Nigeria (37 million barrels [MBbls]), Libya (48 MBbls), Algeria (12 MBbls), and Angola (8 MBbls). These reserves are based on a 2018 estimate.

Oil production generates significant amounts of wealth for national governments, especially when new oil fields are discovered (Ghebremusse, 2014). Unfortunately, many developing countries lack capacity, particularly the ability to explore additional

resources. As a solution, they rely on their fiscal regime to entice foreign investors to conduct E&P to maximise tax revenue (Ghebremusse, 2014).

The study's goal, therefore, is to examine and assess the attractiveness of SA and Mozambican regulations to investors in the oil and gas E&P industries. It also seeks to compare the regulatory regimes of both countries. Intense growth in exploration has occurred in the last five years as a result of recent regulatory changes in SA and Mozambique. The study will help regulators and policymakers identify gaps in their regulatory frameworks in order to promote oil and gas investment in SA because, after many years with zero exploration, SA has recently discovered more oil and gas reserves on the South Coast (Rodgers, 2021).

1.2 CONTEXT OF THE STUDY

According to Botes, Lane and Cornelissen (2018), regulatory uncertainty has been one of the most significant challenges facing players in the hydrocarbon space in Africa. To develop E&P, oil-rich countries must develop strategic tools capable of attracting petroleum investment. One such tool is a well-designed petroleum fiscal regime that incentivises E&P activities, without jeopardising the host country's ultimate goal of economic development (Don-Serge, 2021)

The approach of this study is twofold. The first part of the study attempts to explore the energy policies/acts/regulatory frameworks in oil and gas E&P in SA and Mozambique. Thereafter, a hypothetical financial model for SA and Mozambique is presented, allowing a comparative assessment of the attractiveness of the regulatory frameworks of these two countries.

Oil and gas resources are relatively underdeveloped in SA, and there is a need for more exploration to improve the resource- and reserve base; thus reducing risk and uncertainties in the industry. E&P is a very capital-intensive industry and a long-term investment. The American Petroleum Institute (Figure 1) shows that petroleum classification is divided into Upstream (which entails exploration), Midstream (transportation and processing), and Downstream (refining) (Desai, Pandian, & Vij, 2021). ‘Upstream’ involves geological surveys, identifying hydrocarbon resources and commercially producing hydrocarbons. During this stage, the industry still requires more investment to develop and grow with regard to exploration.

1.3 BRIEF BACKGROUND OF OIL AND GAS IN SOUTH AFRICA AND MOZAMBIQUE

A new Mining Rights Act was passed in 1967 in SA, and several major corporations, including Total, Gulf Oil, Esso, Shell, Atlantic Richfield Company (ARCO), CFP and Superior, were granted offshore concessions. This resulted in the drilling of the first offshore well in 1969 and the finding of gas and condensate in the Pletmos Basin (Petroleum Agency South Africa [SA], 2020)

In the mid-1970s and late 1980s, Soekor, SA's state-owned oil and gas exploration firm, was the sole explorer working the entire offshore region of SA. Soekor expanded its activities offshore in 1970, however despite more promising discoveries, it gradually removed foreign companies as a result of political sanctions imposed on SA (Petroleum Agency SA, 2010).

The MPRDA was passed in 2002 and came into effect on 1 May 2004. It is the Act that is currently in use and was amended in 2012 (but not signed into law). The current MPRDA terms include a provision for state participation and a state option to acquire up to 10% participating interest from the effective date of mineral, oil and gas production, as well as 10% equity participation reserved for Broad-Based Black Economic Empowerment (BBBEE) companies on fair commercial terms. Changes in oil and gas fiscal terms will have an impact on state participation; all of these terms and sensitivities must be considered when developing the financial model.

There are different international oil companies (IOC) currently offshore of SA, which are regulated by the Petroleum Agency SA. The players involved are PetroSA (state-owned entity), Total SA, TOSACO, Cosmos Energy, Shell, Anadarko, Sasol, Statoil and ExxonMobil (Petroleum Agency SA, 2020).

Mozambique's hydrocarbon exploration dates back more than a century to the discovery of onshore sedimentary basins in 1904. Further onshore discoveries by multinational oil companies in the Mozambique Basin between 1961 and 1967 at Pande, Buzi and Temane proved the existence of hydrocarbon reserves – though their commercial feasibility was unknown at the time. Gqada (2013) states that political unrest in those times halted exploration and therefore the commerciality of the hydrocarbons was not tested. In the early 2000s, Sasol drilled and successfully

evaluated the Temane fields, demonstrating the commercial viability of around 2.7 Tcf gas reserves – equivalent to 25 years of production. Thereafter, more discoveries offshore were made in the Rovuma Basin (Gqada, 2013).

Mozambique was governed by the Petroleum Law 3/2001, which asserts that the state has a right to participate in any exploration blocks. After a more recent discovery of gas in 2014, the Mozambican Government amended the prior law to the Petroleum Law 21/2014 (hereafter the Petroleum Law), which declares that the state also governs the infrastructure related to petroleum. According to Ernest and Young (2018), the fiscal regime that applies to the petroleum industry in Mozambique consists of a combination of CIT, royalty-based taxation, and production sharing. The oil and gas sector in Mozambique has shown remarkable growth, with exploration and investment by international oil companies.

These recent discoveries of gas motivated this study's investigation into the current and proposed fiscal regime in SA. This research, therefore, hopes to ensure more investment in oil and gas in SA.

1.4 RESEARCH PROBLEM

In 2019, gas reserves were discovered on the South Coast of SA by Total SA. The discovery of a gas field opened more opportunities for untapped reserves. Heidi (2019) states that upstream oil and gas fell in the past decade because of less exploration seeking new reserves. This study focuses on oil and gas exploration because the recent gas discovery has increased resources endowment in SA, which could provide energy supply and increase the security of supply. According to Gqada (2013), Mozambique also has proven large oil reserves due to gas discovery in the Rovuma Basin, which increases the resource base of the country. Exploration and production investment decisions are also based on country risk, geological attractiveness, however the study is focusing on fiscal regime attractiveness.

According to Leon (2019), Total SA announced a significant discovery of gas condensate on SA's South Coast – the Brulpadda Prospect on Block 11B/12B in the Outeniqua Basin – which is estimated to contain the equivalent of approximately 1 billion barrels of oil. Following the discovery of new deep-water reserves in SA, it is critical to assess the fiscal regime and its attractiveness to foreign investors. More

importantly, Total cannot develop its discoveries because there is no clear regulatory framework in place, and they must "discuss it with government" (Leon, 2019).

SA has been on a journey to amend its regulatory dispensation since 1994, which creates more interest in whether the current or proposed fiscal regime is attractive for more investment. The petroleum fiscal regime is essential to the government, according to the Natural Resource Government Institute (NRGI) (2015), because it ensures proper management of the country's natural resources.

A country's fiscal regime influences E&P investor decision-making. Currently, there is lower investment in exploration in SA, thus the question is posed: *Is this is due to SA's regulatory environment?* The oil and gas industry is a risky investment, and most investors would require adequate compensation to take on the risk. When governments decide to demand higher rent shares from mining companies by changing tax regimes to favour them as host countries, investors face some uncertainty (Palmer, 1980).

1.5 RESEARCH OBJECTIVES AND RESEARCH QUESTIONS

The main objective of the study is to build a customised economic model that encapsulates the SA fiscal terms and the potential changes to the fiscal regime. The model can then be used to evaluate hypothetical oil and gas development scenarios in SA. Other objectives are to:

- Provide an overview of the SA fiscal terms that apply to the oil and gas sector and compare these to the fiscal regime of Mozambique; and
- Create a customised economic model that includes the fiscal regime for both Mozambique and SA.

The study also seeks to investigate if the fiscal terms are the result of low investment or exploration in SA. In the light of this, the following research question was formulated:

Do the current fiscal regimes in SA and Mozambique promote investment?

1.6 SIGNIFICANCE OF THE STUDY

SA and Mozambique's recent gas discovery has created competition for scarce investment and E&P. One of the most important factors investors consider when

investing in oil and gas is the fiscal regime. Other important factors, such as the geology of the area and political risk, were not considered in this study. The study is relevant to the evaluation of the current and proposed MPRDA in SA, as well as its importance in fiscal terms for the country and in terms of promoting growth in oil and gas exploration. The study demonstrates how the current oil and gas fiscal regime balances the government's objectives and the interests of petroleum investors. Furthermore, the study hopes to add to the existing knowledge of policymakers and players in oil and gas E&P.

The study is significant because it assesses the impact of the current tax regime as well as a desirable fiscal regime that will encourage investment. This information will be useful to investors, as they will be able to decide whether to continue with their investment or look for other opportunities if and when the new regime is implemented.

1.7 DELIMITATIONS OF THE STUDY

The scope of the study was limited to current and proposed policies/acts/fiscal regimes and regulatory frameworks in SA and Mozambique. The current study focuses on offshore exploration in Mozambique and SA. The study is limited to fiscal regimes, the MPRDA in SA and the Petroleum Law in Mozambique. The study has not considered the geology of the area, and the assumptions will be based on hypothetical discoveries in both countries.

1.8 DEFINITION OF TERMS

a) **Free carried interest** is interest allocated to the state in E&P operations without any financial obligation on the state.
b) The **fiscal regime** refers to the financial instruments and the contractual framework which define a host country's share of the wealth accruing from petroleum production through a host of instruments, such as bonuses, royalties, profit, oil, taxes and government participation interest (Amoako-Tuffour, 2010).
c) **Government take** is the proportion of host nation's income from the investment project to the total revenue of the project (Swe & Emodi, 2018).

1.9 ASSUMPTIONS

This study assumes that the SA basins are geologically appealing in terms of oil and gas resources. The study focuses solely on the fiscal regime. It is also assumed that the two models being compared have the same geological risk. Drilling costs will be similar because the geology of the area is assumed to be the same; operating expenditure (OPEX), capital expenditure (CAPEX), and production rate will be the same in the model for both countries. The purpose of this research is to evaluate, validate and calibrate SA's fiscal regime model for gas and oil exploration compared to Mozambique's.

1.10 CONCLUSION

The discovery of the Brulpadda prospects created a new resource opportunity, demonstrating that there is still potential in SA waters (Total, 2019). The discovery of the new deep-water field opens opportunities for new investment in SA. Additionally, Mozambique discovered a massive gas field in the Rovuma Basin, where there is a possibility of a massive liquefied natural gas (LNG) project. These two countries are competing for investment in southern Africa. The study will therefore be useful to the SA Government because it wants to provide a favourable tax environment to attract investors. Investors would find this information useful, whether they continue to invest or look for new opportunities.

The next chapter is a theoretical and empirical literature review on fiscal regimes and investment attractiveness in mineral E&P. It will also define key terms from the study.

1.11 STRUCTURE OF THE REPORT

Chapter 1 introduces the study. It covers the background, why the study was done, as well as the context of the study. The chapter also covers the problem statement, research question and the significance of the study. **Chapter 2** consists of a literature review on topics related to the research question. The chapter critiques the fiscal regimes for oil and gas exploration and development in Mozambique and SA. This chapter also reviews different fiscal tools that are used, such as royalties, CITs, bonuses, production sharing and state participation. **Chapter 3** covers the

methodology used for conducting the study. It also describes the rationale for choosing such a method, as well as the data-collection instruments used in the analysis.

Chapter 4 discusses the findings and results of the study, based on the secondary data collected and the economic model. Thereafter, **Chapter 5** analyses and discusses the research findings. Finally, **Chapter 6** presents the conclusions based on the research findings and how the fiscal regime can contribute to attracting investment in oil and gas exploration and development.

CHAPTER 2: LITERATURE REVIEW

2.1 INTRODUCTION

This chapter contains a literature review that critiques the fiscal regimes for oil and gas exploration and development in both Mozambique and SA. Webster and Watson (2002) state that a literature review consists of analysing and scrutinising the literature that is pertinent to answering a research question. In this chapter, various authors are discussed to understand the research topic variables.

The literature examines how the fiscal regime contributes to investor attractiveness in E&P. The chapter also analyses the relationship of the fiscal regime, policies, and investment by international oil companies. The chapter reviews different fiscal tools that are used in the world, such as royalties, CITs, bonuses, production sharing and state participation. Finally, it reviews the fiscal regimes of SA and Mozambique and ascertains who bears the risk between the host governments and international oil companies.

2.2 DEFINITION OF TOPIC AND BACKGROUND DISCUSSION

According to Carole and Thomas (2019), government policies that are unattractive to investors can drive them away, even where there is proven geological potential. Several countries have had decreasing investments because of uncertainty in the fiscal regime. Venezuela, which has the world's largest proven oil reserves, has seen production fall to record lows as investors shied away from the country due to unfavourable policies and political instability (Carole & Thomas, 2019). In addition, government control can play a huge role in areas where there is limited exploration since the right policies or fiscal regime can reduce the perception of risk in exploration (Carole & Thomas, 2019). Carole and Thomas (2019) state that the government can also affect investment, which could include political stability. This section, therefore, briefly reviews the regulations used in the oil and gas sector and defines how investors and the host country share the rents and production, both in SA and Mozambique.

A fiscal regime is understood as government control used to ensure equity between international oil companies and the state. It is a framework which the government of an oil-producing country employs in managing, regulating and sharing the revenues

that accrue from all the stages of exploitation (Isehunwa & Uzoalor, 2011). This regime is a key factor in decision making by host governments and investors (Luo & Yan, 2010). They tend to be designed for a host country's specific needs and objectives and are generally different from the frontier province to the established oil-producing region. Revenue is the primary source of potential benefits for the host countries, which involves employment, the environment, and the risk appetite of the country; all these factors influence the fiscal regime (Cottarelli, 2012).

According to Nakhle (2008), there are three different strategic options for a country to choose when establishing its policy framework for petroleum production. First, the go-it-alone strategy, whereby the state undertakes production on its own through a national oil company such as in Saudi Arabia, Iran, and Iraq. Secondly, the state grants full private ownership to oil companies that have full control over the operations; this is the case in countries such as the Netherlands, Norway, and Poland (Amoako-Tuffour, 2010) Thirdly, there are two separate forms of ownership, namely private and state participation; these are found in countries such as Ghana, Nigeria and SA.

Countries strive to develop their natural resources and attract foreign direct investment (FDI). Sumarno (2013) claims that fiscal policies failing to attract investment can be due to the unrealistic perception of the host nation's high government take. Sumarno (2013) also confirms that the fiscal regime or regulatory dispensation structured by the host government has a huge impact in terms of attracting FDI.

Host governments design a fiscal regime that maximises revenue from a non–renewable resource while attracting FDI. However, it is in the best interest of international oil companies or investors to ensure that the capital invested is equal to the return, paying attention to the rate of return and NPV of the project (Kaiser & Pulsipher, 2004). Huurdeman and Rozhkova (2019) detail that there are special features in petroleum that could shape fiscal objectives and the choice of fiscal instrument:

- Long and costly exploration periods – an extended time may be needed for investors to determine the commerciality of the project;
- Oil and gas is a captive investment, which means that petroleum projects cannot be moved from one location to another. Therefore, investors always look for a

stable fiscal regime where there is no change that favours the government after the development is made; and

- Significant geological and political risk: petroleum exploration comes with a significant risk of not finding oil and gas, as well as political risks, such as civil unrest.

Two kinds of fiscal regimes prevail in oil and gas exploration (NRGI, 2015). These are shown in Figure 2:

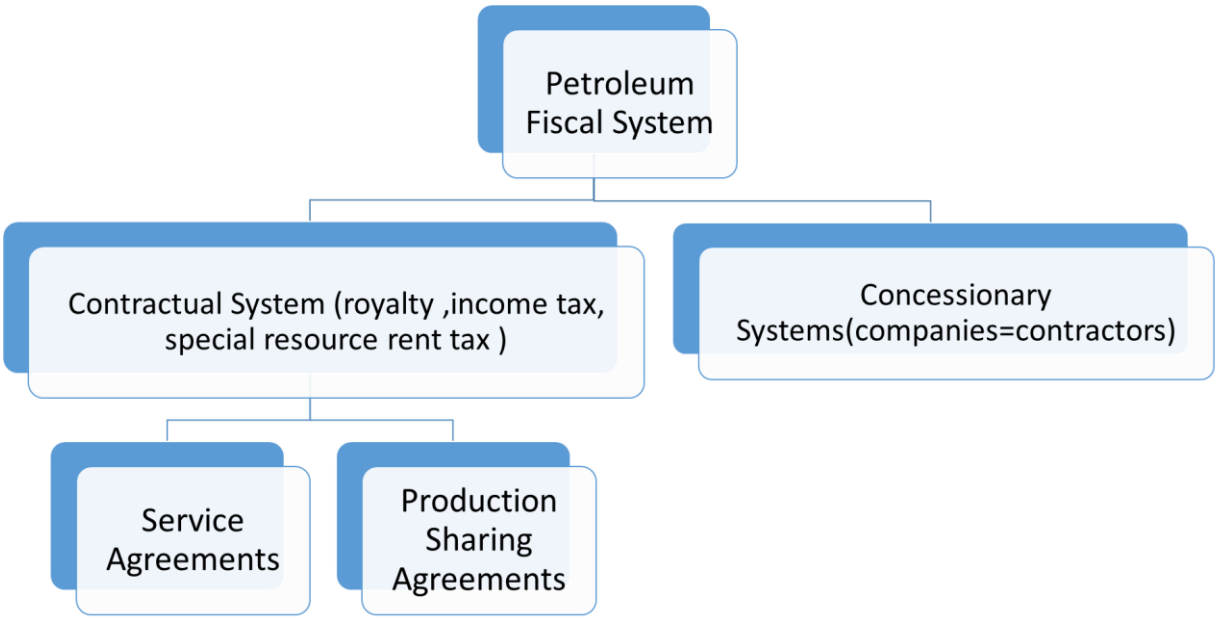

Figure 2: Petroleum fiscal arrangements (NRGI, 2015, p. 6)

The concessionary system is used by different countries such as the United States, United Kingdom, Russia, Norway, France, Argentina, SA, Mozambique and Australia (Ernest & Young, 2014). Although all these countries have the same type of contractual system, their design varies widely in terms of royalty and tax rates (Figure 2), tiers of taxation, and other elements such as incentives to promote investments (Johnston, 2003). In the concessionary system, international oil companies pay a royalty based on the value of the mineral resources expected and the taxable income as laid down in the regulatory dispensation (NRGI, 2015).

With regards to the contractual system, the government has all the mineral assets but will sell blocks for exploration and growth to outside oil companies. The host government grants the oil company the right to earn a share of the production (or revenue) in compliance with a contract for services (Mark & Allan, 2004). In the

contractual system, there is a negotiation between the international oil companies and the host government in terms of profit-sharing depending on anticipated oil and gas production. Table 1 (below) summarises the differences between concessionary, contractual, and contractual service contracts.

Table 1: Fiscal regime summary

Concessionary	Contractual	Contractual service contracts
The state owns the resources	The state owns both resources and production, and a contactor's remuneration is the share of production	The state owns the resources and production. The contactor's remuneration is a fixed cost
The IOC will bear all the risk; government is only exposed to the oil price risk	The contractor bears all exploration and development costs	The contractor bears all exploration and development risks; government takes commercial (oil price) risk
IOC entitlement: gross production less royalty, taxes and bonus	Contractor's entitlement: cost oil plus profit oil, less income tax	Contractor's entitlement: cost oil plus remuneration fee, less income tax

Source: Adapted from Nakhle & Lassourd, 2019.

Governments will encourage investment opportunities by proactively choosing international partners to enhance entry procedures and reduce red tape in oil and gas operations. To do so, they must be successful, understand their geological potential and understand the vital drivers of the IOC they want to partner with (Pongsiri, 2005).

According to Pongsiri (2005), developing nations need to provide an investor-friendly environment to motivate outside investors, especially IOC, in order to expand the streams of exploration. Swe and Emodi (2018) state that countries that have adopted

the concessionary system have a higher government royalty/tax system, which affects fiscal regime attractiveness. Contrarily, countries with contractual service contracts have been more attractive.

2.3 FISCAL COMPONENTS OF A CONCESSIONARY SYSTEM AND CONTRACTUAL SYSTEM

The concession system provides the IOC with the special right to explore, develop and export oil in each territory. It also provides the company with a title to the oil produced, along with the requirement to pay the appropriate royalties and taxes (Carole & Thomas, 2019).

2.3.1 Royalties and production sharing agreement

The government usually imposes a royalty on a specified production amount (unit or common royalty), sales value or gross revenue. From the perspective of a government, a royalty is easy to administer, difficult to prevent, stable (it varies with production) and provides the first source of revenue (as soon as production begins). In countries such as Brazil, royalties are paid every month relative to each field, starting with the one in which the production commenced (Daniel, Keen & McPherson, 2010).

2.3.2 Production sharing agreement

According to Carole and Thomas (2019), in conventional contractual arrangements, the state retains rights to hydrocarbons, and all production belongs to the government unless it is shared. The IOC carries out petroleum activities in accordance with the contract's conditions and at its own risk and expense, supplying all necessary financing and technology. E&P projects are large capital projects where investment involves high risk and high capital. According to Pongsiri (2005), governments will encourage investment opportunities by taking a constructive approach to selecting international partners, to enhance entry procedures and by lifting red tape in oil and gas sector operations.

Many governments are now working hard to strengthen their legal and fiscal structure to provide the transparency, stability and continuity needed to support the substantial level of FDI expected. The most critical of the legislative reforms in the upstream oil and gas industry is the introduction of production legislation (Pongsiri, 2005).

Consequently, governments are tasked with developing and maintaining attractive terms and conditions for investors based on the opportunities offered and the risks to be taken. The design includes some creative and imaginative approaches to the types of contracts offered, and the different fiscal terms used to address the geological potential, such as flexible approaches to the organisation of acreage discovery and flexible development opportunity plans (Thomas & Carole, 2019).

The government may also design contractual ways, such as a cost-recovery system. If the commercial discovery of a resource is made, the company can recover the cost they have incurred during exploration (Daniel, Keen, & McPherson, 2010). Tordo, Arfaa and Tracy (2011) state that the government can also use its licensing system to outline industry structures. This will give the host nation the right to determine the pace of exploration and the licensing of the exploration rights.

There are different views of exploration among IOC in terms of the fiscal and regulatory regime. However, some principles need to be considered when drawing up regulations (Carole & Thomas, 2019). There is no single fiscal instrument that can satisfy all these criteria; countries use a combination of different measures to design fiscal regimes for oil and gas upstream activities which are adapted to their context and goals. The literature also sets out general criteria for evaluating the effectiveness of fiscal system design, namely efficiency, neutrality, equity, risk-sharing, and simplicity (Sen, 2014).

2.4 STATE PARTICIPATION

According to BagherI (2015), the involvement of state-owned firms in significant extractive projects is a common way for the government to participate in the oil, gas, and mining industries. Martén and Martínez de Bourio (2015) state that the share of upstream profits taken by the government is especially important since it determines a country's ability to compete for internationally mobile exploration and development investments.

As stated by Martén and Martínez de Bourio (2015), countries that develop their oil and gas resources entice investors with attractive financial terms. For example, Mozambique offered enticing terms to attract exploration capital, culminating in the finding of more than 100 Tcf of gas reserves. Since then, the country has tightened its terms, which may make investment less appealing in light of decreased oil prices.

It is important to note that state participation varies between petroleum-rich countries and countries that are still developing in oil and gas. Ikezogwo and Boodoo (2014) state that countries such as Angola, with 51% state participation, have high investment rates because of their history of discovery and production since 1965. Ghana, on the other hand, only recently discovered oil in Jubilee Field, which started production in 2010/2011. It has state participation of 10-15%; this is a good benchmark for SA and Mozambique. The proposed bill for SA provides for the insertion of the MPRDA - providing for state participation where the state has, through the designated organ of state, a right to 20% free carried interest in all-new E&P rights.

2.5 THEORETICAL FRAMEWORK

The underlying concept of petroleum taxes is to recover a fair part of the economic rent created by the extraction of oil resources for the host government as the resource owner (Nakhle, 2008). According to Daniel, Keen and McPherson (2010), exploitation of oil and gas involves a high-risk investment with possible great losses or great rewards. Therefore, the host government needs to attract investment for the development and production of oil and gas, as investors can bear the risk of oil and gas E&P. Thereafter, IOC must pay the petroleum taxes to the government, which they in turn use to improve the nation's economy. Governments, therefore, face the challenge of ensuring that the policies are equally beneficial for both the investor and the state because, according to Akinwale and Akinbami (2016), the government aims to maximise its share in taxes. Keeping in mind that the government's objective is to capture a greater share of mining-generated capital, the policies implemented to do so must not be too difficult for investors (Cawood & Oshokoya, 2013).

Resource rent is "the true value of a natural resource, which is the difference between the revenues generated from resource extraction and the costs of extraction" (Garnaut, 1975). Most international oil companies use cash-flow models which are based on the concept of economic rent to evaluate petroleum resource projects (Rose, 2001). The fiscal regime is used as the framework where the host government manages and regulates revenues from the production of oil and gas (Akinwale & Akinbami, 2016).

According to Nakhle (2007), NCFs are a common approach generally used by oil and gas companies in evaluating the viability of the petroleum investment project. The

investor entering a project calculates the return or NPV. Johnston (2003) thus defines economic rent as the value between production cost and the cost to extract the resources.

Present Value Theory, a taxation theory, is the cornerstone of resource rent and governments use this mechanism to generate revenue on behalf of society (Nakhle, 2004). The host countries face two important challenges when designing the fiscal regime, namely ensuring the fair share of revenues to the host country and attracting investment (Nakhle, 2004). Economic rent will therefore be used in this study as revenue representation between a government and investors (IOC). According to Swe and Emodi (2018), the attractiveness will influence the feasibility of the project for IOC. The resource rent model, according to Daniel et al (2010), only taxes positive cash flows and allows all expenses, including capital costs, to be excluded from revenue. If there is a negative cash flow during exploration, it is carried forward to the next year.

According to Akinwale and Akinbami (2016), an economic evaluation of a Nigerian marginal oil and gas field using financial simulation analysis showed that NPV has been used as a yardstick and decision rule on project profitability. NPV is a function of different variables, such as oil price, total gas production, operating expenditure, discount rates and government taxes (Akinwale & Akinbami, 2016). Hou (2009); Gary, Handwerk, Kaiser and Geddes (2007) and Akinwale and Akinbami (2016) have used NPV/IRR as the yard-stick to assess the attractiveness of a fiscal regime by using economic indicators such as cash flow, NPV, PI and IRR to determine the absolute viability or otherwise of a project. According to Abdel and Sani (2014) investors are attracted to a fiscal system that improves NPV. The economic rent was used for this analysis because it is straightforward and accurately represents the revenue split between the host government and the IOC. Furthermore, the nature of oil and gas resources makes it possible to maximise the country's economic rent through the petroleum fiscal system.

2.6 THE EVOLUTION OF MINERAL POLICY IN MOZAMBIQUE

Mozambique gained independence in 1975, but the subsequent civil war had a highly destructive effect on the economy, which only began to recover in the 1990s (BBC, 2020). As a consequence of the long civil war, the natural resources policies and legal

frameworks have not been changed for many years. After the war, there was a need to build trust and certainty in both economic and political institutions for the country to attract FDI in the mining sector. The government was forced to improve the national regulatory system, and strategies for the management and production of petroleum and mining exploration, in order to support the country in responding effectively to the continuous growth of mining and hydrocarbon activities (KPMG, 2013)

In 1986, the Mozambican government enacted its first mining legislation, where the Licensing Authority was given the power to enter into agreements for exploration and mining. The mining law was essentially a mechanism that offered basic licensing rights and varying fiscal incentives; the aim of which was to negotiate contracts on a case-by-case basis (Coakley, 1998). The minerals industry was regulated by the Mining Law No. 2/86 of 16 April 1986, as amended by Law 5/94 of 18 September 1994 (hereafter the Mining Law).

According to Oss (1994), the multi-party elections brought the expectation of long-term stability and security, which would in turn increase FDI. This has come to fruition, with large foreign companies having a market share of 70%, dominating the mining industry (Mtegha, 2005).

As mentioned in Chapter 1, the old Petroleum Law was reviewed in 2001 and 2004 and was amended to the Petroleum Law (Law 3/2001). The new legal regime no longer permitted different types of partnerships between the private investor and the host government. It determined instead that only concession model-based contracts would be granted, and by way of public tenders to any entity fulfilling the applicable requirements. Figure 3 gives further detail on the Petroleum Law in Mozambique.

Reforms to the Mining Law 14/2002 to approve the Mining Law 20/2014 carried expectations that reform would bring about sustainable and fair investments in the sector in the long run. The new legislation proposed the following:

- A requirement that all new mining contracts provide state participation in all operations;
- Local procurement standards where Mozambican citizens can supply and provide goods and services in the mining value chain; and

- The introduction of signing bonuses for mining concessions awarded through public tenders.

The Mining Law 20/2014 of 18 August 2014 (the New Mining Law) came into force on 22 August 2014, replacing the old Mining Law 14/2002 of June 2002. Figure 3 summarises the structure of the current Mining Law in Mozambique. This legislation is innovative in two ways. First, it ensures more competitiveness, transparency and protection of the rights and obligations defined for exploration companies. Secondly, the new legislation safeguards national interests and shares benefits with local communities (Mining Law, 20/2014).

The aim was to create an enabling environment for private sector capital. The government recognises the role of the mineral sector in economic development. To achieve this, the government will promote a promotional and facilitation function. In the last few years, Mozambique has gone through significant changes in the upstream; this was after the discovery of the gas in the Rovuma Basin (Diogo Xavier da Cunha & Miranda & Associates, 2016).

The state reserves the right to participate in the petroleum operations in which any legal entity is involved. The state may also decide to participate in any given project at any stage under the terms to be established by a contract between the state and the holder of the rights. The state also participates in the hydrocarbon sector through two other publicly-owned corporations, namely the Mozambique Hydrocarbon Company and the Mozambique Company for the Gas Pipeline (Petroleum Law, 2014).

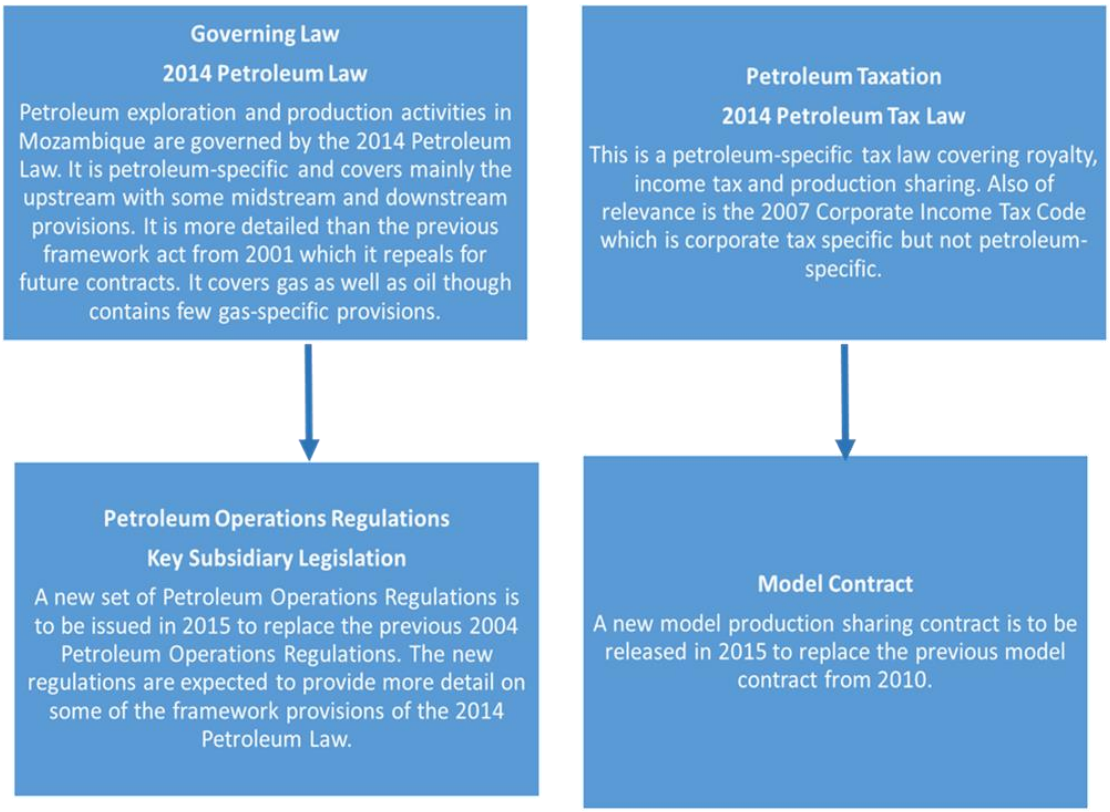

Figure 3: Legal framework of Mozambique's petroleum industry – modified summary from the Petroleum Law (Petroleum Law, 2014)

The evolution of mineral policies in Mozambique has aimed at increasing investment and contributing to economic and social development. Policy changes have also increased state participation in order to benefit the people of Mozambique.

2.7 EVOLUTION OF MINERAL POLICY: SOUTH AFRICA

Mineral laws and mining in SA predate the first European settlers in 1652 (Feinstein, 2005). This was the foundation of the SA economy and mining in general. Many scholars date the Mineral Policy in SA to the period of the Colonies, the Union, the Republic and the Democratic Republic (Mdluli, 2019).

According to legal practitioners and scholars, the SA mineral resources policy is based on common law, as well as Roman-Dutch law, which both state that the landowner is also the owner of the minerals embedded in the land (Mostert, 2014; Schyff, 2012). According to Mostert (2014; p.354):

Regulations varied not only by colony, but also by the type of mineral (distinctions were made between precious stones, precious metals, base metals and/or minerals, natural oil, and nuclear source material) and the type of land involved (whether 'Crown land' or 'private land' during the colonial period or 'state land' during the post-colonial period).

Following the enactment of the South African Act 9 of 1909, the colonies were united to establish the Union of South Africa (Mdluli, 2019). The amalgamation of the four colonies meant that the mineral laws were also amalgamated. In the period 1910–1960, all existing legislation from the four colonies was reviewed and amalgamated to promulgate the legislation that governed the Union (Mostert, 2014).

According to Mostert (2014), the Mining Rights Act of 1967 consolidated all the laws relating to prospecting mining of precious minerals and natural oils. Additionally, the Mineral Rights Act of 1967 indicates that the rights of exploration and exploitation are vested with the state and the landowner. The Act contains the core basic philosophy underlying the mining legislation applicable up to the promulgation of the Minerals Act 50 of 1991. It was clearly stated in this Act (1991) that, while the rights of prospecting for natural oil and of mining for and disposing of precious metals and natural oil is vested in the state, the right of prospecting for and disposing of base minerals on any land is vested in the holder of the right to base minerals in respect of that land (Mdluli, 2019). Furthermore, the Minerals Act 50 of 1991, which heralded the third generation of mineral law, seemingly involved a U-turn in policy because the right to prospect or mine was reverted in the common law mineral right holder. In essence, this meant that the right to decide who could exploit the mineral resource lay with the common law right holder, whereas in previous generations of mineral law this decisional power had been vested in the state (Mostert, 2014).

For the first time since the Minerals Act, a mining company's capacity to rehabilitate became a mandatory factor before the award of an authorisation (Mdluli, 2019). Even though the Minerals Act had no overtly discriminatory clauses, it failed to address the problems of exclusivity and prejudice that had plagued SA mineral law since colonial times. However, the Mineral Act (1991) was legislated at a time of political transition to attract FDI. According to the Act, the right to prospect, mine and dispose of was no

longer vested in the state, which meant that the mineral holders were responsible for mining and rehabilitation of the land.

The change in political dispensation in 1994 initiated a dynamic shift in mining policies (Cawood, 2004). The African National Congress's (ANC) Freedom Charter revealed the intent of the new dispensation when it called for a radical transformation of mineral development.

The ANC also published the *Green Paper on Minerals and Mining Policy for South Africa* for public discussion in February 1998. The Green Paper had a clear mandate: the government's long-term objective was for all mineral rights to be vested in the state. According to Cawood (2004), the Green Paper was a commitment to introducing a dynamic mineral resource management system combined with the efficient administration of mineral rights and the inclusion of BBBEE. Thereafter, the Department of Minerals and Energy published the 1998 White Paper, which was more substantial than the Green Paper and described the exclusive ownership of mineral resources: "The Right to prospect and mine for all minerals will vest in the State". The White Paper also expressed other principles, such as social injustice and BBBEE to increase the participation of previously disadvantaged persons in SA.

The MPRDA is the culmination of mineral sector regulatory reform that started with the 1997 *Green Paper on Minerals and Mining Policy for South Africa*, the 1998 *White Paper on Minerals and Mining Policy for South Africa*, and the 2000 *Draft Minerals Development Bill* (these and other actions taken by the government can be seen in Figure 4). This Act seeks to achieve multiple objectives, such as equitable access to resources, economic development, social welfare and BBBEE. The MPRDA gives the state exclusive authority and responsibility for managing the nation's mineral resource exploitation. Under the MPRDA, control of all mineral rights, including petroleum, is transferred to the state. The MPRDA was amended to the MPRDA 2008; its most significant change is a provision on state participation. The provision gives the state the right to a free carried interest of 20% in all new E&P licences. In addition, the state can acquire a further participation interest by acquisition at a price to be agreed upon (MPRDA, 2002). The MPRDA also vests all mineral and petroleum rights in the state. Below are the Act's objectives:

- Promote equitable access to the nation's mineral and petroleum resources for all citizens of SA;
- Substantially and meaningfully expand opportunities for historically disadvantaged persons, including women, to enter the mineral and petroleum industries and benefit from the exploitation of the nation's resources;
- Promote economic growth and mineral and petroleum resources development;
- Provide for security of tenure in respect of prospecting, exploration, mining and production operations;
- Give effect to Section 24 of the Constitution (which states that "everyone has the right to an environment that is not harmful to their health or well-being and to have the environment protected through reasonable legislative measure") by ensuring that the nation's mineral and petroleum resources are developed in an orderly and ecologically sustainable manner while promoting justifiable social and economic development; and
- Ensure that holders of mining and production rights contribute to the socio-economic development of the areas in which they operate.

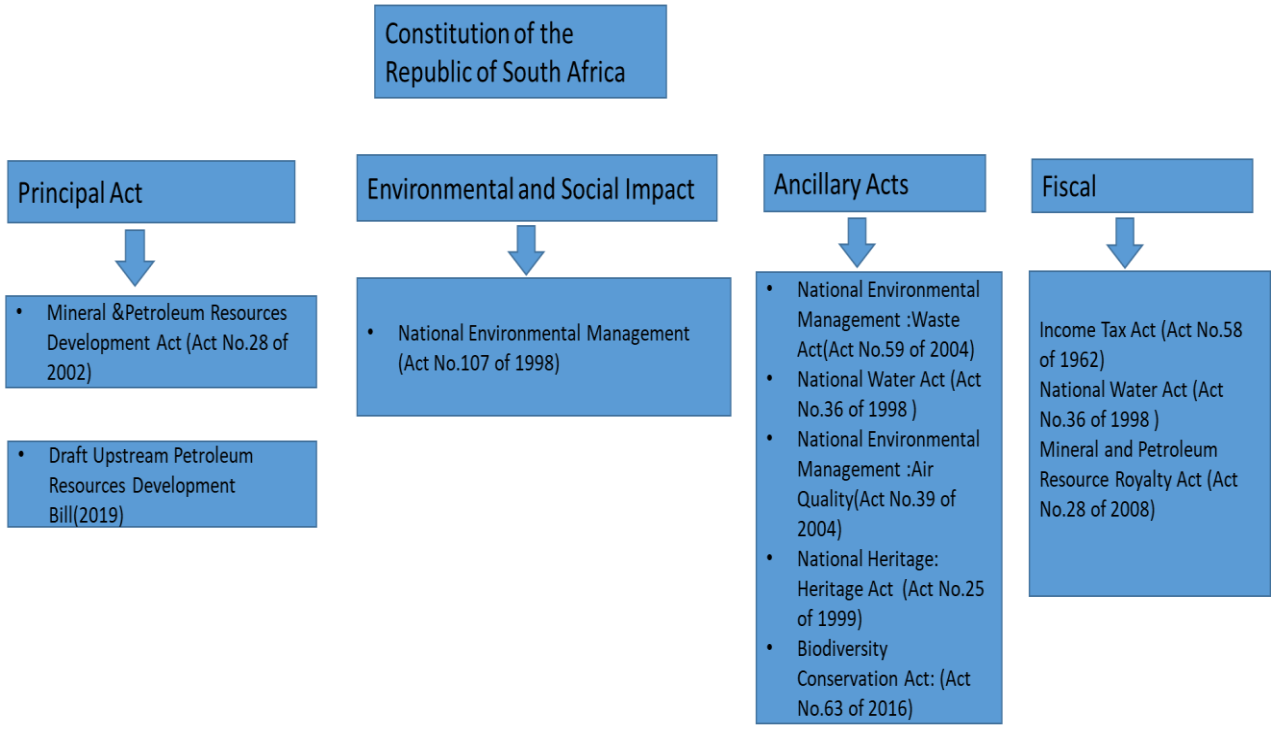

Figure 4: Current legal framework in SA (MPRDA, 2012)

According to the South African Petroleum Industry Association (SAPIA), the fuel sector contributes around 6% to the country's GDP, while also providing 18% of the country's

primary energy needs through annual sales of about 31 billion litres of liquid fuels. SA is still in a growing phase of oil E&P. Figure 5 (in the next sub-section) shows the production and consumption of gas in SA and illustrates a decrease in reserves produced after the year 2006.

2.7.1 Proposed changes in Mineral and Petroleum Resources Development Act

According to the proposed MPRDA (2012), the Bill gives the state the option to acquire a 20% carried interest in all E&P rights through NOC (non-state holders of such rights can recover the state's carried interest development and production costs from the state's portion of proceeds generated from production operations). The proposed MPRDA gives the state a 20% free carried interest without any financial obligation to the state. Therefore, the current study seeks to investigate the impact of increased state participation in attracting investment. According to the proposed changes in MPRDA (in Section 86A):

- *The state has, through the designated organ of state, a right to a 20% free carried interest in all-new E&P rights, from the effective date of such rights; and*
- *In addition to the free carried interest contemplated in subsection above, the state is, in the prescribed manner, entitled to a further participation interest in the form of:*
  (a) *acquisition at an agreed price; or*
  (b) *production-sharing agreements.*

SA is on a journey to separate the petroleum and mineral laws through the *Draft Upstream Petroleum Resources Development Bill* (2019). The separation of Acts for minerals and petroleum will help SA benefit from the abundance of hard rock minerals and responsibly promote petroleum exploration and development investment. For example, there are over 1 500 wells in the Niger Basin, and yet only 35 wells (drilled in the 1980s) in SA's Orange Basin (the West Coast of SA) (IHS, 2018). Mining is a mature industry in SA and the country has been producing and selling minerals since 1871. In contrast, oil and gas production has been limited to an area on the South Coast of SA, where production of gas started in 1992 and oil in 1997.

2.8 FOREIGN DIRECT INVESTMENT (FDI) CORRELATION WITH NATURAL RESOURCE RENTS

According to Mehar, Hasan, Sheikh and Adeeb (2018), natural rents from oil, gas, and coal makes up natural resource rents. In many countries, natural resource rents make a considerable share of the GDP. A large portion of those earnings is available in the form of economic rents revenues, which are larger than the cost of extracting the resources.

In developing countries, the exploitation of natural resources is dominated by foreign investors, which is due to high capital investment. Elheddad (2016; p.233) notes that "Natural resource rents have risen dramatically in countries that rely largely on extractive sectors, but their growth will not be sustainable unless they invest in productive assets". According to Ndikumana and Sarr (2019), several studies have shown that countries with high resource endowment in natural resources may attract high FDI inflow, which has a high correlation with economic rents. However, the relationship between FDI and natural resources rents could be negative if there is an increase in the extractive industry because FDI might decrease in other sectors or "it can be due to export natural resource boom may cause a depreciation of the national currency" (Ndikumana & Sarr 2019). Interestingly, Eissa and Elgammal (2020) state that the availability of natural resources may cause an increase or decrease in FDI, whereas most other authors find that natural resource availability simply attracts FDI. To ascertain if FDI has positive or negative correlations (associative relationship) with mineral, oil and gas rents in both SA and Mozambique, the study has used different variables, namely natural resource rents as the share of GDP and measure of oil/gas rents. This data was extracted from the World Bank Development Indicators (2021).

Figure 5 contains the trends of FDI and natural resources for Mozambique. The graph shows an increase in FDI over the years, with an increase in natural gas resource rents.

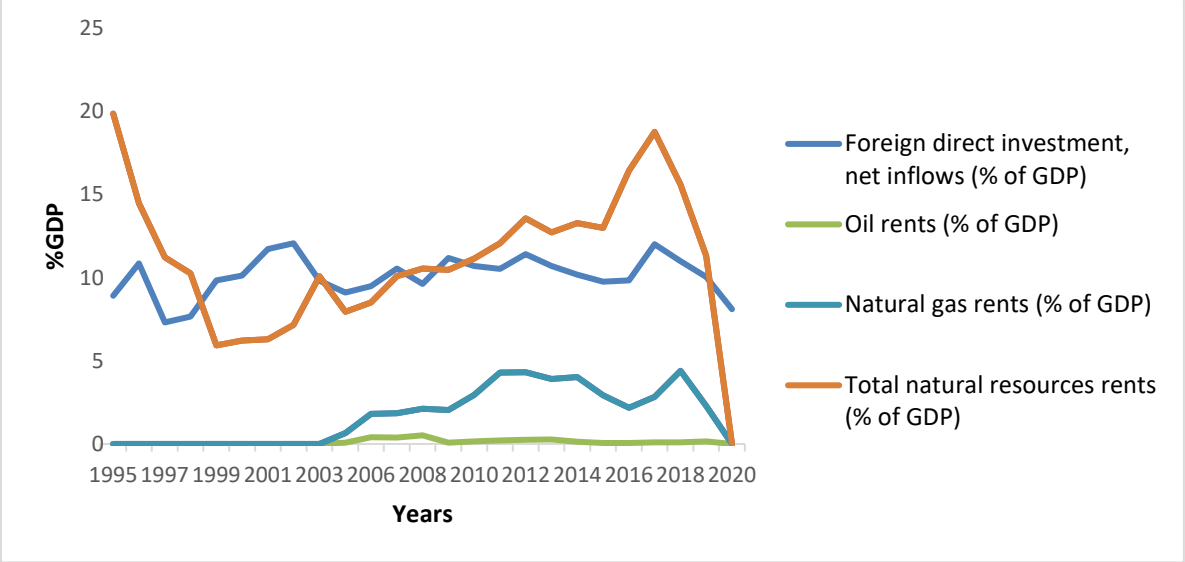

Figure 5: Natural resource rent and FDI (%of GDP) for Mozambique.

Source: World Bank Development Indicators (2021).

Figure 6 shows that there is a direct correlation between the increase in total resource rent and FDI net inflow (percentage of GDP) in SA. The graph shows that when there is a decrease in natural resource rents, there is a decrease in FDI (percentage of GDP).

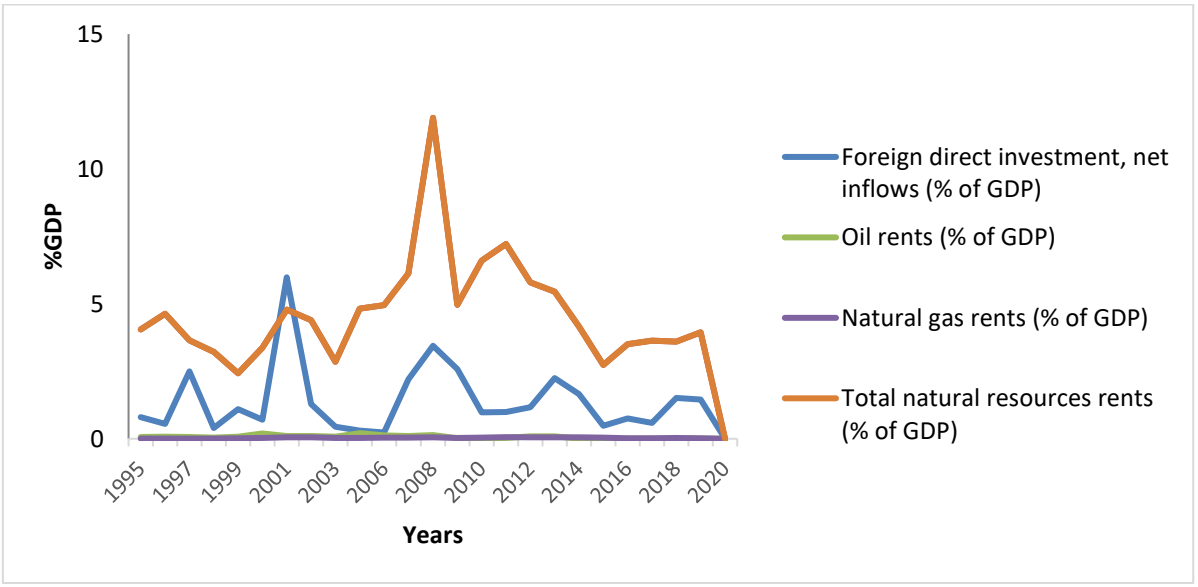

Figure 6: Natural Resource Rent and FDI (% of GDP) for SA.

Source: World Bank Development Indicators (2021).

Table 2 shows the descriptive statistics of the data used for FDI inflows (percentage of GDP) and natural resource rents, using the World Bank Development Indicators. The descriptive statistics show FDI net inflows, as well as mineral, oil and natural rents. FDI ranges between the minimum of 0.22% to a maximum of 39.46%; clearly, FDI varies for both countries. Total natural resource rents range from the minimum of 2.4% to 19%, with an average of 8.12% which shows that there is a contribution of natural resource rents to economic rent.

Table 2: Descriptive statistics

Variable	Mean	Std. Dev.	Minimum	Maximum
FDI	6.96	9.79	0.23	39.46
Mineral Rents	0.62	0.77	0.00	2.76
Oil Rents	0.10	0.11	0.00	0.52
Natural Gas rents	0.90	1.46	0.00	4.40
Total natural resource rents	8.12	4.54	2.43	19.87
Fuel exports	14.37	10.16	0.57	51.42

For Table 3, the Spearman rank correlation test is utilised to attest the direction (show by sign) and magnitude of the associative relationship between FDI, as well as the economic rents obtained from minerals in Mozambique and SA. The table shows the correlation of different variables, specifically FDI, mineral resource rents, and natural gas resource rents. This test ascertains if there is a positive or negative correlation between these variables.

The results show that there is a negative correlation between mineral rents and FDI; it is found to be moderately negative which shows that an increase in FDI reduces mineral rents. The correlation between FDI and oil rent is moderately positive and statistically insignificant. The statistical results also show that there are significant and strong positive correlations between FDI, natural gas and fuel exports. The statistics show that the effect of FDI and natural rents vary depending on the category of the rent and the profile; for example, oil rents were positive but insignificant. Generally, the dataset has shown oil/gas rents have shown a positive effect of FDI inflow, while mineral rent has shown a negative correlation.

Table 3: Spearman rank correlation statistics - FDI and natural resource rents.

	FDI	Mineral rents	Oil rents	Natural Gas rents	Total Natural resource rents	Fuel exports
FDI	1.00					
Mineral Rents	-0.50*	1.00				
Oil Rents	0.25	0.13	1.00			
Natural Gas rents	0.52*	0.11	0.77*	1.00		
Total natural resource rents	0.73*	-0.44*	0.21	0.42*	1.00	
Fuel exports	0.72*	-0.32*	0.34*	0.64*	0.45*	1.00

Table 3 shows that, overall, there is a high level of positive associative relationship between the mining rents and the FDI. Productivity and production in the mining sector, therefore, attract FDI in Mozambique and SA.

This evolution in both South Africa and Mozambique have shown that policies evolve to increase investment. The evolution of these policies have also shown to create an enabling environment for private sector capital. Government recognises the role of the mineral sector in economic development. With the evolution of mineral policy there has been an increase in investment in both South Africa and Mozambique. Oil and gas extracted is purely conditional on mining policy and this is reflected in production levels, mineral exported, and rents generated and their contribution to GDP. The statistics above have also shown that there is a significant and strong positive between FDI, natural gas and fuel exports. Investors often are attracted to countries with mining policies that protects their rights and the profit to be pursued depends on the circumstances or policy environment in the country in question.

2.9 CONCLUSION

The empirical literature shows that a fiscal regime and mineral exploitation play a huge role in attracting investors. The literature also argues that countries use a combination of terms to design fiscal regimes favourable for the exploration and exploitation of mineral resources depending on the maturity of exploration in that country. The other strand of literature indicates that revising fiscal terms over time helps maximise wealth through a country's natural resources and promotes investment. The other strand of literature in mineral exploitation shows that there are conflicting perceptions of the role

of the regulatory environment, government involvement or government take and investor equity. The literature has also shown that state participation and cost recovery affect the attractiveness of a fiscal regime. Many concerns have been raised about how the tax system can be structured to maximise revenue for the government, while still ensuring potential investments.

Mineral taxation is critical for the economic growth of resource-dependant countries. Designing an appropriate tax structure can be difficult, and the government must strike a balance between capturing enough rent to meet the state's needs while still keeping investors comfortable enough to continue investing in the nation. Thus, many concerns have been raised about how the tax system operates.

Mineral mining rights were originally legislated under the Minerals Act 50 of 1991. This all changed during the conversion of old order mining rights to the new order that was brought about by the introduction of the original MPRDA in 2004. The evolution and change of mineral law have also addressed expansion opportunities for historically disadvantaged persons (BBBEE). The MPRDA allowed the promotion of economic growth and mineral/petroleum resource development in the country, with state participation. Descriptive statistics have shown that FDI has positive correlations with oil and gas rents. Results also show that mineral resource rent has a negative correlation with FDI. The results from Mozambique and SA, therefore, show there is a degree of association between resource rent and FDI.

CHAPTER 3: RESEARCH METHODOLOGY

3.1 INTRODUCTION

This chapter details the research methodology that was adopted for the study. According to Flick (2015), methodology refers to the procedure for locating or resolving the research issue. This study, therefore, aims to investigate two related issues, namely the regulatory environment and fiscal regime in both SA and Mozambique. The research paradigm intends to reveal the researcher's perspective on SA's fiscal structure and the effects it has on investment in frontier exploration.

The study uses secondary data for measurement and analysis. One major problem that researchers have faced when trying to quantify the effect of a fiscal regime on investment is access to data. Thus, there are very few options with regards to ways to evaluate a tax system empirically. Therefore, a spreadsheet-based model had to be used for the evaluation.

3.2 RESEARCH APPROACH AND DESIGN

Kumar (2019) outlines two types of data collection: quantitative tools and qualitative data-collection methodologies. Quantitative data-collection tools rely on numbers and are only supported by words during the information-gathering process; examples include questionnaires, observations and official figures such as those in a census. On the other hand, qualitative data collection tools rely on words and are supported by numbers predominantly during the information-gathering process; examples include diaries, interviews and focus groups (Kumar, 2019).

The study has specific objectives. The first is to review the SA fiscal terms that apply to the oil and gas sector compared to the fiscal regime of Mozambique. The second objective is to create a customised economic model that will include the fiscal regime for both Mozambique and SA. Therefore, the research design, which involved the identification of features of the oil and gas regulatory framework and fiscal regime, included a review of the literature, MPRDA and legal documents.

The economic model (excel-based) has an assumptions section that includes information on the fiscal terms and oil and gas pricing assumptions. These

assumptions include the average size of the oil and gas field(s) in both SA and Mozambique, and the average wells needed to produce those reserves. Geological features have been kept identical for both countries, and the quality or the type of hydrocarbons have also been kept similar.

3.3 DATA COLLECTION METHODS

The objective of the study is to analyse and compare the current financial system and regulatory framework for Mozambique and SA. The approach applied was a content analysis of the Mineral Acts and fiscal regime, to enable the researcher to build an economic model which could review the government take and the rate of return for the investor.

The E&P sectors are very confidential, and there is less information on the costing of exploration wells, rig rates and development costs. However, the fiscal regimes are well documented in oil and gas tax reports, government documents, government gazettes, Acts and policies. The data for each economic model was sourced from secondary sources (government documents, AACE international cost estimates, data from oil and gas projects in Africa, regulations from the Natural Resource Institute and US Energy Information Administration [EIA]) and assumptions adopted from previous studies. Secondary data were the most appropriate and available data to review the fiscal regime for both SA and Mozambique.

3.3.1 Secondary data

This is information gathered from the literature that has already been incorporated into the body of knowledge (Quinlan, Babin, Carr & Griffin, 2019). Secondary data are obtained from a variety of sources, including textbooks, journals and newspapers. The downside of secondary data is that particular information may become out of date over time, which could be a problem (Silverman, 2016). It is necessary to evaluate the validity of data when they are available in order to verify that the data are still relevant. With this in mind, collecting secondary data was still useful in answering the research question.

3.4 HYPOTHETICAL BACKGROUND OF THE MODEL

The project is located offshore, on the South Coast of SA. Exploration development is fully financed by an IOC. The life of an oil field is approximately 30 years, including the exploration phase of the project. The offshore infrastructure consists of floating production, storage and offloading (FPSO) (Gupta & Grossmann, 2017). The project is based on an FPSO assumption based on infrastructure requirements for the development of the oil field. The hypothetical model is used because there is a lack of updated data on cost, and the assumptions made resemble those of an actual oil field.

3.4.1 Input data design

Figure 7 (below) tabulates input data, macro assumptions, operating cost, and CAPEX. The figure also shows all the output calculations of the model.

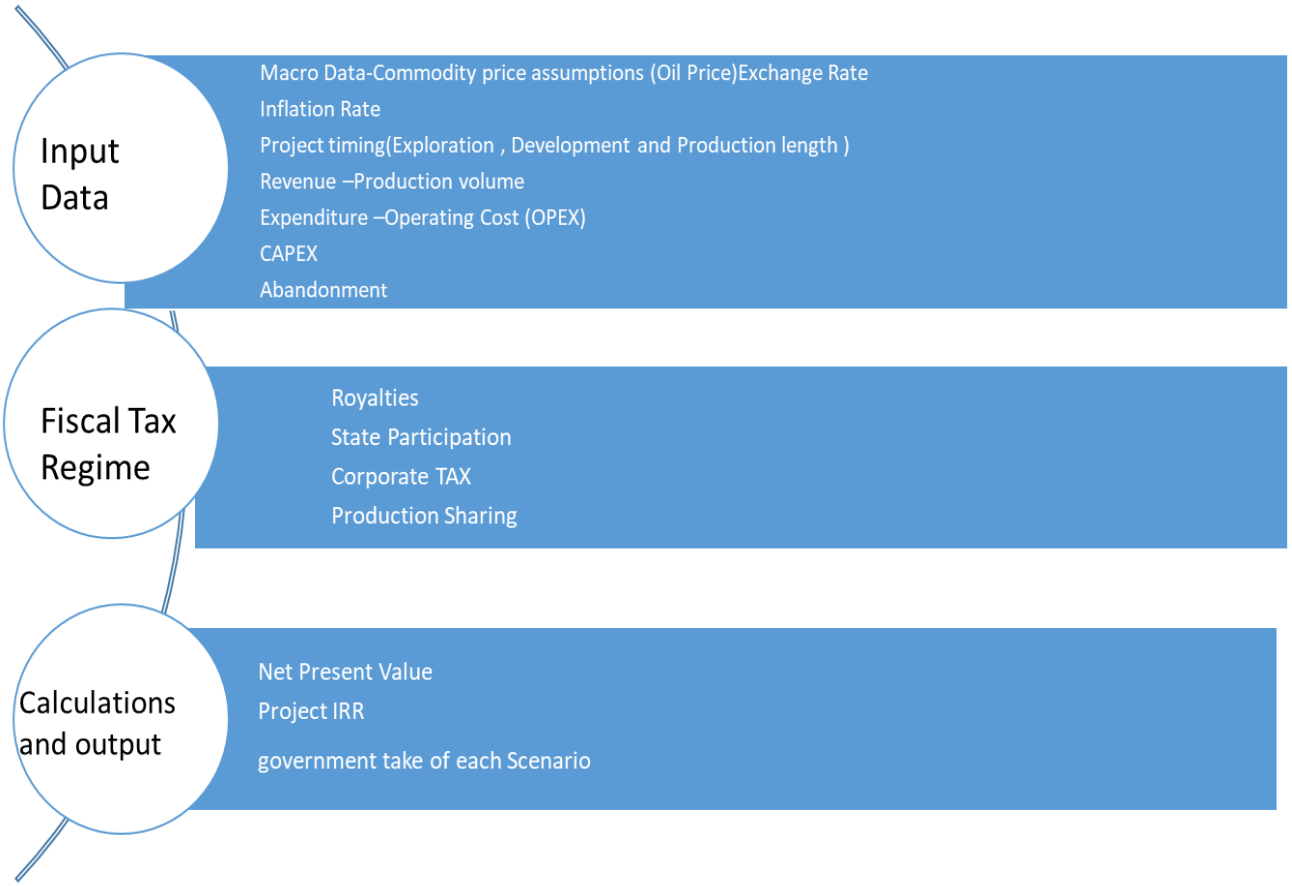

Figure 7: Model workflow and data modified from inputs required to calculate NPV of the project, and a summary of the fiscal tax regime and tax

3.4.2 Model workflow and data

The model has been constructed based on a simplification of reality using a deterministic approach regarding the projection of the oil price. The projection is based on international energy databases, projection of CAPEX, OPEX and inflation. The model has applied the concession contract for Mozambique and SA, where different royalty calculations were applied to determine the government take.

The model evaluated the key business indicators, namely NPV, IRR and take indicators (government take and investor take). Oil price, oil production and field cost can present the most uncertain variables in the model; thus, sensitivity analysis was used to consider inflation and uncertainty in the production of oil as revenue. These input parameters may affect the rate of return and NPV.

3.4.3 Model inputs

The model inputs are made concerning the hypothetical oil fields in SA and Mozambique. Equity is shared between the government take and the investor take. Table 4 shows equity percentages between the parties. The project does not consider any sunk cost. The discount rate of the project was assumed at a 10% maximum discount rate, based on a previous study by Swe and Emodi (2018). Assessment of upstream petroleum fiscal regimes in Myanmar (2018) and Mardiana, Husla and Kartoatmodjo (2019) were also considered at a 10% discount rate (Table 4). Government take assumptions are taken from the MPRDA for SA and the Petroleum Law for Mozambique (Table 4).

The model assumptions were made concerning the hypothetical oil project model. Table 4 details the model assumptions and data sources for the costs and assumptions from the MPRDA and the Petroleum Law.

Table 4: Economic model assumptions for both Mozambique and SA

	Project Detail	**Data Source**
PRODUCTION RIGHT		
IOC	80%	MPRD provision for BBE and state Petroleum Law (2014) and MPRDA (2002)
State	10%	MPRD (2002) provision for BBE and state Petroleum Law (2014) and MPRDA (2002)
BBBEE	10%	MPRD (2002) provision for BBE and state
Concept Design	Concept	
Field Data		
Field Type	Oil	Assumption concept of the field (author's assumptions)
Water Depth	400 m	Average SA water depth
Life of Field	30 years	Assumption of the average life of oil field and the length of production right is 30 years
Reserves (MBbls)	250	Assumption of above minimum field
Product Prices		
Discounting Rate	Average (10%)	Vary the interest rate over the years
Brent ($/bbl.) - nominal	100	Assuming production to start at best case oil price; historical
Fiscal Terms	**SA**	

Corporate Tax Rate	28%	MPRDA
Royalties	5%	MPRDA
Fiscal Terms	**Mozambique**	
Corporate Tax Rate	32%	Petroleum LAW/2014
Royalties	15%	Petroleum LAW/2014
Production Bonus Payable	Maximum USD5 million, depending on monthly production	Production contracts/Ernest and Young Tax Guide
Profit Oil	Shared between operator and government	Petroleum LAW/2014

Source: Petroleum Law (2014) and MPRDA (2002)

The cost estimates for this project are based on conceptual phase development because cost estimates in oil and gas are confidential. Table 5 shows data sources for both exploration and appraisal and development costs.

Table 5: Data source for the economic model assumptions

CAPEX	Data Source
Exploration Costs	International Monetary Fund (IMF) (contract reports between government and investor and assumptions from AACE international cost estimates)
Appraisal Costs	IMF (contract reports between government and investor from AACE international cost estimates)
Development Costs CAPEX (FPSO + Subsea + Drilling)	IMF (contract reports between government and investor from AACE international cost estimates)
Abandonment	IMF (contract reports between government and investor from AACE international cost estimates)

3.5 DATA ANALYSIS AND INTERPRETATION

Data analysis was based on a comparative study between SA and Mozambique and was benchmarked with reviews done worldwide. A framework modelling assessment of an upstream fiscal regime was followed (Swe & Emodi, 2018). The method gives descriptive analysis to all the fiscal term indicators using the economic indicators such as government take, NPV and the contractor/investor take for SA and Mozambique.

3.6 LIMITATIONS OF THE STUDY

A clear limitation of this study surrounds the lack of available data. Cost estimates that were used to determine the indicators are relative and are not real values because the costs in the oil and gas industry are highly confidential.

3.7 VALIDITY AND RELIABILITY

Validity determines how consistently an instrument measures and how accurately the research findings reflect the phenomenon (Salmond, 2008). The study uses fixed historical data and data from policies and Acts. The only variables in the study are the operational costs and CAPEX, which could change if other researchers used the same method.

3.8 ETHICAL CONSIDERATIONS

According to Flick (2014), principles of research ethics ask that researchers avoid harming participants involved in the process by respecting and considering their needs and interests. The study followed the ethical principles as outlined in the Wits policy documents and ethics forms.

CHAPTER 4: PRESENTATION OF RESULTS

4.1 INTRODUCTION

The risk of developing petroleum resources, which includes a drop in the price of oil, has focused on how petroleum revenues are shared between resource owners and companies that extract the petroleum. This chapter describes assessment parameters and a modelling methodology for analysing fiscal regimes in the petroleum sector from the perspective of the host government as well as the investor. The study's methodology determines the fiscal terms to be used in each fiscal regime, which includes royalty, profit split taxes and bonuses. The project also investigates the economics of each model, such as contractor share, IRR and NPV as economic indicators, using the method and the customised model.

The main goal of this chapter is to present the results of a customised economic model that encompasses SA fiscal terms as well as potential changes to the fiscal regime. The model is used to compare and contrast hypothetical oil and gas development scenarios in SA and Mozambique.

4.2 INDICATORS FOR MEASURING THE EVALUATION CRITERIA

The evaluation of a mineral taxation system from the perspective of an investor necessitates an examination of the project's before- and after-tax economics (Swe & Emodi, 2018). This section, therefore, looks at a few different approaches that consider uncertainty and an investor's risk assessment. However, it is important to note that the DCF method is a popular way for investors to calculate the NPV and IRR of a project.

4.2.1 Input worksheets

Assumption inputs are in the form of millions (in dollars), percentages and dates. The Macro Data Inputs sheet pertains to inputs such as the commodity price, interest rates and inflation rates, CAPEX and OPEX.

The model includes the inputs' estimated production volumes, OPEX, capital expenses and abandonment costs. Forecast costs can be input in real or nominal terms, with the appropriate indexation model selected. A key input is the Project Timing, which

determines how the participation scenarios operate for each country. The following definitions are relevant:

- **Exploration phase** – only includes exploration activities;
- **Development phase** – the period where wells are developed, but no production has commenced; and
- **Production phase** – the period where the well is in production.

During the exploration and development phase, there is no positive cash flow in the project but during the production phase, positive cash flow is experienced. Figure 8 (below) gives the summary of all the inputs, hypothetical data, and calculations that are performed in the economic model and the output.

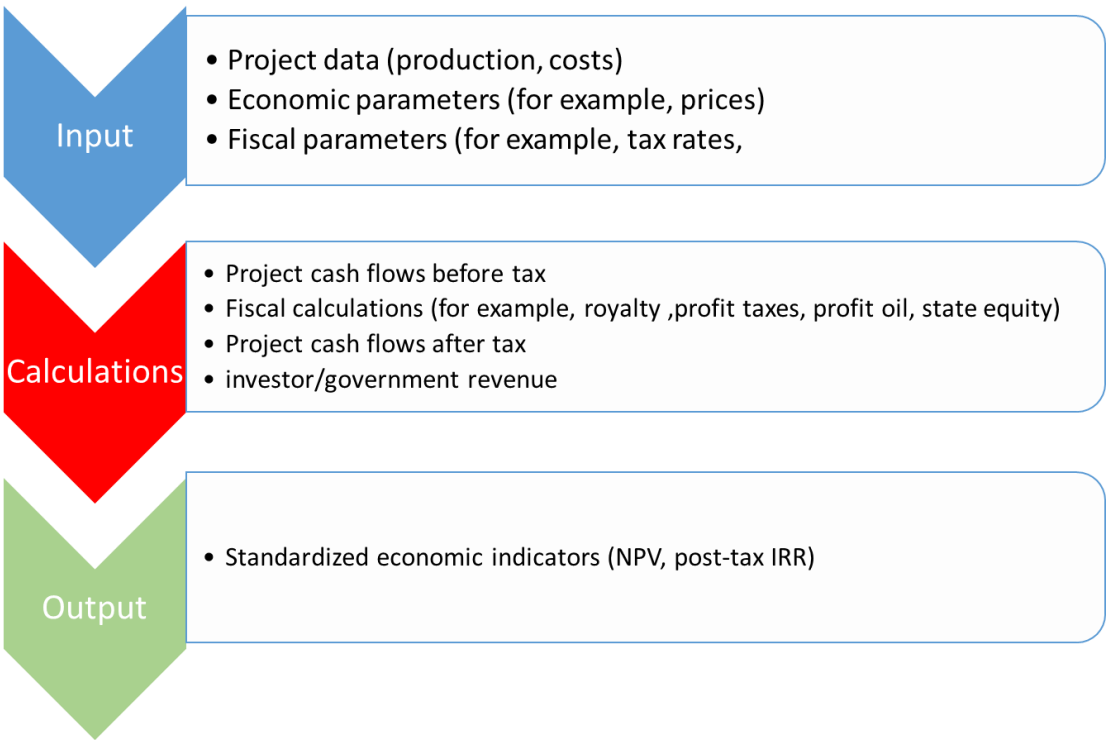

Figure 8: Project input workflow (Luca & Puyo, 2016)

4.2.2 Structure of joint venture

The model assumes the project to be structured as an unincorporated joint venture (JV) partnership between the state and the IOC, with the IOC earning its pro-rata share of revenues and paying its pro-rata share of expenditure.

4.2.3 Taxation

Tax for each JV participant is calculated separately, assuming that each JV participant takes part through a tax ring-fenced entity. This assumption is required to compare the returns of the various participants.

4.3 ECONOMIC MODEL RESULTS

The economic model was developed to generate annual free cash flow for the hypothetical projects. Future cash flows are a major part of what drives a project's worth and are one of the most widely used valuation methods; as such, cash flow analysis was chosen for quantitative purposes. The economic model includes the assumptions for royalty, income tax and state participation. The results of three scenarios for all the models are presented in Tables 6, 7 and 8 for SA and Mozambique. For SA, there are two scenarios – the current MPRDA and the proposed MPRDA with 20% carried interest.

Table 6: Scenario 1 fiscal inputs

Scenario 1 SA	Production Equity (%)
Operator (IOC)	90
State	10
	100

Table 7: Scenario 2 fiscal inputs

Scenario 2 SA	Production Equity (%)
Operator (IOC)	80
State	20
	100

Table 8: Scenario 3 fiscal inputs

Scenario 3 Mozambique	Equity (%)
Operator (IOC)	80
State	20

4.3.1 Hypothetical case

The hypothetical oil field is the simple development of an oil field, with FPSO reflected in the cost of the project. The revenue of the project is dependent on the scale and price of the product (oil). The annual quantities of output from the project measured at the valuation point are referred to as the production profile. With an average field size of 205 MBbls of oil, the assumption in this project was ‘gradual oil production until depletion’.

Figure 9 depicts Mozambique and SA’s oil production and accumulation production until the field’s end of life. The figure depicts a production profile for a petroleum project. After discovery is made, an assessment operation is carried out to determine whether the discovery is profitable. If a planning decision is made, there is a certain amount of time between the start of research and development and the start of production.

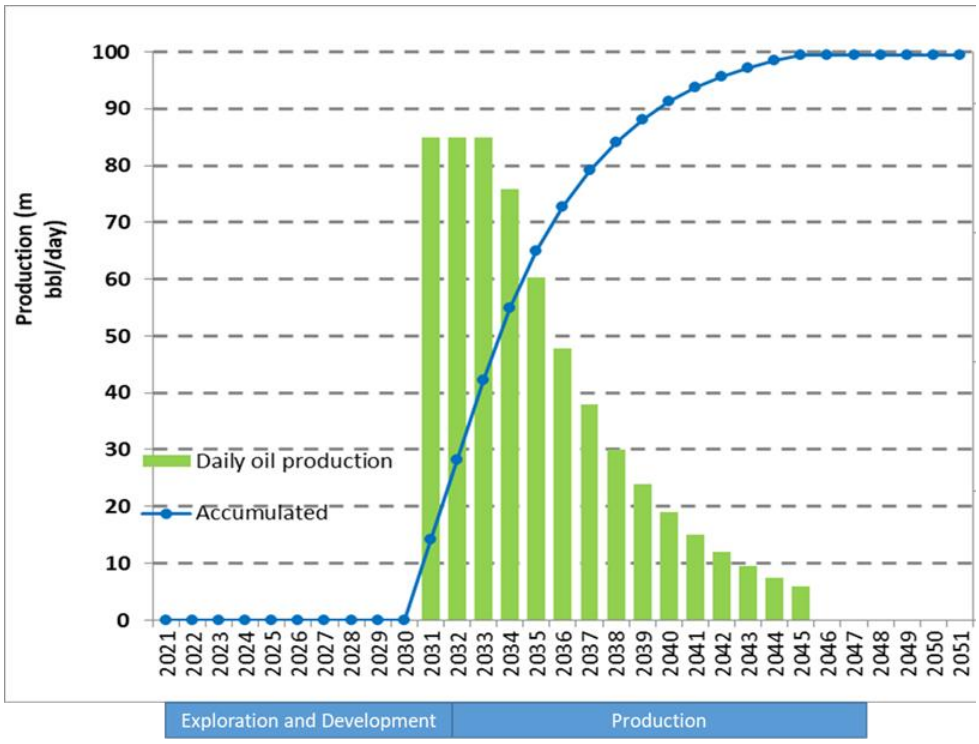

Figure 9: Author’s economic model predictions production profile

4.3.2 Cost of production

Figure 10 (below) shows the distribution of cash flow during the hypothetical project timeline, from exploration until production where there is a positive cash flow. Figure

10 depicts that from 2022, there will be negative cash flow due to investment in exploration, which includes the drilling of wells and the development of the field. The figure also shows that the project will only experience positive cash flow by the year 2037.

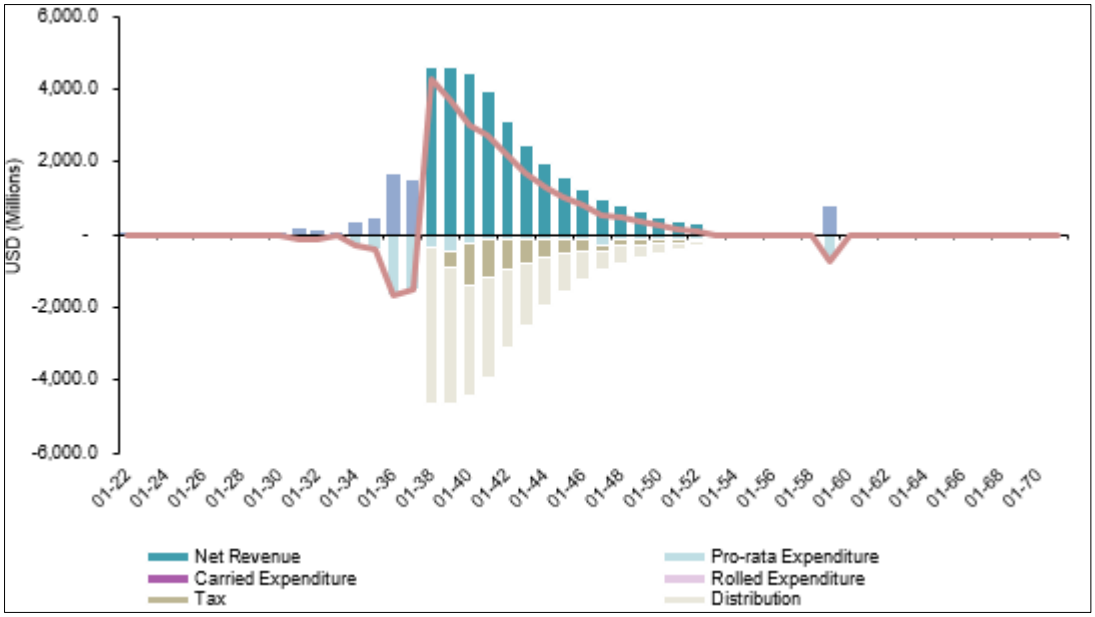

Figure 10: Author's projected project cash-flow from exploration to production; author's economic model prediction

After all the necessary economic and financial parameters are known and the project price and cost data have been entered, the model calculates the project's pre-tax NCF. These constitute the base on which the fiscal calculations will be made later on. The annual pre-tax project NCFs are first calculated in constant dollars (Nakhle, 2010):

$$\text{Pre-tax CFt} = (\text{MarketPrice} \times \text{Production})t - \text{Expl \& Capext} - \text{Opext} - \text{DecommCost} \quad (1)$$

Where the market price and amount of output (Oil Price x Production) determine the sales value of the oil extracted. Exploration costs (Expl) include the project-specific discovery and appraisal costs. Development costs and capital replacement costs during production are included in CAPEX and OPEX are costs directly related to production.

The economic indicators in the results are determined using cash-flow production. This section aims to calculate the effect of the fiscal regime. The distribution of revenue is

attributable to project costs, with a portion going to the government (including taxes, royalties and fees), another portion going to state participation, and the final portion going to the contractor (IOC).

According to Ong (2013), NPV is responsive to the reliability of potential cash inflows that an investment or project would yield, and it is used in capital budgeting to analyse the feasibility of an investment or project. By taking inflation and rate of return into account, NPV compares the value of money earned today to the value of the same sum of money in the future.

$$NPV = CF^0 + CF^1 (1+r)^1 + CF^2 /(1+r)^2 + CF^3 /(1+r)^3 \ldots + CF^n /(1+r)^n \quad (2)$$

CF-Cash Flow (2)

r=Discount Rate

The IRR is the interest rate that equals the value of all cash inflows to the value of all cash outflows, as these cash flows are discounted or multiplied to a single point in time (Ong, 2003). It is vital to consider the relationship between the IRR and the NPV. In reality, it may be one of IRR's defining characteristics. The IRR is the rate at which the project's NPV becomes zero (Ong, 2003).

In the fiscal comparison between the two countries, the same inputs are used for both models, the oil price, and varying project cost. The development scenario includes a volume of 250 MBbls, which will be produced in 15 years. The model is purely for fiscal comparison. Figure 11 shows the prediction of oil prices up to 2030.

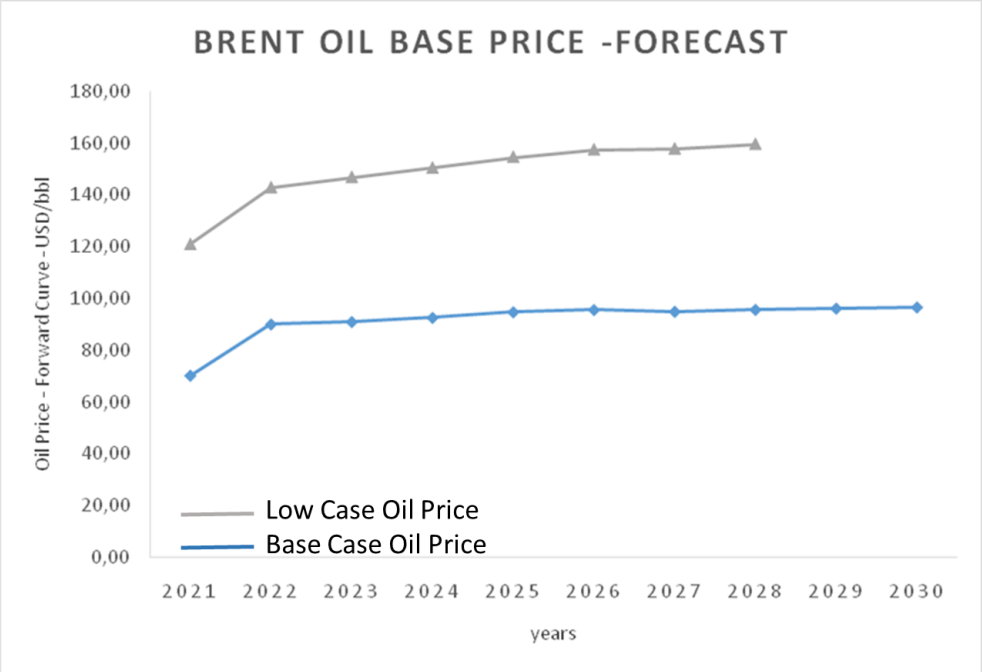

Figure 11: EIA forecasts crude oil prices (EIA, 2020)

The results are term-evaluated with the current MPRDA and proposed MPRDA for SA and the Petroleum Law in Mozambique. In the next section, the distribution of gross revenue between the state and the investor is shown. The results are then taken from the modelling tool to show the summary of the results for each scenario.

4.4 SCENARIO 1: CURRENT MINERAL AND PETROLEUM RESOURCES DEVELOPMENT ACT

The following results show the distribution of net revenue for the state and the IOC, and the distribution of cost, royalty and income tax with the current MPRDA. Scenario 1 (Table 6) entails 10% state participation, 10% BBBEE and 80% IOC investment.

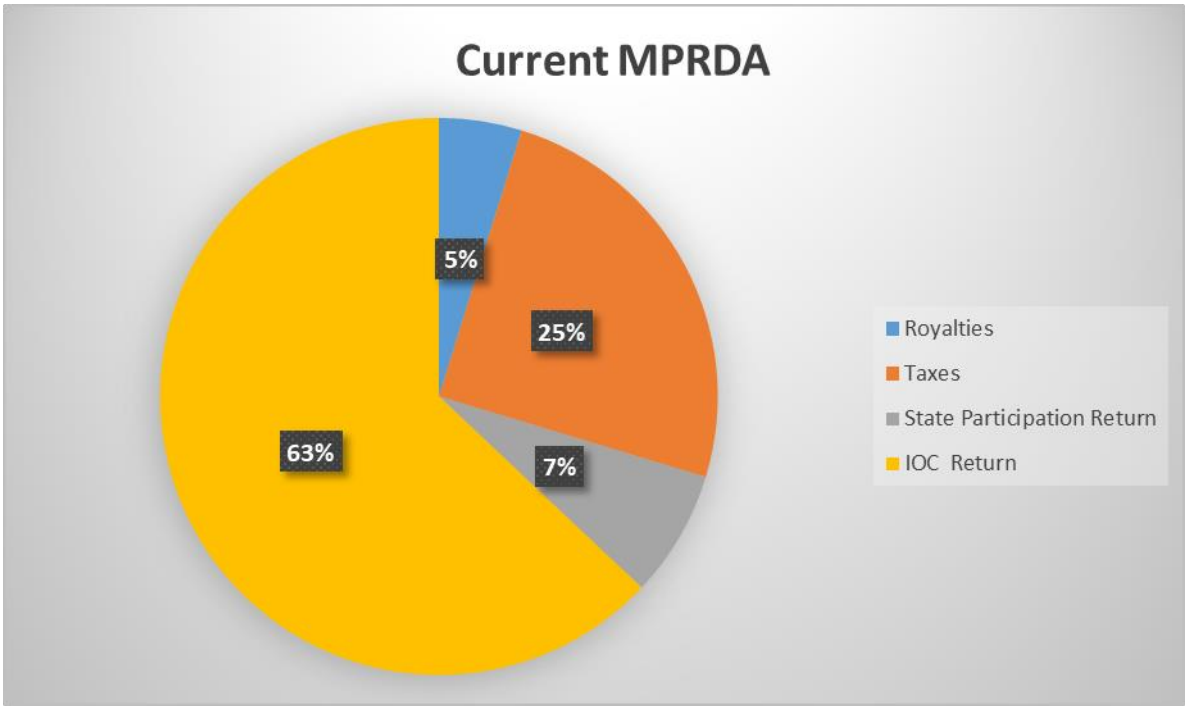

Figure 12: Division of returns (NPV): SA's 10% state participation

The findings in Figure 12 show that 63% of the return goes to the IOC and 7% returns to the NOC (when state participation is 10% as stated in the current MPRDA). The distribution of revenue in Figure 12 illustrates government and contactor take.

4.5 SCENARIO 2: PROPOSED MINERAL AND PETROLEUM RESOURCES DEVELOPMENT ACT

The following results show the distribution of net revenue for both the state and the IOC, and the distribution of cost, royalties and income tax with the MPRDA (2012). Scenario 2 (Table 7) entails 20% state participation and 80% IOC investment.

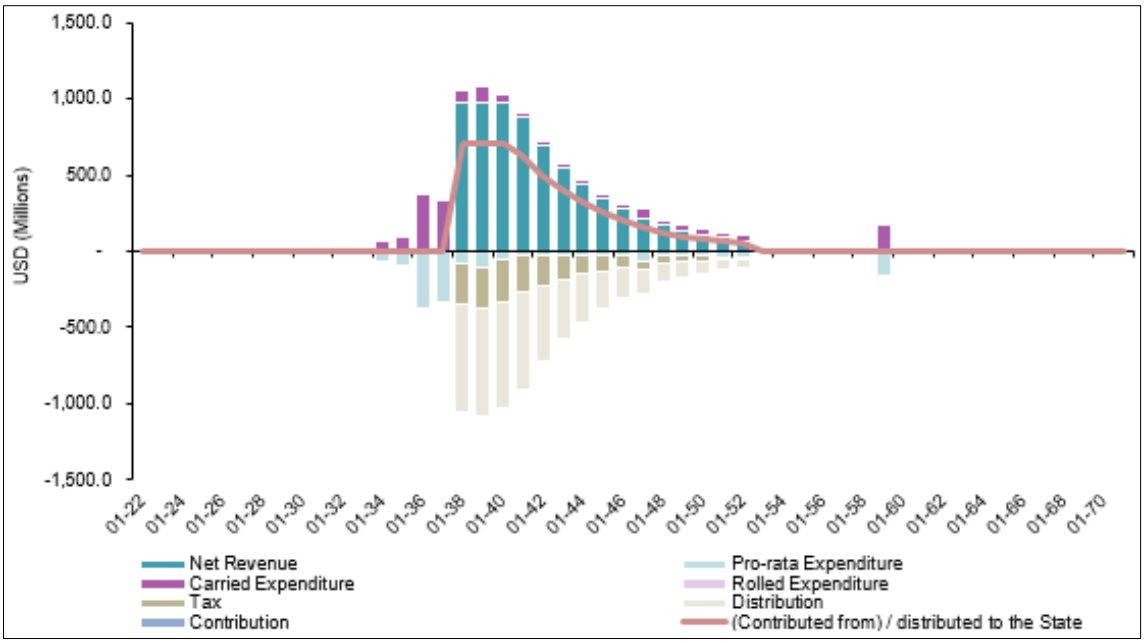

Figure 13: Author's projected project cash-flow from exploration to production; author's economic model prediction with 20% fully carried from exploration to production

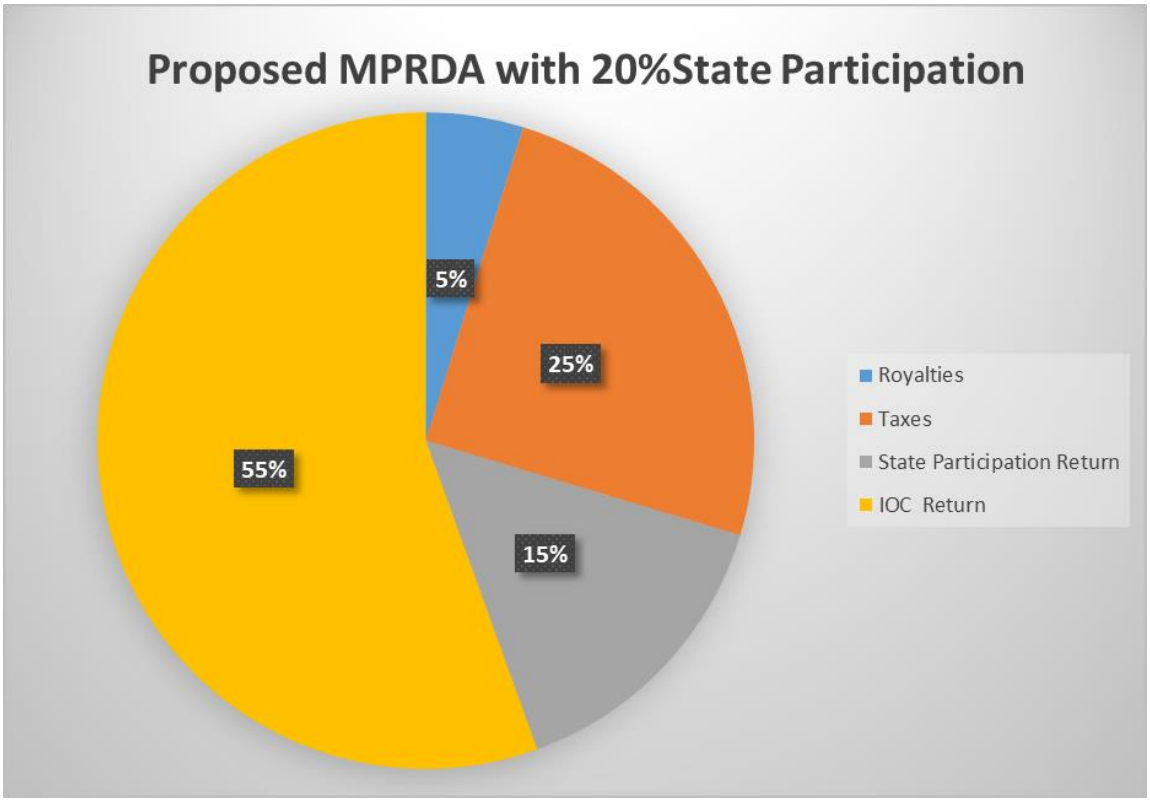

Figure 14: Division of returns SA: 20% state participation

Scenario 2, which is the proposed MPRDA with 20% state participation with fully carried (20%), shows that there is an increase in NOC returns and a decrease in IOC

return (Figure 14). Scenario 2 then suggests that according to the investor's perspective, it is less favourable than Scenario 1 in terms of returns.

4.6 SCENARIO 3: MOZAMBIQUE ATTRACTIVENESS OF FISCAL REGIME PETROLEUM LAW 2014

The findings also show that IOC returns in Mozambique using the Petroleum Law are much higher than returns in a similar field in SA in both cases. The following results show the distribution of NPV for both the state and the IOC, and the distribution of cost, royalties and income tax as per the Petroleum Law in Mozambique. Table 8 was used as an assumption.

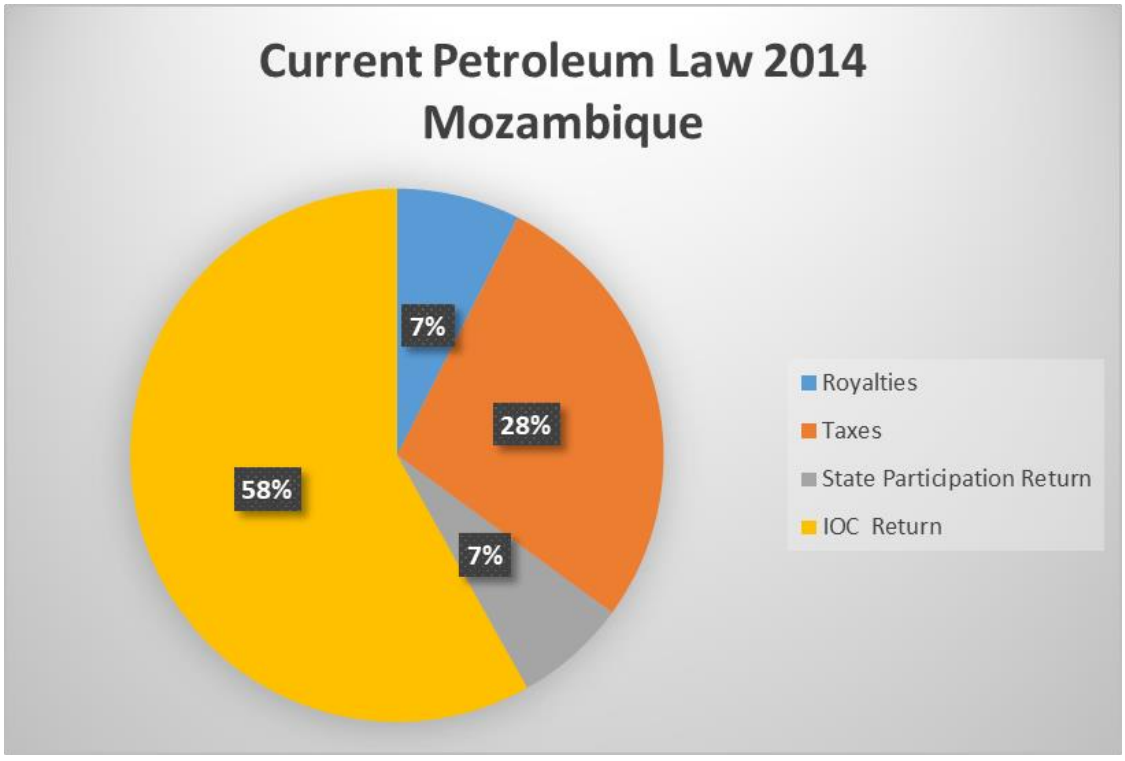

Figure 15: Division of government take in Mozambique royalties, taxes, state return and the return for IOC

4.7 ECONOMIC KEY INDICATORS

According to Swe and Emodi (2018), companies and governments use an objective method of determining the economic worth/profitability of individual investment opportunities. In this regard, having a realistic basis for selection implies there is likely no single measure of profitability that considers all the factors or investment projects

that are relevant to the decision-maker. As a result, a combination of metrics best captures the opportunity's economic worth.

The following section examines how the fiscal regime influences the attractiveness of investment opportunities in SA and Mozambique. These economic indicators do not consider the risk of exploration.

4.7.1 Net present value (NPV) and internal rate of return (IRR)

The calculation results in Tables 9, 10 and 11 are for the three scenarios; two SA scenarios with the current MPRDA 2012 and the proposed MPRDA which is not yet signed into law, as well as the Petroleum Law for Mozambique in comparison. These indicators are shown from the investor's point of view. The results are calculated using the same reserves for both SA and Mozambique. Table 9 shows a summary of the NPV between the host government and the IOC.

Table 9: Economic indicator summary for Scenario 10% state participation

ECONOMICS SUMMARY		
NPV	UNITS	
PROJECT NPV	2385	$MM
IOC NPV	2134	$MM
NOC NPV	251	$MM
IRR	31%	

Table 10: Economic indicator summary for Scenario 20% state participation

ECONOMICS SUMMARY		
NPV		
PROJECT NPV	**2387**	**$MM**
IOC NPV	**1717**	**$MM**
NOC NPV	**670**	**$MM**
IRR	**28%**	

The economic indicators, both NPV and IRR, show that in the current MPRDA Scenario 1, the NPV is 2134 $MM (Table 9), compared to a lower NPV at 1717 $MM (Table 10). This shows that the increase in state participation will deliver a huge decrease in IOC returns. Although both scenarios have a positive NPV, there is also a decrease in IRR between the two scenarios.

Table 11: Economic indicator summary for Mozambique 10% state participation

ECONOMICS SUMMARY		
RESERVES (OIL)	**215.85**	**MBbls**
INDICATORS		
PROJECT NPV	**2321**	**$MM**
IOC NPV	**1831**	**$MM**
State NPV	**490**	**$MM**
IRR	**30%**	

The highest NPV for IOC occurred in the current MPRDA (Scenario 1); however, there is an increase of return for the state with Scenario 2. The results from Table 11 indicate that the current MPRDA and the Petroleum Law NPV for NOC (state participation) are similar and the proposed MPRDA shows an increase in NPV for NOC.

4.8 SUMMARY OF DATA PRESENTATION

The most evident observation from the results in the previous section is that the proposed MPRDA has a higher IOC NPV compared to the current MPRDA. The proposed MPRDA increases the government take, where state participation is increased up to 20%. If the government wants to encourage investors to continue exploration in SA, there needs to be a balance between the profit that companies make and the revenue that government can collect. The results also show that the current state MPRDA and the Petroleum Law in Mozambique are similar, given that Mozambique has higher royalties than SA.

CHAPTER 5: DISCUSSION OF THE RESULTS OR FINDINGS

5.1 INTRODUCTION

This chapter analyses the results from Chapter 4 and assesses the findings concerning the literature review in Chapter 2. The following section is based on a hypothetical model comparing SA's fiscal regime to Mozambique's fiscal regime, to determine whether SA's regulatory/fiscal regime is more appealing for investment in E&P than Mozambique's.

5.2 DISCUSSION OF THE ECONOMIC MODEL

5.2.1 Take statistics

Contractor and government take varied in both scenarios (the current and the proposed fiscal regime). There was an increase in government take when the proposed fiscal regime was assumed. For Mozambique, the Petroleum Law was assumed and the contractor took more revenue (58%) – making the fiscal regime more attractive than both SA scenarios (cf. Figures 12-16, Chapter 4). In all three scenarios, the contractor took all the exploration risk and made a return of 55%; which would likely occur if the proposed MPRDA were promulgated as law.

5.2.2 State and contractor NPVs

To establish how attractive the fiscal regime is, the contractor and state's NPVs for all the scenarios were plotted (Table 10). The major findings for the NPVs were that the NPV for IOC was lowest when the proposed MPRDA was applied, compared to the current MPRDA. The study also shows that Mozambique had higher contractor NPV, making Mozambique more attractive compared to both SA scenarios. Currently, Mozambique and SA are using the concessionary approach, with set royalties for both countries.

Ocran, Broni-Bediako and Ofori-Sarpong (2019) state that the NPV corresponds to field size and product price. A critical aspect of the model shows that investors are attracted to a flexible fiscal system; however, neither country's fiscal system is flexible or negotiable. For example, the proposed MPRDA (Scenario 2), reduces the IOC'S NPV, which works as a disadvantage and is less attractive to the contractor.

The results have shown that the MPRDA and Petroleum Law affect the commerciality of oil and gas. Ocran *et al.* (2019) state that oil and gas markets are becoming the structure and the operation of the global E&P industry, which has changed dramatically in recent years, as the quest for and exploitation of petroleum resources is now primarily motivated by the attractiveness of fiscal regimes rather than geological prospectivity.

The results indicate that before the proposed Bill, SA was more attractive; with the proposed Bill increasing state participation, there is less attractiveness. Mozambique is still shown to be more attractive compared to both SA scenarios with the same economic model assumptions. The results also show that in Mozambique, the project will be more profitable compared to SA – with a higher NPV and IRR.

The results show that the MPRDA has a significant influence on the commerciality of upstream oil and gas development potential. Equity allocated, even to 20%, to the host government is aligned with other oil and gas jurisdictions. However, the free carried interest (of 20%) throughout the project cycle is not as common. A carry of 20% without any financial obligation through the overall project lifecycle is an additional tax imposed on the investor, negatively affecting the returns. This is, therefore, not commensurate with the investment at risk. In the case of Mozambique, the equity allocated is not a free carried and therefore does not have as much negative impact on the investment of the IOC.

The state (SA) is also unlikely to have the funding capacity or risk appetite to undertake high-risk exploration on its own. An environment, therefore, needs to be created where the balance between the state beneficiating from its natural resources, while enabling an investment environment where explorers see sufficient reward to justify the risk they undertake, is enabled through the MPRDA. The importance of SA considering its developmental ambitions, its current capabilities and limited (financial) resources in deciding how to position itself for participation in the oil and gas industry, has been discussed earlier in this document.

It is equally important to recognise that while there are some exciting developments in the SA oil and gas E&P domain (such as deep-water offshore and potential shale gas), SA is by no means seen as an attractive E&P investment environment, and many

global E&P players view SA’s potential as ‘unproven’. A 20% free carry as originally proposed could result in limited or no exploration (investment) activity because there is no commensurate potential return for investors – this scenario has no benefit to the state.

When considering whether to engage in prospects in SA's upstream oil and gas sector, management will pay close attention to key economic factors. Under the terms of the new Bill, the profitability of these possibilities, as well as the number of them that deserve investment, will be drastically decreased.

5.3 CONCLUSION

The most obvious observation from the above results is that the proposed MPRDA has a lower IOC NPV than the current MPRDA; the proposed Bill increases the government share, with state participation increased up to 20%. If the government wants to encourage investors to continue exploring the country, there must be a balance between the profits made by companies and the revenue that the government can collect. The findings also indicate that the current state MPRDA in SA and the Petroleum Law in Mozambique are comparable – even though Mozambique has higher royalties than SA.

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

6.1 INTRODUCTION

This chapter summarises the findings of the study and provides a conclusion concerning the literature reviewed and the hypothetical model. The introduction, literature review, methodology and results presentation were all included in previous chapters. The emphasis of this chapter is on creating a synthesis and drawing conclusions based on the findings.

6.2 CONCLUSIONS

The study focused on defining the evolution of petroleum policy for Mozambique and SA. The SA mineral policy has evolved throughout mining history and political changes. Mineral mining rights were originally legislated under the Minerals Act 50 of 1991. This all changed during the conversion of old-order mining rights to the new order that was brought about by the introduction of the original MPRDA in 2002 The evolution and change of mineral law have addressed the expansion opportunities for historically disadvantaged persons (BBBEE).

Mozambique's policy started in 1986 when the government enacted its first mining legislation. The licensing authority in Mozambique was given the power to enter into agreements for exploration and mining. The mining law was essentially a mechanism that offered basic licensing rights and varying fiscal incentives; the aim was to negotiate information on a case-by-case basis (Coakley, 1998). Mozambique has been very active in the exploration and development of oil and gas. After the discovery of gas in 1960, the Mozambican government reviewed its policies to the current policy, the Petroleum Law. The new Petroleum Law makes more provision for new mining contracts that must provide state participation in all mining operations.

SA has proposed the amended MPRDA which has not been signed into law (MPRDA, 2014) – and the current MPRDA (2002) prevails. The different scenarios that were modelled in the hypothetical model have revealed that the proposed fiscal regime will have a major impact on the contractor (IOC) regarding the profitability of the project. The results have shown that the NPV of the IOC will decrease if the new Bill is implemented and this will influence the attractiveness of the fiscal regime in SA. The

study also shows that in Mozambique, the Petroleum Law is more attractive than the proposed policy but it is similar to the current fiscal regime in SA.

The results show that before the amendment of the Bill with 10% non-carried state participation, SA was more attractive. With the proposed Bill increasing state participation, attractiveness is reduced. Using the same economic model assumptions, Mozambique is still shown to be more attractive than both SA scenarios. The results show that the project will be more profitable in Mozambique, with a higher NPV and IRR, compared to SA.

The summary of the results is as follows:

- Regarding current state participation (10% at development, the state pays its share), three scenarios were run. The rate of return for the scenario of 10% equity is modelled;
- This assumes that OPEX is incurred from the start of development, exploration is carried out, and development and production costs are incurred. As and when the IOC take occurs is about 64% compared to running the model with the status quo parameters. Increasing equity to 20% results in the return to the IOC being decreased to 58%;
- The third scenario is the case of Mozambique where the IOC takes 59% more than the proposed MPRDA and the current MPRDA. Therefore, Mozambique is more attractive than the current SA fiscal regime, which, in turn, is more attractive than the proposed new MPDRA.

SA still has untapped reserves and more room for exploration, which requires the IOC to invest to grow the resources in terms of oil and gas. The results of the study have shown that Mozambique has a more attractive fiscal regime compared to both the proposed and the current MPRDA. The recommendation is for SA to have more negotiable fiscal terms, such that the fiscal system gives adequate compensation to the host government but with more focus on attracting investment.

The findings show that, in SA’s case, there is more than a 20% state carry-over from the exploration. If the state participation is decreased, the fiscal regime will be more attractive for a country where more investment is needed for exploration. Therefore,

negotiations should be made in terms of royalties – depending on the oil price and water depth which make it more expensive to develop. If the Bill is implemented, it will negatively affect the attractiveness of SA as a location for upstream oil and gas investment.

The MPRDA includes several provisions which materially affect the offshore industry from a commercial and financial perspective. Changing the state's 10% participation to a lifetime free carry of 20% increases exploration/development risk and tax take (from the investor perspective). Changing the BBBEE element from 10% to 26% is likely to reduce the size and timing of investor cash flows – if we assume the participants will need to be funded by loans funded by the investor. This case is different if the financing is arranged separately. Resources are owned by SA citizens before and after the MPRDA Bill and should be optimised for their benefit. As drafted, the MPRDA could materially affect the offshore industry as it is critical to unlocking the value of the resource for SA citizens by bringing in investors (IOC) who have the necessary financial resources, technology and skills for this scale of project. The proposed changes negatively affect the viability of E&P from the investor's (IOC's) perspective. The main concern is that SA may miss out on the numerous potential benefits that offshore oil may bring SA – as the results have shown that increased state participation will erode the value of return for the IOC.

6.3 SUMMARY OF THE RETURN PROFILE

The IOC is required to invest first and to take an unfettered exploration risk. For this, the IOC will require a commercial return reflective of the exploration risk (such as the risk that nothing is found or that sub-economic resources are discovered) and the subsequent field development risk. Through the intended lifetime free carry, the state does not take any exploration risk or field development risk. Similarly, the BBBEE party is not intended to take an exploration risk. Regarding field development risk, the

position depends on whether the BBBEE party can secure its funding (at its own risk and cost) or whether it raises funding from a third party IOC or a third-party funder.

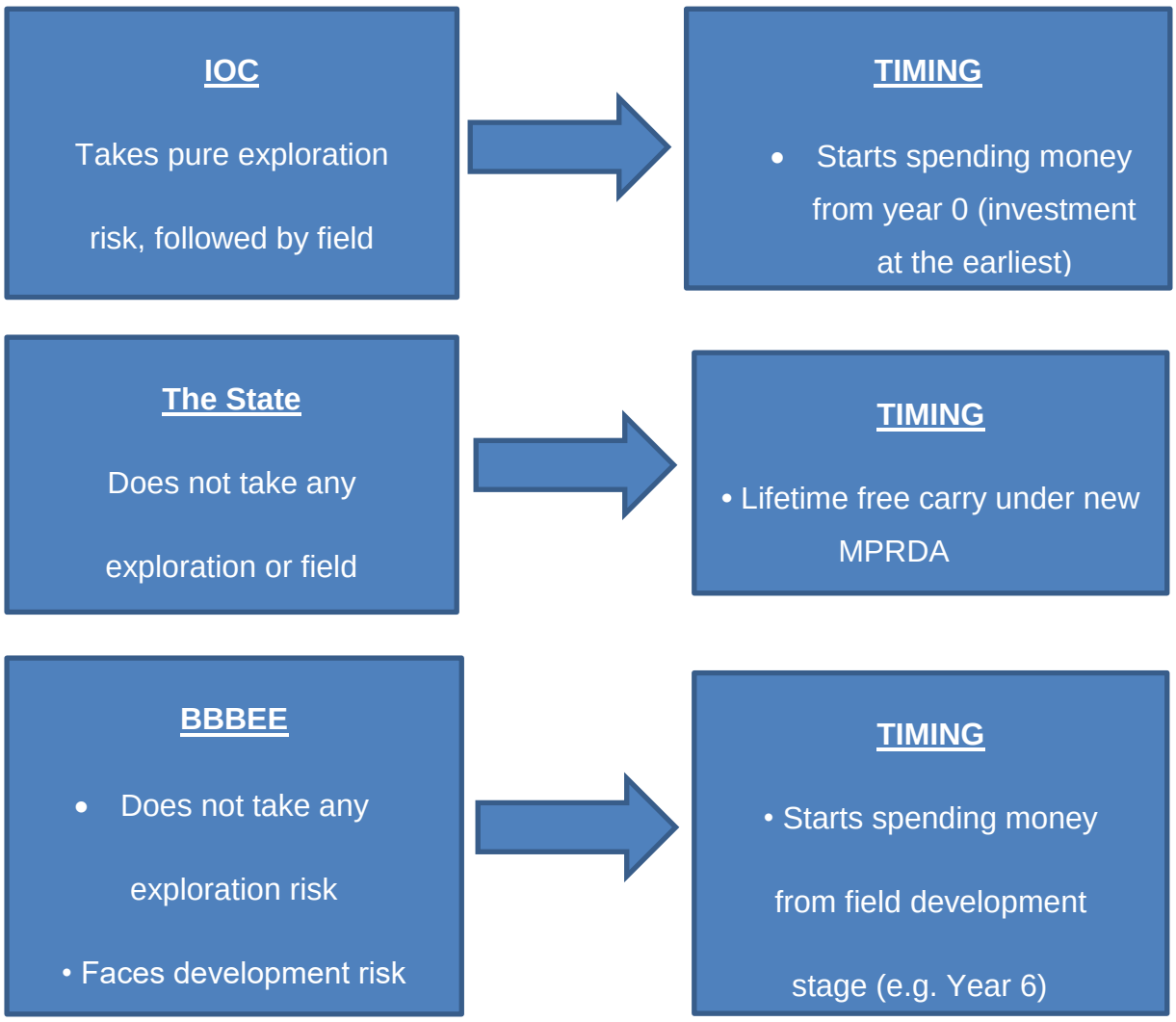

Figure 17: Summary of return profile with the proposed MPRDA (author's observations, MPRDA)

In the case of Mozambique, the fiscal regime is more attractive and there are more producing fields. Mozambique has also shown growth in exploration over the past few years with the change of the Petroleum Law, after the discovery in 2014, to accommodate the country's objectives of increasing E&P. As a guiding framework the Petroleum Law states that any investor interested in exploration must do it in collaboration with Empresa Nacional DE Hidrocarbonetos (ENH), the Mozambique

state representative in the petroleum industry. As a result, ENH will be able to participate in the upstream sector.

6.4 CONTRIBUTION OF THE STUDY TO THE LITERATURE

The study has contributed to literature that would assist a host government to design a fiscal regime that is optimal for attracting investment in E&P. Given that SA has recently increased discovered resources, the study will be more useful to policy-makers for ensuring a fair share of resources. The study could shed some light on mechanisms for monitoring policy evolution and their effect on attracting investment. The study also clarifies the proposed Mineral Petroleum Bill and its effect on attracting investment. The study will help investors to depict commercial and financial concerns of the proposed Bill compared to other countries like Mozambique.

6.5 SUGGESTED FURTHER STUDIES

Studies have shown that the production sharing contract (PSC) system is more attractive than the concessionary system that is used in both SA and Mozambique. As a result, a comparative study of contract structures in the oil and gas E&P industry would be useful in both countries

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APPENDICES

APPENDIX A: INPUT

			Period start	01 Jan 22	01 Jan 23	01 Jan 24	01 Jan 25	01 Jan 26	01 Jan 27	01 Jan 28	01 Jan 29	01 Jan 30	01 Jan 31	01 Jan 32	01 Jan 33	01 Jan 34	01 Jan 35	01 Jan 36	01 Jan 37	01 Jan 38	01 Jan 39	01 Jan 40	01 Jan 41	01 Jan 42	01 Jan 43	01 Jan 44	01 Jan 45	01 Jan 46	01 Jan 47	01 Jan 48	01 Jan 49	01 Jan 50	01 Jan 51	01 Jan 52
Project Timing																																		
Exploratic	*Date*	01 Jan 22																																
Exploratic	*Years*	12.00 years																																
Exploratic	*Date*	**31 Dec 33**																																
Developm	*Date*	**01 Jan 34**																																
Developm	*Years*	4 years																																
Developm	*Date*	**31 Dec 37**																																
Productio	*Date*	**01 Jan 38**																																
Productio	*Years*	**26.00 years**																																
Abandonr	*Date*	**31 Dec 59**																																
nue																																		
Production volumes																																		
Daily Production volumes																																		
Oil	*MBbl/day*		599.6																	85.0	85.0	85.0	75.9	60.2	47.8	37.9	30.1	23.9	18.9	15.0	11.9	9.5	7.5	6.0
Gas	*MMscf/day*		-																															
Condensa	*MBbl/day*		-																															
Production days pe		365 days																																
nditure																																		
Operating Expenses																																		
Operating Costs	**Indexation**																																	
Exploratic	*USD (mil)*	None	63.7	23.0	2.0	1.0	1.0	1.0	25.4	10.3																								
Exploratic	*USD (mil)*	US CPI	10.0								5.0	5.0																						
Fixed Pro	*USD (mil)*	US CPI	1,314.0																	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6
Opex #4	*USD (mil)*	US CPI	-																															
Opex #5	*USD (mil)*	US CPI	-																															
Operator Costs																																		
Manual e	*[select]*	Manual																																
		Indexation / Variable Rate																																
Operator	*USD (mil)*	US CPI	104.5										2.4	2.2	0.5	5.1	6.8	26.1	23.2	5.2	6.9	3.5	1.8	1.8	1.8	1.8	1.8	1.8	3.5	1.8	1.8	1.8	1.8	1.8
Operator	%	2.0%																																
Capital Expenditure																																		
Name of cost		Indexation																																
Exploratic	*USD (mil)*	US CPI	120.0										120.0																					
Appraisal	*USD (mil)*	US CPI	110.0											110.0																				
Feasibilit	*USD (mil)*	US CPI	25.0												25.0																			
Developm	*USD (mil)*	US CPI	3,657.0													255.0	340.0	1,306.0	1,161.0	170.0	255.0	85.0							85.0					
Capex #5	*USD (mil)*	US CPI	-																															
Capex #6	*USD (mil)*	US CPI	-																															
Capex #7	*USD (mil)*	US CPI	-																															
Capex #8	*USD (mil)*	US CPI	-																															
Capex #9	*USD (mil)*	US CPI	-																															
Capex #1	*USD (mil)*	US CPI	-																															
donment																																		
Abandonr	*USD (mil)*	365.0																																
Year incu	*[select]*	**31 Dec 59**																																
Indexatior	*[select]*	US CPI																																

					Period start	01 Jan 22	01 Jan 23	01 Jan 24	01 Jan 25	01 Jan 26	01 Jan 27	01 Jan 28	01 Jan 29	01 Jan 30	01 Jan 31	01 Jan 32	01 Jan 33	01 Jan 34	01 Jan 35	01 Jan 36	01 Jan 37	01 Jan 38	01 Jan 39	01 Jan 40	01 Jan 41	01 Jan 42	01 Jan 43	01 Jan 44	01 Jan 45	01 Jan 46	01 Jan 47	01 Jan 48	01 Jan 49	01 Jan 50	01 Jan 51	01 Jan 52	
					Period end	31 Dec 22	31 Dec 23	31 Dec 24	31 Dec 25	31 Dec 26	31 Dec 27	31 Dec 28	31 Dec 29	31 Dec 30	31 Dec 31	31 Dec 32	31 Dec 33	31 Dec 34	31 Dec 35	31 Dec 36	31 Dec 37	31 Dec 38	31 Dec 39	31 Dec 40	31 Dec 41	31 Dec 42	31 Dec 43	31 Dec 44	31 Dec 45	31 Dec 46	31 Dec 47	31 Dec 48	31 Dec 49	31 Dec 50	31 Dec 51	31 Dec 52	
Project Timing																																					
	Explo	*Date*	01 Jan 22																																		
	Explo	*Years*	12.00 years																																		
	Explo	*Date*	**31 Dec 33**																																		
	Devel	*Date*	**01 Jan 34**																																		
	Devel	*Years*	4 years																																		
	Devel	*Date*	**31 Dec 37**																																		
	Produ	*Date*	**01 Jan 38**																																		
	Produ	*Years*	**-134.00 years**																																		
	Aban	*Date*	**00 Jan 00**																																		
	NPV (	*Date*	01 Jan 15																																		
Revenue																																					
Production volumes																																					
	Daily Production volumes																																				
	Oil	*USD(M*(mil)			36,386.0																	5,158.0	5,158.0	5,158.0	4,605.0	3,654.0	47.8	2,899.0	2,300.0	1,826.0	1,448.0	1,149.0	912.0	547.0	455.0	316.0	
	Gas	*MMscf/day*			-																																
	Cond	*MBbl/day*			-																																
	Total				36,386.0																																
	Production days per		365 days																																		
Expenditure																																					
Operating Expenses																																					
	Operating Costs		**Indexation**																																		
	Explo	*USD (mil)*	None		68.6	23.5	2.1	1.0	1.0	1.0	28.0	12.0																									
	Explo	*USD (mil)*	US CPI		12.0								6.0	6.0																							
	Fixed	*USD (mil)*	US CPI		2,225.0																	126.0	129.0	132.0	135.0	135.0	135.0	141.0	144.0	150.0	154.0	157.0	161.0	164.0	168.0	172.0	
	Opex	*USD (mil)*	US CPI		-																																
	Opex	*USD (mil)*	US CPI		2,306.9																																
						23.5	2.1	1.0	1.0	1.0	28.0	12.0	6.0	6.0																							
Capital Expenditure																																					
	Name of cost		Indexation																																		
	Explo	*USD (mil)*	US CPI		149.2										149.0																						
	Appra	*USD (mil)*	US CPI		139.8											139.0																					
	Feasi	*USD (mil)*	US CPI		32.5												32.0																				
	Devel	*USD (mil)*	US CPI		5,155.7													338.0	461.0	18,010.0	1,644.5	246.0	3,377.0	128.0							85.0						
	Cape	*USD (mil)*	US CPI		-																																
	Cape	*USD (mil)*	US CPI		-																																
	Cape	*USD (mil)*	US CPI		-																																
	Cape	*USD (mil)*	US CPI		-																																
	Cape	*USD (mil)*	US CPI		-																																
	Cape	*USD (mil)*	US CPI		-																																
					54,771																																
Abandonment																																					
Abandoment Cost	mil	USD()			835																																
Expenditure	**to be carried for State 10%**																																				
	Oparator (	*USD (mil)*			0.6																																
	Fixed Cos	*USD (mil)*			8.2																																
	Capex	*USD (mil)*			32.0																																
	Total	*USD (mil)*			41.0																																
		USD (mil)																																			
		USD (mil)																																			
		USD (mil)																																			
		USD (mil)																																			
		USD (mil)																																			
		USD (mil)																																			
Cash Expenditure incurr	**to be carried for**		*USD (mil)*		14.8																																
			USD (mil)		222.0																																
			USD (mil)		515.0																																
			USD (mil)		83.0																																
			USD (mil)		836.0																																
			USD (mil)																																		
			USD (mil)																																		
			USD (mil)																																		
			USD (mil)																																		
			USD (mil)																																		
MPRDA Royalty	**IO**	**0.9**	**USD (mil)**		**32.741**	**-23**	**-2.1**	**-1.1**	**-1.1**	**-28**	**-12**	**-6**	**-6**	**-61**	**-152**	**-152**	**-142**	**-33**	**-310**	**-423**	**-1.66**	**-1.5**	**4.642**	**4.642**	**4.642**	**4.144**	**3.289**	**2.609**	**2.07**	**1.643**	**1.303**	**1.031**	**820**	**650**	**512**		
			USD (mil)																				**4300**	**4177**	**4177**	**4020**	**3162**	**2479**	**11937**	**1507**	**1.165**	**755**	**676**	**503**	**365**		
Royalty Rate		0.005	0.05	12.5																																	
			USD (mil)			*0*	0	00 Jan 00	0	0	0	*0*	0	00 Jan 00	0	0	0	*0*	0	00 Jan 00	0	0	0.005	*0.05*													
Toatal Royalty			USD (mil)		1218																																
			USD (mil)																																		
			USD (mil)																																		
			USD (mil)																																		
			USD (mil)																																		
			USD (mil)																																		
MPRDA State Participation					3.638																																
																		-34	-47	-184	-167	512	515	515	515	460	365	290	230	182	144	114	91.2	72.4	57.4	45.6	36
																						477	**499**	**464**	**489**	**446**	**351**	**275**	**215**	**167**	**129**	**86**	**75**	**56**	**40**	**28**	**18**
	Royalty Rate	**0.01**	**0.05**	**12.5**																				**0.005**	**0.005**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0**

								Period start	01 Jan 22	01 Jan 23	01 Jan 24	01 Jan 25	01 Jan 26	01 Jan 27	01 Jan 28	01 Jan 29	01 Jan 30	01 Jan 31	01 Jan 32	01 Jan 33	01 Jan 34	01 Jan 35	01 Jan 36	01 Jan 37	01 Jan 38	01 Jan 39	01 Jan 40	01 Jan 41	01 Jan 42	01 Jan 43	01 Jan 44	01 Jan 45	01 Jan 46	01 Jan 47	01 Jan 48	01 Jan 49	01 Jan 50	01 Jan 51	01 Jan 52
								Period end	31 Dec 22	31 Dec 23	31 Dec 24	31 Dec 25	31 Dec 26	31 Dec 27	31 Dec 28	31 Dec 29	31 Dec 30	31 Dec 31	31 Dec 32	31 Dec 33	31 Dec 34	31 Dec 35	31 Dec 36	31 Dec 37	31 Dec 38	31 Dec 39	31 Dec 40	31 Dec 41	31 Dec 42	31 Dec 43	31 Dec 44	31 Dec 45	31 Dec 46	31 Dec 47	31 Dec 48	31 Dec 49	31 Dec 50	31 Dec 51	31 Dec 52
	Project Timing							
		Exploration Start		Date		01 Jan 22		
		Exploration length		Years		12.00 years		
		Exploration End		Date		**31 Dec 33**		
		Development Start		Date		**01 Jan 34**		
		Development length		Years		4 years		
		Development end		Date		**31 Dec 37**		
		Production start		Date		**01 Jan 38**		
		Production length		Years		**-134.00 years**		
		Abandonment		Date		**00 Jan 00**		
		NPV date		Date		01 Jan 15		
Revenue								
	Production volumes							
		Daily Production volumes						
		Oil		USD(MIL	(mil)			36,386.0																	5,158.0	5,158.0	5,158.0	4,605.0	3,654.0	47.8	2,899.0	2,300.0	1,826.0	1,448.0	1,149.0	912.0	547.0	455.0	316.0
		Gas		MMscf/day				-
		Condensate		MBbl/day				-
		Total						36,386.0
		Production days per annum				365 days		
Expenditure								
	Operating Expenses							
		Operating Costs				**Indexation**		
		Exploration Opex (pre-2015)		USD (mil)		None		68.6	23.5	2.1	1.0	1.0	1.0	28.0	12.0
		Exploration Opex (forecast)		USD (mil)		US CPI		12.0								6.0	6.0
		Fixed Production OPEX		USD (mil)		US CPI		2,225.0																	126.0	129.0	132.0	135.0	135.0	135.0	141.0	144.0	150.0	154.0	157.0	161.0	164.0	168.0	172.0
		Opex #4		USD (mil)		US CPI		-
		Opex #5		USD (mil)		US CPI		2,306.9
									23.5	2.1	1.0	1.0	1.0	28.0	12.0	6.0	6.0
	Operator Costs							
		Manual entry or % of expenditure		[select]		Manual		
						Indexation / Variable Rate		
		Operator Costs manually entered		USD (mil)		US CPI		104.5										2.4	2.2	0.5	5.1	6.8	26.1	23.2	5.2	6.9	3.5	1.8	1.8	1.8	1.8	1.8	1.8	3.5	1.8	1.8	1.8	1.8	1.8
		Operator Costs as % of expenditure		%		2.0%		
	Capital Expenditure							
		Name of cost				Indexation		
		Exploration Well		USD (mil)		US CPI		149.2										149.0
		Appraisal Well		USD (mil)		US CPI		139.8											139.0
		Feasibility FEED		USD (mil)		US CPI		32.5												32.0
		Development Wells / Facilities		USD (mil)		US CPI		5,155.7													338.0	461.0	18,010.0	1,644.5	246.0	3,377.0	128.0							85.0
		Capex #5		USD (mil)		US CPI		-
		Capex #6		USD (mil)		US CPI		-
		Capex #7		USD (mil)		US CPI		-
		Capex #8		USD (mil)		US CPI		-
		Capex #9		USD (mil)		US CPI		-
		Capex #10		USD (mil)		US CPI		-
								54,771
Abandonment								
Abandonment Cost			mil	USD()				835
Expenditure		**to be carried for State 10%**				20%		
			Oparator Cost		USD (mil)			0.6
			Fixed Cost		USD (mil)			8.2
			Capex		USD (mil)			32.0
			Total		USD (mil)			41.0
					USD (mil)			
					USD (mil)			
					USD (mil)			
					USD (mil)			
					USD (mil)			
					USD (mil)			
	Cash Expenditure incurred by state		**to be carried for State 10%**			USD (mil)		14.8
						USD (mil)		222.0
						USD (mil)		515.0
						USD (mil)		83.0
						USD (mil)		836.0
						USD (mil)		
						USD (mil)		
						USD (mil)		
						USD (mil)		
						USD (mil)		
	MPRDA Royalty		**IOC**	**80%**		**USD (mil)**		**29,108**	**-23**	**-2.1**	**-1.1**	**-1.1**	**-28**	**-12**	**-6**	**-6**	**-61**	**-152**	**-152**	**-142**	**-33**	**-310**	**-423**	**-1.66**	**-1.5**	**4.642**	**4.642**	**4.642**	**4.144**	**3.289**	**2.609**	**2.07**	**1.643**	**1.303**	**1.031**	**820**	**650**	**512**	
						USD (mil)																				**4300**	**4177**	**4177**	**4020**	**3162**	**2479**	**11937**	**1507**	**1.165**	**755**	**676**	**503**	**365**	
	Royalty Rate			0.005		0.05	13	
						USD (mil)		
	Toatal Royalty					USD (mil)		1,083
						USD (mil)		
						USD (mil)		
						USD (mil)		
						USD (mil)		
						USD (mil)		
	MPRDA State Participation							7,277
																					-34	-47	-184	-167	512	515	515	515	460	365	290	230	182	144	114	91.2	72.4	57.4	45.6
																									477	**499**	**464**	**489**	**446**	**351**	**275**	**215**	**167**	**129**	**86**	**75**	**56**	**40**	**28**
		Royalty Rate			**0.005**	**0.05**	**13**																				**0.005**	**0.005**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**

APPENDIX B: SCENARIO 1 CALCULATIONS

DA Royalty					
Royalty determination - JV Partners					
Revenue	*USD (mil)*	90%			32,747.5
EBIT (for Royalty purposes)	*USD (mil)*				24,811.2
MPRDA Royalty rate	%	0.5%	5.0%	12.5	
Additional State participation royalty	%	0%			
All-In Royalty Rate					
Total royalty	*USD (mil)*				1,218.3
Royalty determination - State Participation					
Revenue	*USD (mil)*	10%			3,638.6
EBIT (for Royalty purposes)	*USD (mil)*				2,802.3
MPRDA Royalty rate	%	0.5%	5.0%	12.5	
Additional State participation royalty	%	0%			
All-In Royalty Rate					
Total royalty	*USD (mil)*				135.4

Taxation for State Participation (excl Carried Expenditure)			
Taxable Income			
Revenue	*USD (mil)*	10%	3,638.6
MPRDA Royalty	*USD (mil)*		-135.4
Operator Costs	*USD (mil)*		-15.4
Fixed operating expenses	*USD (mil)*		-230.7
Capital expenditure	*USD (mil)*		-547.7
Abandonment costs	*USD (mil)*		-83.5
Carried Operator Costs	*USD (mil)*		0.6
Carried Fixed operating expenses	*USD (mil)*		8.2
Carried Capital expenditure	*USD (mil)*		32.1
Carried Abandonment Costs	*USD (mil)*		-
Interest on Rolled Expenditure Loan	*USD (mil)*		-
Taxable income before uplift	*USD (mil)*		2,667.0
Schedule 10 tax uplift	*USD (mil)*		
Exploration Capex	*USD (mil)*	100%	-
Post-exploration Capex	*USD (mil)*	50%	-257.8
Taxable income after uplift	*USD (mil)*		2,409.2
Assessed Loss			
Assessed loss brought forward	*USD (mil)*		
Increase in assessed losses	*USD (mil)*		730.1
Utilisation of assessed losses	*USD (mil)*		-646.6
Assessed loss carried forward	*USD (mil)*		
Tax Payable			
Taxable income after assessed losses	*USD (mil)*		2,492.6
Tax cash payable	*USD (mil)*	28.00%	697.9

Taxation for JV Partners

Taxable Income

Revenue	*USD (mil)*	90%	32,747.5
Interest on Rolled Expenditure Loan	*USD (mil)*		-
MPRDA Royalty	*USD (mil)*		-1,218.3
Operator Costs	*USD (mil)*		-138.6
Fixed operating expenses	*USD (mil)*		-2,076.2
Capital expenditure	*USD (mil)*		-4,929.4
Abandonment costs	*USD (mil)*		-751.1
Carried Operator Costs	*USD (mil)*		-0.6
Carried Fixed operating expenses	*USD (mil)*		-8.2
Carried Capital expenditure	*USD (mil)*		-32.1
Carried Abandonment costs	*USD (mil)*		-
Taxable income before uplift	*USD (mil)*		23,592.9
Schedule 10 tax uplift			
Exploration Capex	*USD (mil)*	100%	-321.4
Post-exploration Capex	*USD (mil)*	50%	-2,320.1
Taxable income after uplift	*USD (mil)*		20,951.5

Assessed Loss

Assessed loss brought forward	*USD (mil)*		
Increase in assessed losses	*USD (mil)*		7,301.7
Utilisation of assessed losses	*USD (mil)*		-6,550.7
Assessed loss carried forward	*USD (mil)*		

Tax Payable

Taxable income after assessed losses	*USD (mil)*		21,702.5
Tax cash payable	*USD (mil)*	28.00%	6,076.7

APPENDIX C: SCENARIO 2

Royalty determination - JV Partners					
Revenue	*USD (mil)*	80%			29,108.8
EBIT (for Royalty purposes)	*USD (mil)*				20,336.3
MPRDA Royalty rate	%	0.5%	5.0%	12.5	
Additional State participation royalty	%	0%			
All-In Royalty Rate					
Total royalty	*USD (mil)*				893.5

Royalty determination - State Participation					
Revenue	*USD (mil)*	20%			7,277.2
EBIT (for Royalty purposes)	*USD (mil)*				7,277.2
MPRDA Royalty rate	%	0.5%	5.0%	12.5	
Additional State participation royalty	%	0%			
All-In Royalty Rate					
Total royalty	*USD (mil)*				363.9

Taxable income IOC

Taxable Income			
Revenue	*USD (mil)*	80%	29,108.8
Interest on Rolled Expenditure Loan	*USD (mil)*		-
MPRDA Royalty	*USD (mil)*		-893.5
Operator Costs	*USD (mil)*		-123.2
Fixed operating expenses	*USD (mil)*		-1,845.5
Capital expenditure	*USD (mil)*		-4,381.7
Abandonment costs	*USD (mil)*		-667.6
Carried Operator Costs	*USD (mil)*		-30.8
Carried Fixed operating expenses	*USD (mil)*		-461.4
Carried Capital expenditure	*USD (mil)*		-1,095.4
Carried Abandonment costs	*USD (mil)*		-166.9
Taxable income before uplift	*USD (mil)*		19,442.9
Schedule 10 tax uplift			
Exploration Capex	*USD (mil)*	100%	-321.4
Post-exploration Capex	*USD (mil)*	50%	-2,577.9
Taxable income after uplift	*USD (mil)*		16,543.6
Assessed Loss			
Assessed loss brought forward	*USD (mil)*		
Increase in assessed losses	*USD (mil)*		8,031.8
Utilisation of assessed losses	*USD (mil)*		-7,197.3
Assessed loss carried forward	*USD (mil)*		
Tax Payable			
Taxable income after assessed losses	*USD (mil)*		17,378.1
Tax cash payable	*USD (mil)*	28.00%	4,865.9

Taxation for State Participation (excl Carried Expenditure)			
Taxable Income			
Revenue	*USD (mil)*	20%	7,277.2
MPRDA Royalty	*USD (mil)*		-363.9
Operator Costs	*USD (mil)*		-30.8
Fixed operating expenses	*USD (mil)*		-461.4
Capital expenditure	*USD (mil)*		-1,095.4
Abandonment costs	*USD (mil)*		-166.9
Carried Operator Costs	*USD (mil)*		30.8
Carried Fixed operating expenses	*USD (mil)*		461.4
Carried Capital expenditure	*USD (mil)*		1,095.4
Carried Abandonment Costs	*USD (mil)*		166.9
Interest on Rolled Expenditure Loan	*USD (mil)*		-
Taxable income before uplift	*USD (mil)*		6,913.4
Schedule 10 tax uplift	*USD (mil)*		
Exploration Capex	*USD (mil)*	100%	-
Post-exploration Capex	*USD (mil)*	50%	-
Taxable income after uplift	*USD (mil)*		6,913.4
Assessed Loss			
Assessed loss brought forward	*USD (mil)*		
Increase in assessed losses	*USD (mil)*		-
Utilisation of assessed losses	*USD (mil)*		-
Assessed loss carried forward	*USD (mil)*		
Tax Payable			
Taxable income after assessed losses	*USD (mil)*		6,913.4
Tax cash payable	*USD (mil)*	28.00%	1,935.7

Cash flows to JV Partners

Revenue		80%	
JV participation share of Revenue	*USD (mil)*		29,108.8
JV share of MPRDA Royalty	*USD (mil)*		-893.5
Net revenue cash flows	*USD (mil)*		28,215.4
Expenditure			
JV participation share of Expenditure	*USD (mil)*		-7,018.0
Deduct: JV carry of State Participation Expenditure	*USD (mil)*		-1,754.5
Cash flows after expenditure	*USD (mil)*		19,442.9
Taxation			
Normal tax payable (Schedule 10)	*USD (mil)*		-4,865.9
Cash flows after tax	*USD (mil)*		14,577.0
Expenditure rolled for state			
Expenditure rolled	*USD (mil)*		-
Expenditure repaid by State plus interest	*USD (mil)*		-
Net cash flows to JV Partners	*USD (mil)*		14,577.0

State Revenue

Revenue		20%	
State participation share of Revenue	*USD (mil)*		7,277.2
State participation share of MPRDA Royalty	*USD (mil)*		-363.9
Net revenue cash flows	*USD (mil)*		6,913.4
Expenditure			
State participation share of Expenditure	*USD (mil)*		-1,754.5
Add back: JV carry of State Participation Expenditure	*USD (mil)*		1,754.5
Cash flows after expenditure	*USD (mil)*		6,913.4
Taxation			
Normal tax payable (Schedule 10)	*USD (mil)*		-1,935.7
Cash flows after tax	*USD (mil)*		4,977.6
Expenditure rolled for state			
Expenditure rolled	*USD (mil)*		-
Expenditure repaid by State plus interest	*USD (mil)*		-
Net cash flows to State	*USD (mil)*		4,977.6

APPENDIX D: SCENARIO 3 CALCULATIONS

Returns to JV Partners				
Exploration Phase Cash flows to / (from) JV partners	*USD (mil)*			
Post-Exploration Phase Cash flows to / (from) JV part	*USD (mil)*			
All-In Cash flows to / (from) JV partners	*USD (mil)*			-0.0000001
All-In Internal rate of return	*%*			28.7%
All-In Net present value at Project start	*USD (mil)*	01 Jan 22	10.0%	1,806.5

Exploration Phase Cash flows to / (from) the State	*USD (mil)*			
Post-Exploration Phase Cash flows to / (from) the Sta	*USD (mil)*			
All-In Cash flows to / (from) the State	*USD (mil)*			-0.0000001
Internal rate of return	*%*			286.3%
All-In Net present value at Project start	*USD (mil)*	01 Jan 22	10.0%	710.4

Cash flows to JV Partners

Revenue		80%	
JV participation share of Revenue	*USD (mil)*		29,108.8
JV share of MPRDA Royalty	*USD (mil)*		-893.5
Net revenue cash flows	*USD (mil)*		28,215.4
Expenditure			
JV participation share of Expenditure	*USD (mil)*		-7,018.0
Deduct: JV carry of State Participation Expenditure	*USD (mil)*		-1,754.5
Cash flows after expenditure	*USD (mil)*		19,442.9
Taxation			
Normal tax payable (Schedule 10)	*USD (mil)*		-4,865.9
Cash flows after tax	*USD (mil)*		14,577.0
Expenditure rolled for state			
Expenditure rolled	*USD (mil)*		-
Expenditure repaid by State plus interest	*USD (mil)*		-
Net cash flows to JV Partners	*USD (mil)*		14,577.0

Revenue		20%	
State participation share of Revenue	*USD (mil)*		7,277.2
State participation share of MPRDA Royalty	*USD (mil)*		-363.9
Net revenue cash flows	*USD (mil)*		6,913.4
Expenditure			
State participation share of Expenditure	*USD (mil)*		-1,754.5
Add back: JV carry of State Participation Expenditure	*USD (mil)*		1,754.5
Cash flows after expenditure	*USD (mil)*		6,913.4
Taxation			
Normal tax payable (Schedule 10)	*USD (mil)*		-1,935.7
Cash flows after tax	*USD (mil)*		4,977.6
Expenditure rolled for state			
Expenditure rolled	*USD (mil)*		-
Expenditure repaid by State plus interest	*USD (mil)*		-
Net cash flows to State	*USD (mil)*		4,977.6
Check			-

Cash flows to JV Partners

Revenue		80%	
JV participation share of Revenue	*USD (mil)*		29,108.8
JV share of MPRDA Royalty	*USD (mil)*		-893.5
Net revenue cash flows	*USD (mil)*		28,215.4
Expenditure			
JV participation share of Expenditure	*USD (mil)*		-7,018.0
Deduct: JV carry of State Participation Expenditure	*USD (mil)*		-1,754.5
Cash flows after expenditure	*USD (mil)*		19,442.9
Taxation			
Normal tax payable (Schedule 10)	*USD (mil)*		-4,865.9
Cash flows after tax	*USD (mil)*		14,577.0
Expenditure rolled for state			
Expenditure rolled	*USD (mil)*		-
Expenditure repaid by State plus interest	*USD (mil)*		-
Net cash flows to JV Partners	*USD (mil)*		14,577.0

Revenue		20%	
State participation share of Revenue	*USD (mil)*		7,277.2
State participation share of MPRDA Royalty	*USD (mil)*		-363.9
Net revenue cash flows	*USD (mil)*		6,913.4
Expenditure			
State participation share of Expenditure	*USD (mil)*		-1,754.5
Add back: JV carry of State Participation Expenditure	*USD (mil)*		1,754.5
Cash flows after expenditure	*USD (mil)*		6,913.4
Taxation			
Normal tax payable (Schedule 10)	*USD (mil)*		-1,935.7
Cash flows after tax	*USD (mil)*		4,977.6
Expenditure rolled for state			
Expenditure rolled	*USD (mil)*		-
Expenditure repaid by State plus interest	*USD (mil)*		-
Net cash flows to State	*USD (mil)*		4,977.6

Cash flows to SA Inc.

MPRDA Royalties	*USD (mil)*	1,257.3
Tax from JV Partners	*USD (mil)*	4,865.9
Tax from State Participation (via PetroSA)	*USD (mil)*	1,935.7
Profits from State Participation (via PetroSA)	*USD (mil)*	4,977.6
Net cash flows to SA Inc	*USD (mil)*	13,036.6

Returns to JV Partners

Exploration Phase Cash flows to / (from) JV partners	*USD (mil)*			
Post-Exploration Phase Cash flows to / (from) JV part	*USD (mil)*			
All-In Cash flows to / (from) JV partners	*USD (mil)*			-0.0000001
All-In Internal rate of return	*%*			30.8%
All-In Net present value at Project start	*USD (mil)*	01 Jan 22	10.0%	1,983.8