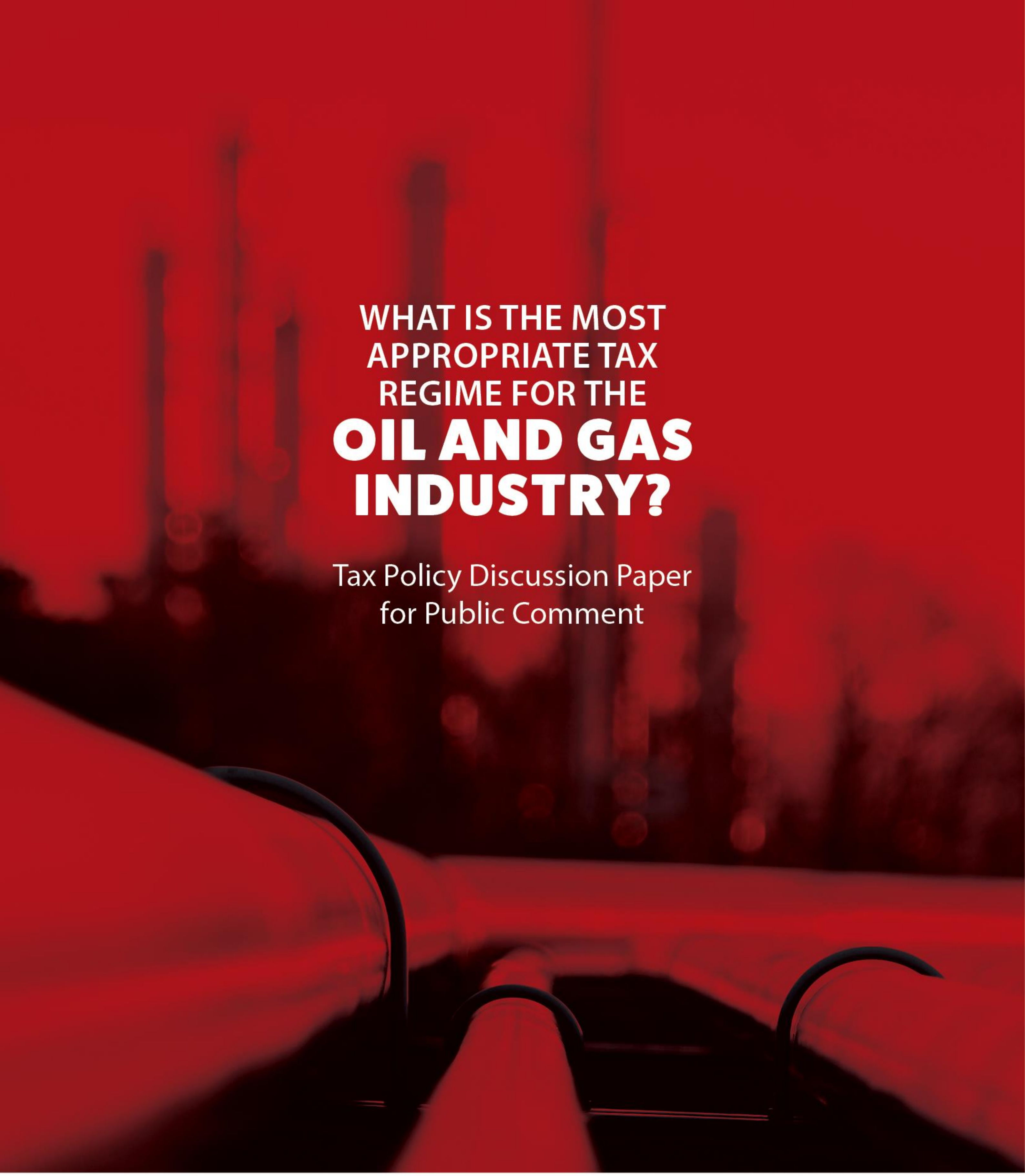

WHAT IS THE MOST APPROPRIATE TAX REGIME FOR THE OIL AND GAS INDUSTRY?

Tax Policy Discussion Paper for Public Comment

national treasury

Department:
National Treasury
REPUBLIC OF SOUTH AFRICA

2030 NDP

STAY SAFE
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Executive Summary

Government wishes to evaluate whether the tax regime for the upstream petroleum industry (within the wider fiscal policy context) is suitably designed to create a balance between attracting investment and generating an appropriate level of government revenue, while simultaneously enabling South Africa to achieve its commitments in respect of climate change. This policy discussion paper reviews the tax treatment of oil and gas activities first announced in the 2019 Budget Review, and seeks public comment.

This discussion document follows the tabling of the Upstream Petroleum Resources Development (UPRD) Bill in Parliament on 1 July 2021 by the Minister of Mineral Resources and Energy. It provides an update on Government's thinking on the tax regime for oil and gas – relative to 2006 when it was first introduced into the Income Tax Act, and before the adoption of policies to deal with climate change.

At the outset, it is important to state that Government values and understands the importance of certainty and transparency for investors. It is within this spirit that this discussion paper is being published for public comment. This document aims to lay the foundation for working towards a tax regime that is adaptive to changing circumstances and complementary to the UPRD Bill, so that investors have a clear understanding of the overall fiscal terms. It also seeks to invite investors' views on its content so that – collectively – we can ensure we have a regime where both government and investors gain a fair share, while promoting appropriate management of our finite and non-renewable oil and gas resources and taking into account our commitments to address climate change and other pertinent environmental challenges.

There will always be differing perspectives on what constitutes a fair share for government and investors. The intent is to ensure that both investors and the people of South Africa gain a balanced share from oil and gas exploration.

The discussion document explores the context (in addition to the fiscal regime) that shapes investment decisions in upstream oil and gas – namely geological certainty (the extent of estimated and known reserves, and the viability of extracting them); oil and gas prices; and climate change and other environmental considerations.

Global commitments to accelerate efforts to transition the energy sector were reaffirmed at the recent 26th Meeting of the Conference of Parties (COP26) under the United Nations Framework Convention on Climate Change (UNFCCC). The Glasgow Climate Pact requires countries to "*transition towards low-emission energy systems, including by rapidly scaling up the deployment of clean power generation and energy efficiency measures, including accelerating efforts towards the phasedown of unabated coal power and phase-out of inefficient fossil fuel subsidies*". It further recognises the need for support for a just transition and targeted support to the poor and most vulnerable based on national circumstances.

As a top 20 emitter of greenhouse gas emissions globally, South Africa made commitments under the 2015 Paris Climate Agreement to further reduce our greenhouse gas emissions and to contribute to global efforts to limit warming to well below 2°c above pre-industrial levels and to pursue efforts to achieve the 1,5°c temperature goal. Our commitments are set out in the 2nd and 3rd Nationally Determined Contributions (NDCs) submitted to the UNFCCC at the COP26 meeting. This requires a peaking of our greenhouse gas emissions in 2025 in the range of 398 to 510 Megatonnes (Mt) and a sharp decline in emissions from 2026 onwards in the range of 350 to 420Mt. A rapid and significant decline in greenhouse gas emissions from the energy sector, in particular from electricity generation and liquid fuels, will therefore be necessary.

A carbon tax was implemented in June 2019 and, combined with other climate policies, it is integral to achieving our NDC commitments in an economically efficient manner. Announcements on the design of the carbon tax for the 2nd phase from 1 January 2023 will be made in Budget 2022 taking into account South Africa's in principle commitment to a net zero emissions pathway by 2050 and the imminent implementation of carbon border adjustments on carbon intensive exports.

This discussion document does not fully consider stronger measures that may be required to deal with climate change – including whether and to what extent oil and gas will be a transitional fuel and source of energy, and for how long. South Africa is in the process of determining further measures to achieve its NDCs, including to what extent gas could act as a transitional fuel and energy source in relation to coal. These are issues that will need to considered in the tax regime for fossil fuels, and to ensure consistency with the future development of the carbon tax as it is revised for its next phase.

Government is seeking to balance the need to invest in less carbon-intensive transition fuels with providing a fiscal and tax regime that is attractive enough for companies to explore for and produce oil and gas, but at the same time avoids incentivising assets that could be stranded due to stricter climate commitments and environmental regulations. While gas is a fossil fuel, its emissions are around 50 per cent less than coal and it could act as an important transition fuel as the economy transforms and shifts to lower-carbon, renewable and energy efficient technologies. This would also help to facilitate a just transition to a lower-carbon economy and ensure energy security of supply and affordable energy that is accessible by all.

The document provides an overview of an array of fiscal regimes and fiscal instruments used worldwide in this industry. The current tax regime for the upstream oil and gas sector in South Africa is relatively generous when compared to other countries. This is evident from a global comparison of 86 countries and is noted by external parties, such as the IMF and private sector.

History has shown that many governments have changed their regimes in response to both fluctuations in commodity prices and significant discoveries. This behaviour understandably causes hesitation on the part of investors to sink substantial capital. If the people of South Africa and investors are to reap the maximum benefits from our oil and gas resources, then a fair, transparent, efficient, as simple as possible, and certain fiscal regime is important.

The type of fiscal regime matters. Currently, South Africa has a concessionary regime – meaning that taxes and royalties are imposed. However, production sharing contracts are a common occurrence globally. In these arrangements, the government will typically enter into a unique contract with each investor, which can make the overall fiscal regime of a country opaque. The UPRD Bill refers to a carried interest enabling the State to retrieve its proportionate share of production, reduced by the portion of costs recoverable by investors. This is effectively a production sharing regime.

It is important to recognise that there might be some challenges that can arise from this type of arrangement. Doing so is imperative so as to minimise the risk of their occurrence. Some of the potential issues are discussed, but most of them are remedied by the UPRD Bill. For example, the benefit of specifying the State's carried interest in legislation is that the regime is transparent and all investors will be treated equally – two important principles in good tax policy design.

Government considered a number of options to revise the tax regime. The analysis included an international comparison for benchmarking (but also recognizing that countries have different geological and political contexts); recommendations from the IMF and Davis Tax Committee; an economic modelling exercise and consideration of key tax policy design principles.

The modelling exercise is based on best-guess estimates for oil and gas reserves from the Petroleum Agency of South Africa (PASA). It compares the estimated outcome of the UPRD Bill (for government and investors) to the estimated outcomes if the tax burden is increased – for example, by introducing a flat-rate royalty; increasing the minimum and maximum rates of the current royalty[1] rate range (which is determined by profitability); removing the capital uplift allowances (investors can currently deduct up to double what they spend); and combinations of these. A sensitivity analysis is included to show estimated net present values (NPVs) under two different cost and reserve assumptions. Using an oil price ranging between USD 40 and USD 80, the modelling exercise shows that net present values (NPVs) swing from negative to positive depending on cost and reserve assumptions under the different fiscal regime options.

Each of the tax instruments is discussed towards the end of the paper, with an indication of Government's stance on each. The tax instruments and variations of current tax instruments (for oil and gas specifically) considered include a resource rent tax; a flat-rate royalty; increased variable royalty rates; reduced capital uplift allowances; and an increased dividends tax rate.

One option is to retain the current tax regime given that government's share is already enhanced with the changes brought in by the UPRD Bill. It is important that this increase in government's share translate into tangible benefits for the people of South Africa. For this to happen, the State's proportionate share of production (reduced by its proportionate share of costs) must flow to the National Revenue Fund.

Based on the economic analysis in the modelling exercise (which included a number of different tax regime options); key tax principles; and considering other countries' fiscal regimes alongside their geology and proven reserves, comments are sought on the following proposal:

- Instead of the variable royalty rate, it is proposed that royalties for the oil and gas industry have a flat rate of 5 per cent applied to gross sales as defined in the Minerals and Petroleum Resources Royalty Act, 2008;
- no changes to the capital allowances applicable to oil and gas companies;
- no petroleum resource rent tax;
- no changes to the withholding taxes applicable to oil and gas companies; and
- the State's 20 per cent share of production / revenue must be channeled to the National Revenue Fund for the benefit of all South Africans. National Treasury and the DMRE will continue to discuss

[1] All references to the current royalty regime in this document refer to the royalty regime in terms of the Mineral and Petroleum Resources Royalty Act of 2008.

the financial and institutional arrangements for the National Petroleum Company.

The proposal for the oil and gas royalty appears feasible from the analysis conducted and is seen as the optimal way forward for three main reasons:

- The three main fiscal instruments – production sharing, corporate income tax and current royalties – are all based on profitability. This means that the State would not yield any benefit for the initial years of production even though a finite resource is being extracted. For this reason, a flat-rate royalty is preferable as the rate would be applied to sales rather than based on profitability. It would mean revenue for Government from the start of production.

- The minimum rate of 0.5 per cent is low by comparison to other countries. The Davis Tax Committee and the IMF have suggested a flat royalty rate of at least 5 per cent on the gross value of production at the delivery point from offshore field facilities.

- The IMF, mining companies and the South African Revenue Service have recognised that the current royalty formula is complex and not suited to the oil and gas industry. A flat-rate royalty would add simplicity to the fiscal regime for oil and gas.

The economic analysis shows that trying to increase the tax take by any other means would reduce the attractiveness of South Africa as an investment destination for upstream petroleum exploration. Given South Africa's NDC commitments and rapid emission reductions required by 2030, and the global commitment to reduce reliance on coal and phase out inefficient fossil fuel subsidies, the extraction of gas could assist in South Africa's just transition to cleaner means of producing electricity.

The document aims to invite discussion among key stakeholders in respect of the proposals; the impact of climate change on this industry; how best should the tax system treat future fossil fuel investments; and the questions posed in relation to fiscal stability agreements.

National Treasury and the Department of Mineral Resources and Energy welcome comments from interested parties. Please send comments to hayley.reynolds@treasury.gov.za and 2022AnnexCProp@treasury.gov.za by **25 January 2022**. These comments may be made public. Please clearly indicate in your submission if you prefer your comments to remain confidential. A public workshop will be held to which all commentators will be invited.

1. Introduction

Oil and gas exploration and production is currently regulated under the Mineral and Petroleum Resources Development Act, 2002 (MPRDA). On 24 December 2019, the Draft Upstream Petroleum Resources Development Bill was published. This intends to replace the relevant sections pertaining to upstream petroleum activities in the MPRDA. Following a public consultation process, the Minister of Mineral Resources and Energy tabled the Upstream Petroleum Resources Development (UPRD) Bill in Parliament on 1 July 2021.

The draft bill included references to fiscal instruments, such as a resource rent tax and production bonus. Government (via collaboration between the National Treasury and the Department of Mineral Resources and Energy) has removed reference to such instruments, retaining only those already included in the Income Tax Act and the Mineral and Petroleum Resources Royalty Act, 2008.

This discussion document discusses the fiscal elements of the oil and gas regime, with a focus on tax policy. Government's objective is to determine whether the tax regime is still suitable for exploring and producing oil and gas in South Africa, while balancing the need for sufficient Government revenue and working towards South Africa's commitments in respect of climate change.

The current tax regime for the upstream oil and gas sector in South Africa is relatively generous when compared to other countries. This is evident from a global comparison of 86 countries and is noted by external parties, such as the IMF[2] and private sector[3]. For example, the uplifts available for capital expenditure are higher than most countries and dividends tax is reduced to zero per cent. These cannot be considered in isolation though. It is important to consider the entire fiscal regime, as well as other factors influencing investment in this industry, to assess the relative attractiveness of the fiscal regime and whether the current regime is suitably designed for the benefit of the people of South Africa.

The current regime was introduced in 2006[4]. At the time, there was uncertainty regarding the pending termination of the OP 26 regime and some companies were postponing investment. Exploration in the 30-year period prior to 2006 revealed small (in comparison to global and regional standards) offshore deposits in the south and west. Yet, a few companies remained interested in the region – most likely due to high oil prices at the time. Times have changed since then. Firstly, the legislation governing this industry is undergoing change. Secondly, government is conducting a holistic review of the structure of the corporate tax regime to enhance efficiency and review existing incentives (as announced in the 2020 and 2021 Budget Reviews). Thirdly, there has been renewed exploration interest that has produced promising discoveries.

Government wants to evaluate whether the fiscal regime for the upstream petroleum is suitably designed to create a balance between attracting investment and generating a suitable level of government revenue, while remaining mindful of South Africa's commitments to reducing carbon

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[2] Two IMF reports are available here: https://www.imf.org/en/Publications/CR/Issues/2016/12/31/South-Africa-Technical-Assistance-Report-Fiscal-Regimes-for-Mining-and-Petroleum-43244 and here: https://www.taxcom.org.za/docs/20171113%20IMF%20Oil%20and%20Gas%20Report%20on%20website.pdf

[3] one example can be found here: https://www.bowmanslaw.com/insights/oil-gas/upstream-petroleum-resources-development-bill-potential-impacts-on-upstream-oil-and-gas-companies/

[4] Explanatory Memorandum to the 2006 Revenue Laws Amendment Bill

emissions. This was made public when the following was announced in the 2019 Budget Review: "*South Africa will review its oil and gas tax regimes in 2019".* At the outset, it is important to state that Government values and understands the importance of certainty and transparency for investors. It is within this spirit that this discussion paper is being published. This document aims to lay the foundation for working towards a revised tax regime that is adaptive to changing circumstances and complementary to the UPRD Bill, so that investors have a clear understanding of the fiscal terms. It also seeks to invite investors' views on its content so that – collectively – we can ensure we have a regime where both government and investors gain a fair share.

This document explores the context (in addition to the fiscal regime) that shapes investment decisions in upstream oil and gas – namely geological certainty (the extent of estimated and known reserves, and the viability of extracting them); oil and gas prices; and environmental considerations.

Climate change is a global challenge. The Glasgow Climate Pact agreed at the recent COP26 meeting requires countries to "*transition towards low-emission energy systems, including by rapidly scaling up the deployment of clean power generation and energy efficiency measures, including accelerating efforts towards the phasedown of unabated coal power and phase-out of inefficient fossil fuel subsidies*". It further recognises the need for support for a just transition and targeted support to the poor and most vulnerable based on national circumstances.

South Africa made commitments under the 2015 Paris Climate Agreement to further reduce our greenhouse gas emissions and to contribute to global efforts to limit warming to well below 2°c above pre-industrial levels and to pursue efforts to achieve the 1,5°c temperature goal. Our commitments are set out in the 2nd and 3rd Nationally Determined Contributions (NDCs) submitted to the UNFCCC at the COP26 meeting. This requires a peaking of our greenhouse gas emissions in 2025 in the range of 398 to 510 Megatonnes (Mt) and a sharp decline in emissions from 2026 onwards in the range of 350 to 420Mt. A rapid and significant decline in greenhouse gas emissions from the energy sector, in particular from electricity generation and liquid fuels, will therefore be necessary. Clean energy solutions such as solar photovoltaic and wind are now cost competitive with conventional fossil fuels and, combined with investments in battery storage, would be crucial for the transition to a lower-carbon, climate resilient economy.

The recent COP26 meeting provides important context for Government's decisions on policy for the oil and gas industry. While gas is a fossil fuel, its emissions are less carbon-intensive than coal, and it is an important transition fuel to ensure a secure and affordable supply of energy. Government is seeking to balance the need to invest in less-carbon intensive fuels such as gas with providing a fiscal and tax regime that is attractive enough for companies to explore for and produce oil and gas, but at the same time avoids incentivising assets that could be stranded due to stricter climate commitments and environmental regulations.

The document provides an overview of an array of fiscal regimes and fiscal instruments used worldwide in this industry. The international review shows diversity in countries' approaches – no one regime can simply be copied for use in another country. Each country will have its own unique set of circumstances – geology; location of known reserves (e.g. shallow versus deep water); existing infrastructure or lack thereof; political economy and actual and perceived level of political risk, as well as the government's track record and credibility in enforcing legal commitments.

An overview of South Africa's current fiscal regime for the oil and gas industry is outlined. A discussion ensues – questioning which fiscal regime and fiscal instruments are best for South Africa. This considers the type of fiscal regime, fundamental tax policy design principles, and modelling a variety of fiscal and tax regime options to inform what an optimal tax regime may look like in combination with the State's carried interest as captured in the UPRD Bill tabled in Parliament. It also considers the work done by the Davis Tax Committee and IMF in this regard.

It is important to mention at the outset that data on estimated reserves used for the modelling exercise has been obtained from the Petroleum Agency of South Africa (PASA). The figures included are based on "P50" (probability of 50%) / "best guess" estimates that are yet to be discovered. Importantly, they cannot be regarded as existing with certainty.

Following this is an initial discussion based on all the insights gained from the research and modelling on what could be an appropriate regime for South Africa. Options for revising the current regime are discussed before moving to policy proposals that the public are invited to provide comments on. Government is also interested in receiving comments in respect of all other content in this document – including in respect of how climate change will impact this industry and how the tax system should treat fossil fuel investments.

2. Context – what shapes investment in upstream oil and gas?

There are a number of factors that will influence investment decisions in the South African upstream oil and gas sector in the coming years. These provide important context from which to review the Tenth Schedule with the objective of working towards an optimal tax policy regime. They include geology (the extent of known versus unknown features of oil and gas reserves, and the location and ease of access of the oil and gas); oil and gas prices; environmental considerations; and the political economy.

2.1 Geology – what is oil and gas and how are they extracted?[5]

Fossils have been heated in layers of the earth for millions of years – forming a spectrum of different molecules that yield a spectrum of oil and gas types. Oil exists in many types of quality – ranging from heavy, sulphur-rich Canadian oil sands to ultra-light shale oil. Similarly, gas does not come in only one form. Shale is the source rock for most oil and gas and, over years, the oil and gas migrate towards the surface. There are three fluids occurring in porous, permeable rock – water, oil and gas. Companies and governments are interested in extracting the latter two – the hydrocarbons.

As the oil and gas migrate towards the surface, they become trapped by an impermeable layer of rock, known as a trap or seal. These traps and seals can be filled with oil or gas, or both. Associated gas refers to gas trapped with oil, while non-associated gas is trapped on its own. If a formation under an impermeable layer of rock is large enough, it can trap a large amount of natural gas under the ground in what is known as a reservoir. These types of formations are what the large oil and gas companies have sought for decades. Conventional methods to extract the hydrocarbons involved drilling single or

[5] From various online lectures – available: https://www.youtube.com/watch?v=k4cVxGndh9g; https://www.youtube.com/watch?v=pe71rV92GY8; https://www.youtube.com/watch?v=RsAkj2xFTMc
As well as: http://naturalgas.org/naturalgas/processing-ng/

multiple wells onshore (land) or offshore (sea). The pressure in the trapped reservoirs sends the oil and gas to the surface.

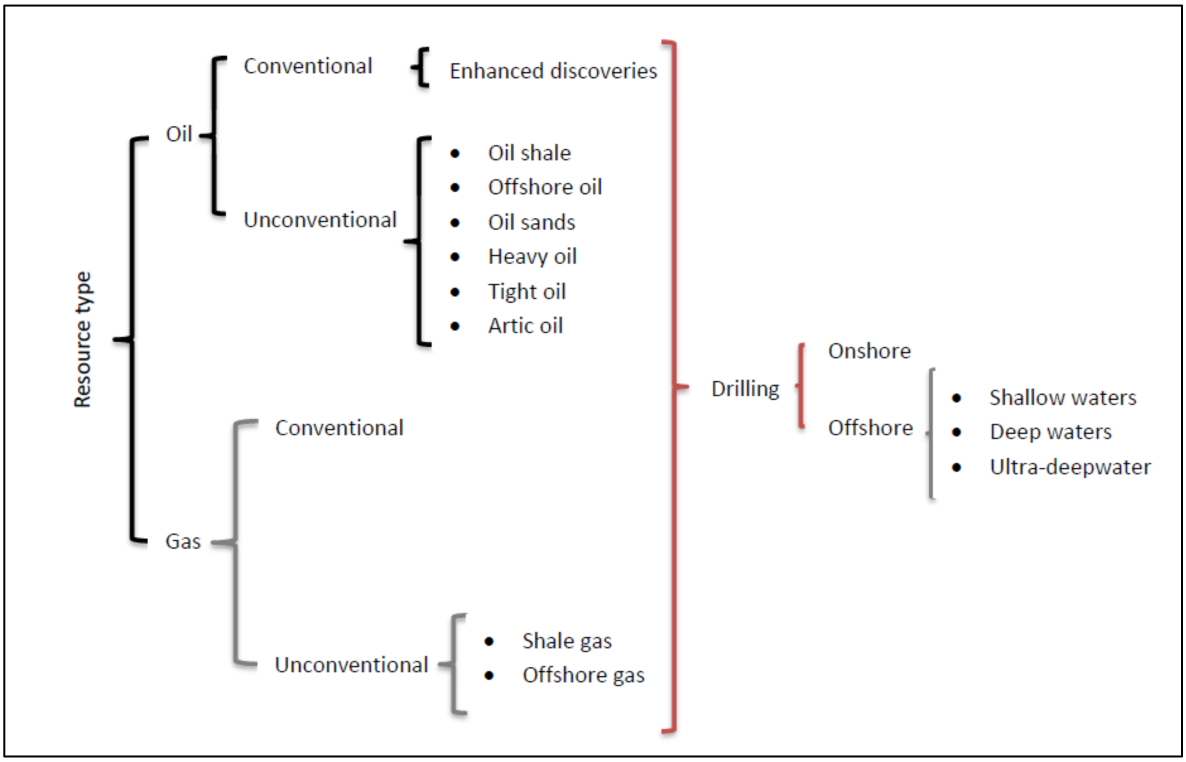
More recently, advances in technology have enabled direct tapping of the source rock. Companies have known that there is oil and gas in shale, but it was not economical to extract previously. The advent of horizontal drilling and hydraulic fracturing ('fracking') has made extraction from shale possible. These are known as unconventional extraction methods. Water is pumped down, which fractures the rock to release the oil or gas.

Oil and gas can thus be extracted using either conventional or unconventional methods in both offshore and onshore locations. Figure 1 provides and overview of the difference resource types and extraction methods.

Conventional oil and gas resources are those in which oil and gas can be economically produced given natural reservoir conditions. These conventional operations typically focus on large subsurface structures underground that are relatively easy to drill and easy to reach. Most of these structures have been drilled over the last 100 years or so, and oil and gas companies now venture to more complex and capital-intensive alternatives, such as deep water offshore and onshore tight/shale oil and gas.

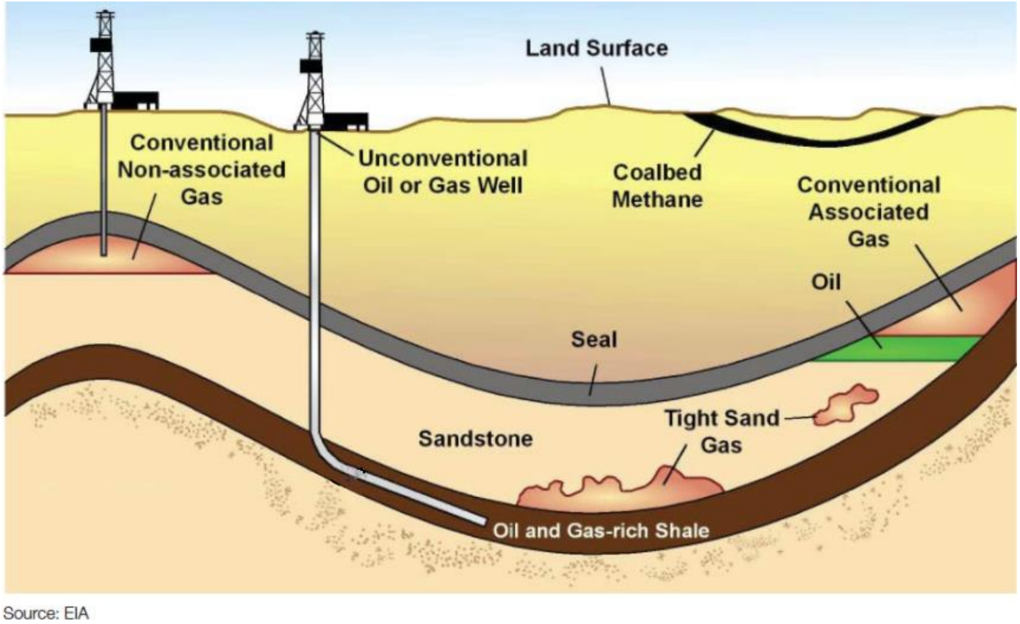
In contrast, unconventional oil and gas resources are resources that are generally deeper and more difficult to recover than traditional oil and gas resources that have historically been produced. Unconventional resources include geologic formations that contain oil and gas, but require advanced recovery techniques due to technical challenges posed by the physical properties of the reservoir. Figure 2 illustrates associated and non-associated gas, as well as some examples of conventional and unconventional extraction methods.

Figure 1: Resource type and extraction methods



Source: adapted from https://www.studentenergy.org/map

Figure 2: Conventional vs unconventional oil and gas



Source: https://www.croftsystems.net/oil-gas-blog/conventional-energy-unconventional-energy-what-does-it-all-mean/

Developing, producing, and upgrading oil and gas from unconventional resources tends to be more capital-intensive than conventional operations. In general, unconventional oil and gas production tends to involve more surface disturbances and wells (due to increases in roads and servicing traffic, as well as tighter well spacing, even when advanced drilling techniques are employed). Additionally, unconventional oil and gas production tends to involve considerably more energy and water use than conventional extraction operations.

Shale and tight resources are unconventional because of the methods used in their extraction, and the types of reservoir from which they are produced. Both shale and tight resources are locked in geological formations that are deeper and more difficult to recover and usually require the combination of two technologies – horizontal drilling and fracking to release the hydrocarbons. In the development of tight gas, typically from impermeable and nonporous formations, significantly more wells are required to produce the same unit of gas that could be produced from conventional formations with less energy use and surface disturbances.

Because the successful extraction of natural gas from unconventional resources requires specialised drilling and completion techniques, such approaches tend to generate greater environmental concerns. For example, unconventional gas extraction tends to produce greater surface disturbances as well as large volumes of produced water (mud water). Although horizontal drilling techniques have emerged to connect more reservoir surface to the wellbore, unconventional gas development on a cumulative basis appears to be expanding the oil and gas industry’s environmental footprint. Nevertheless, technology advances are slowing the rate of environmental degradation and will be integral to future remedies and control strategies.

Oil and gas can be extracted onshore or offshore. Onshore drilling is used for underground reservoirs anywhere on dry land. Drilling on land generally requires relatively low investments and entails fewer risks. Offshore drilling is used to extract oil and gas deposits buried under the ocean floor. Offshore drilling rigs are installed, operated and serviced on large platforms built in the ocean. This allows companies to access deposits under the ocean floor where water depths are greater than 1000 metres (deep water). Most offshore production takes place in what is referred to as the continental shelf or the underwater land mass that surrounds continents. Due to complexities, offshore drilling consumes a large amount of resources before any extraction can take place, thus increasing the risk of financial losses, especially if drilled wells come up dry.

The surface of the ocean can be shallow, deep or ultra-deep. Shallow water refers to water of depths of less than 150 meters, whereas deep water refers to water of depths greater than 150 meters. Shallow water has become relatively less expensive and less technically challenging for operators to explore and drill, but changing economics and the exhaustion of some shallow offshore resources has sparked the push to deep water or, in some areas, ultra-deep water (at depths of 1,500 meters or more) resources. Advancements in drilling technology, dynamic positioning equipment, and floating production and drilling units have made deeper water projects viable, although it requires more investment and time compared to shallow waters or onshore developments.

2.2 Oil and gas prices

During 2020, the oil market experienced a major downturn – fueled by the ongoing price war between Russia and Saudi Arabia, and the collapse in global demand due to the COVID-19 pandemic. Currently, both oil and gas markets have recovered from the significant price fall experienced in mid-2020 as global activity increases and more people get vaccinated.[6] As the world transitions to less carbon emissions, governments are imposing stricter regulatory regimes and introducing carbon pricing mechanisms while shareholders and funding institutions are being more circumspect about what to fund. This is likely to have a dampening effect on oil and gas prices. The history of oil and gas prices is marked by cycles of boom and bust, dominant companies and government intervention.

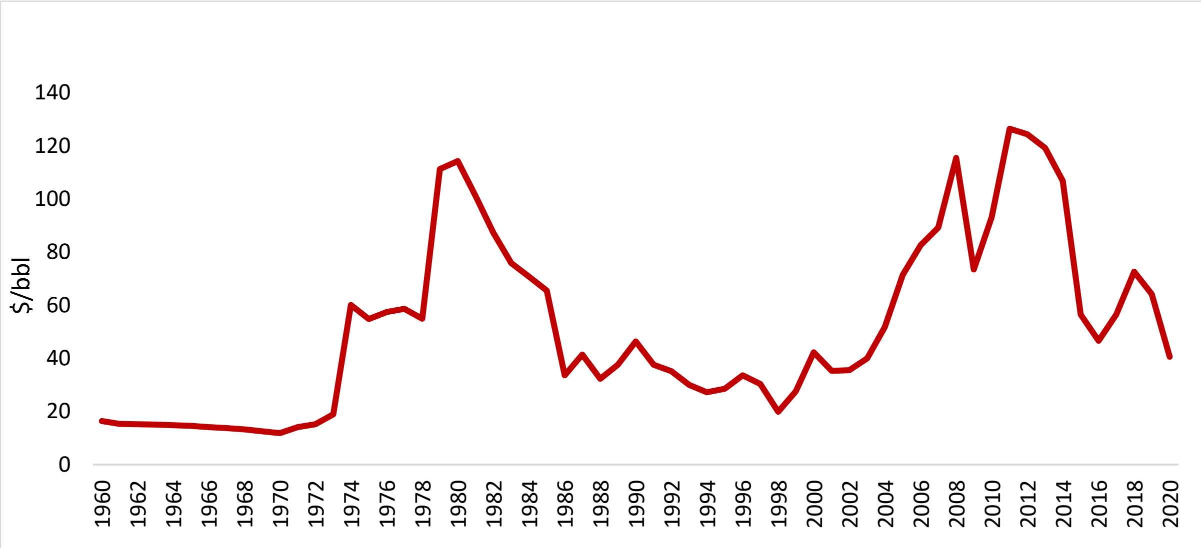
a. Oil pricing

In the early 1950s numerous shifts started occurring – resulting in the transfer of control over oil and gas production and pricing to oil producing countries. Prior to this shift, large oil companies known as the Seven Sisters controlled every barrel of oil (ranging from exploration to its use as finished product), as well as the supply of oil worldwide.[7] These companies set their own oil prices (known as posted prices) and oil producing countries received royalties on a percentage basis. This worked well for oil companies, but not for oil producing countries. Countries such as Venezuela and Iran started to push for higher oil revenues, which led to more oil producing countries asserting control over both their natural resources and oil prices. The result was a move away from concessionary (typically tax and royalty) regimes and the introduction of production sharing agreements (contracts between state and company), which allowed for state participation.

It was during this time that the Organization of Petroleum Exporting Countries (OPEC) was founded to assist member states to secure fair and stable prices for petroleum producers – profoundly altering the structure of the oil industry. In 1973, OPEC imposed an embargo on oil exports resulting in a quadrupling of oil prices (real terms) from 19 US dollars per barrel in 1973 to 60 US dollars per barrel in 1974 (see Figure 3).

[6] https://www.eia.gov/outlooks/steo/
[7] James Speight Introduction to petroleum technology, economics and politics (2011).

Figure 3: Annual crude oil prices, 1960 – 2020



Source: Reserve Bank[8] and BP[9]

OPEC pricing policy also led to the increase from 14 to 35 US dollars per barrel in 1980. The mid-1980s saw a significant shift in OPEC policy, resulting in oil prices declining between 1985 and 1986. The weakening global demand for oil due to economic downturn led to the oil price declining between 1990 and 1991, and in 2001 (US experienced a recession and Asian crisis). The global financial crisis led to a sharp price decline in 2009, whereas the rapid growth in unconventional oil – particularly due to US shale production – led to the 2016 oil price decline. The 'price war' on US shale opened the door for Russia who became the plus member of OPEC. However, the disagreement between Russia and Saudi Arabia continues to create an imbalance in the market. The latest episode (2020-) due to the COVID-19 pandemic could constitute the fourth largest price drop. In short, oil prices are very difficult to predict – any external shock affecting either supply or demand or both can have a significant effect on prices. However, with increases in global activity and vaccinations for Covid-19, oil markets have recovered from the significant price fall experienced in mid-2020.

Spot-related formulae prices are used to price oil and gas. With regard to oil prices three main benchmarks exist, namely West Texas Intermediate (WTI) in the US; Brent in the Atlantic basin (main international benchmark); and Dubai in Asia. These benchmarks have had their fair share of challenges, reflecting the complexity of pricing oil.

b. Gas Pricing

Most wells that are drilled to extract oil have what is known as associated natural gas, which for a long time was considered a no-value by-product of oil production that was usually flared or re-injected into the field to maintain the oil well pressure. Being a gas, it has low calorific value per volume, making it difficult to store and transport – requiring significant investment in infrastructure.[10] Just as in oil markets, gas markets were characterised by monopolistic behaviour with market deregulation taking place in the 1980s, led by the US. Deregulation in the gas market resulted in the creation of trading

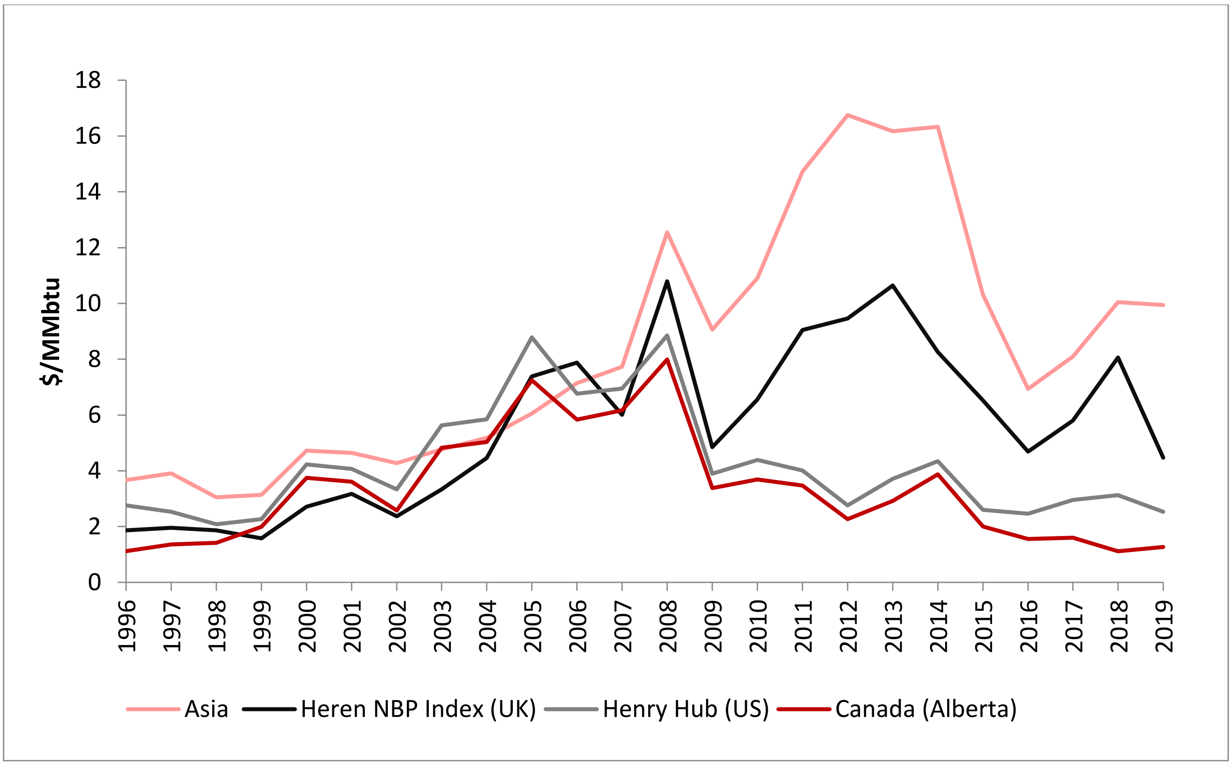
[8] https://www.resbank.co.za/Research/Statistics/Pages/OnlineDownloadFacility.aspx
[9] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html
[10] World Energy Outlook (2019) p188

hubs such as the US Henry Hub in the 1980s, the British National Balancing Point (NBP) and later the Dutch Title Transfer Facility (TTF) – representing the Continental European market in 2010. The opening of the market to competition resulted in a flood of new gas supply, leading to the creation of the NBP in 1996 and NBP futures contracts on the Intercontinental Exchange (ICE) the following year.[11] Figure 4 shows regional hub prices for the period 1996-2019.

Between 1996 and 2008, regional prices were in a narrow band and roughly comparable, until 2010. From 2011 a wide spread in regional prices can be observed with the Henry Hub prices averaging $3/MMbtu[12] while during the same period the Asian LNG prices reached $16/MMbtu, with European prices at $10/MMbtu. The regional spread started to close from 2016 onwards marked by a narrowing of the price bands.

According to the International Energy Agency, over 45 per cent of the world's energy demand was met by natural gas in 2018, with the US and China being the largest consumers.[13] Looking at the African continent, the demand for natural gas has been relatively low with gas only making up 5 per cent of the total energy mix. The recent gas discoveries in Mozambique, Tanzania, Egypt, Senegal and South Africa could have significant influence on the demand for gas.[14]

Figure 4: Regional natural gas prices, 1996 – 2019



Source: BP[15]

[11] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/07/European-traded-gas-hubs-a-decade-of-change-Insight-55.pdf and https://www.oxfordenergy.org/wpcms/wp-content/uploads/Chapter%203.pdf

[12] MMbtu = million British Thermal Units

[13] International Energy Agency, World Energy Outlook (2019) p180

[14] WEO (2019)

[15] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html

2.3 Environmental considerations

Demand for energy is expected to double over the coming decades to meet the needs of a growing and developing global population. The challenge is to meet world energy demand while minimising the negative impact on the environment.[16] The broad environmental issues faced by oil and gas exploration and production are demonstrated in both local and global levels. They include climate change, habitat protection and biodiversity, air pollution, marine and freshwater discharges, incidents and oil spills, and soil and ground water contamination. While the industry is making progress to respond to these issues, ensuring that all operations conform to the current good practice has been a challenge, which is further exacerbated by the climate change challenge.

Climate change is the biggest environmental challenge and risk facing the world and should not be regarded as a major threat or alternative to, but should rather become an integral part of development efforts in the oil and gas sector through embracing the global energy transition and use of low-carbon technology. Even in a decarbonising world, the United Nations Environment Programme (UNEP) recommends that policy makers create awareness of the climate-related risks associated with economic and energy reliance on fossil fuels, as well as the opportunities presented to oil and gas producing countries by the global energy transition.[17] This includes assessing the climate change impacts on oil and gas operations through increased storms, droughts, flooding and sea level rises, which could affect infrastructure – an example being the recent *The Norilsk* diesel oil spill near Norilsk, Krasnoyarsk Krai, Russia which began on 29 May 2020, resulting in ecosystems pollution from diesel spills.[18]

As demonstrated by the Deepwater Horizon disaster in 2010, oil spills have the potential to damage entire ecosystems.[19] British Petroleum's (BP) Deepwater Horizon oil spill released approximately 200 million gallons of oil into the Gulf of Mexico, fouling beaches and coastal wetlands from Louisiana to Florida. It killed birds, fish and marine mammals, and devastated the recreation and fishing-based coastal economies of the Gulf States. Oil spills can take many years to clean up. Nearly 20 years after the Exxon Valdez spill, more than 26,000 gallons of oil still remain in shoreline soils.[20] More recently, in 2020, a cargo ship ran aground on a coral reef nearby Mauritius. The accident resulted in an oil spill of up to one 1,000 tonnes.[21]

To make progress towards environmental sustainability, the core requirements of sustainability which include biophysical system integrity and basic human well-being must be met.[22] Identifying and selecting alternative energy sources that are less destructive is beneficial for the environment. This will

[16] United Nations Environmental Programme (UNEP,2016)https://www.resourcepanel.org/reports/green-energy-choices-benefits-risks-and-trade-offs-low-carbon-technologies-electricity

[17] Climate Change and the Energy Transition: Considerations for oil and gas producing countries. UN Environment Global Workshop for Countries Supported by Norway's Oil for Development Programme, 27-30 August 2019, United Nations Palais, Geneva, Switzerland

[18] https://on.ft.com/38yqx08; https://www.bbc.com/news/world-europe-52977740

[19] https://www.theverge.com/2020/4/20/21220595/deepwater-horizon-bp-oil-spill-gulf-of-mexico-10-year-anniversary

[20] https://www.nationalgeographic.com/science/2020/04/bp-oil-spill-still-dont-know-effects-decade-later/

[21] **https://www.climatechangenews.com/2021/02/19/mauritius-oil-spill-raises-concerns-ship-fuel-safety/**

[22] UNED E&P Forum (1993) "Environmental management in oil and gas exploration and production" https://wedocs.unep.org/bitstream/handle/20.500.11822/8275/-Environmental%20Management%20in%20Oil%20%26%20Gas%20Exploration%20%26%20Production-19972123.pdf?sequence=2%26isAllowed=y

require planning processes that engage early on environmental issues to avoid the use of undesirable alternatives that are environmentally unfriendly.[23]

According to the United Nations Environment Programme Industry and Environment Centre (UNEP IE)[24], the potential for oil and gas operations to cause negative environmental impact must be assessed on a case-by-case basis. This is because different operations in different environments under different circumstances may produce large variation in the magnitude of the potential impact. The potential impact of exploration and production must be considered in the context of national and global protection policies and legislation. The use of renewable energy sources is a key solution to decrease greenhouse emissions arising from the use of polluting fossil fuels.

Investors are becoming more circumspect with investing in carbon-intensive assets as the costs of financing oil and gas exploration is getting higher, and some banks are withdrawing from financing such projects. Many corporates have ESG (environmental, social and governance) objectives on which shareholders hold them to account. These have largely come about due to a mix of public and shareholder pressure. But governments are also starting to review policy frameworks in this regard. According to UNEP, governments are encouraged to apply the principles adopted by the Task Force on Climate-related Financial Disclosures – by undertaking climate-related risk assessments of their economies, identifying a range of scenarios, evaluating national impacts and identifying potential responses. Although work on this front is still nascent even amongst developed oil and gas producing countries, efforts and pressure to get oil and gas and other companies to disclose how they view climate risk should be commended as this process will have a material impact on finance flows.[25]

One of the big challenges facing investment in the upstream oil and gas sector is the risk of stranded assets and high debts. Abrupt climate policy measures and rapidly advancing low-carbon technology could lead to write-downs of carbon-intensive assets used in extraction. For banks having lent the capital required to purchase such assets, this poses a risk to balance sheets. For governments designing optimal fiscal regimes for upstream oil and gas activities, these considerations are important.

Addressing the challenges of climate change through facilitating a viable and fair transition to a low-carbon economy is essential to ensure an environmentally sustainable economic development and growth path for South Africa.

Global commitments to accelerate efforts to transition the energy sector were reaffirmed at the recent 26th Meeting of the Conference of Parties (COP26) under the United Nations Framework Convention on Climate Change (UNFCCC). The Glasgow Climate Pact requires countries to "*transition towards low-emission energy systems, including by rapidly scaling up the deployment of clean power generation and energy efficiency measures, including accelerating efforts towards the phasedown of unabated coal power and phase-out of inefficient fossil fuel subsidies*". It further recognises the need for support for a just transition and targeted support to the poor and most vulnerable based on national circumstances.

As a top 20 emitter of greenhouse gas emissions globally, South Africa made commitments under the 2015 Paris Climate Agreement to further reduce our greenhouse gas emissions and to contribute to

[23] Rand (2008) Environment, Energy, and Economic Development www.rand.org
[24] United Nations Environmental Programme (UNEP,2016): https://www.resourcepanel.org/reports/green-energy-choices-benefits-risks-and-trade-offs-low-carbon-technologies-electricity
[25] Ibid

global efforts to limit warming to well below 2°c above pre-industrial levels and to pursue efforts to achieve the 1,5°c temperature goal. Our commitments are set out in the 2nd and 3rd National Determined Contributions (NDCs) submitted to the UNFCCC at the COP26 meeting. This requires a peaking of our greenhouse gas emissions in 2025 in the range of 398 to 510 Megatonnes (Mt) and a sharp decline in emissions from 2026 onwards in the range of 350 to 420Mt. A rapid and significant decline in greenhouse gas emissions from the energy sector, in particular from electricity generation and liquid fuels, will therefore be necessary.

The carbon tax is South Africa's key mitigation policy measure and, combined with other climate policies, it is integral to achieving our NDC commitments in an economically efficient manner. The first phase extends from 1 June 2019 to 31 December 2022, and the second phase from 2023 to 2030. The Carbon Tax Act gives effect to the polluter-pays-principle for large emitters and helps to ensure that firms and consumers take the negative adverse costs (externalities) into account in their future production, consumption and investment decisions. For example, the carbon tax encourages internalisation of the costs associated with excessive GHG emissions by adjusting relative prices to reflect the social costs of carbon-intensive goods and services. The carbon tax will assist in reducing GHG emissions in a cost-effective manner, help to achieve our NDC target and nudge our economy onto a sustainable growth path.

The carbon tax has been introduced in a phased manner at a relatively low rate initially to allow businesses time to make the necessary structural adjustments to their production processes and practices and to ensure a just transition to a low-carbon, climate resilient economy. Firms are incentivised towards adopting cleaner technologies over the next decade and beyond[26] to help meet the NDC target.

The carbon tax applies initially only to direct (scope 1) emitters and the design also provides significant tax-free emission allowances ranging from 60 per cent to 95 per cent in the first phase. This results in a relatively low tax rate to enable significant emitters to transition their operations to cleaner technologies through investments in energy efficiency, renewables and other low carbon measures.[27]

Upstream oil and gas operations (mainly exploration and production) contribute to a range of GHG emissions, including CO_2, methane (CH_4), and fluorinated gases. Under the Carbon Tax Act, the Intergovernmental Panel on Climate Change (IPCC) classification for emissions reporting is applicable. As a result, oil and gas activities must report emissions under energy – fugitive emissions from fuels category, IPCC Code 1B (fugitive emissions from fuels), specifically 1B2 for oil and natural gas production. Under the 1B2 category, all activities have a threshold of "none" which means anyone conducting those activities needs to report their emissions, irrespective of size of operation.

For the first phase of the carbon tax until December 2022, the tax-free allowances applicable to oil and gas activities include:

- A basic tax-free allowance of 60 per cent;
- A variable tax-free allowance for trade exposure (to protect international competitiveness) up to a

[26] Ibid

[27] Media Statement on publication of the Carbon Tax Act available on http://www.treasury.gov.za/comm_media/press/2019/2019052701%20Media%20statement%20-%20Carbon%20Tax%20Act.pdf

maximum of 10 per cent;

- A maximum tax-free allowance of up to 5 per cent for performing better than the benchmark emissions intensity of the industry;
- A 10 per cent tax-free allowance for fugitive emissions;
- A 5 per cent tax-free allowance for for participating in the initial voluntary phase of the Department of Environment Forest and Fisheries -led carbon budgeting process; and
- A carbon offset allowance of up to 5 per cent.

The total tax-free allowance during the first phase will be capped at 95 per cent for the oil and gas sector. With a current headline tax rate of R134 per ton CO_2e and various tax-free allowances, the effective carbon tax rate ranges from about R6 to R50 per ton of CO_2e. The significant tax-free allowances combined with recycling of revenues (through a deduction of the electricity generation levy and energy efficiency savings tax incentive) provides short term transitional support to cushion vulnerable households and energy intensive industries.[28]

As stated in the Medium Term Budget Policy Statement, announcements on the second phase of the carbon tax, which begins in January 2023, will be made in the 2022 Budget. The design of the carbon tax will consider the imminent implementation of carbon border adjustments by the European Union, which could adversely impact exports of carbon intensive goods, and contribute towards achieving the recent Cabinet-approved NDC commitments and 2050 net zero emissions goal set out in the Low Emissions Development Strategy.

This discussion document does not fully consider stronger measures that may be required to deal with climate change – including whether and to what extent oil and gas will be a transitional fuel and source of energy, and for how long. South Africa is in the process of determining further measures to achieve its NDCs, including to what extent gas could act as a transitional fuel and energy source in relation to coal. These are issues that will need to be considered in respect of the tax regime for fossil fuels, and to ensure consistency with the future development of the carbon tax as it is revised for its next phase.

Government recognises that, while gas is a fossil fuel, its emissions are around 50 per cent less than coal and it could act as an important transition fuel as the economy transforms and shifts to lower-carbon, renewable and energy efficient technologies. This would also help to facilitate a just transition to a lower-carbon economy and ensure energy security of supply and affordable energy that is accessible by all.

As a complementary measure to the Carbon Tax, the National Treasury published a draft paper "*Financing a Sustainable Economy*" on 15 May 2020.[29] It provides an overview of climate change in South Africa and commitments made by the Government. It recommends interventions to ensure more sustainability in financial activities (whether in banking, insurance, retirement funds, collective investment schemes, private equity or capital markets).

The National Environmental Management Act (NEMA) is an important piece of legislation pertaining to this industry and is discussed in Annexure A.

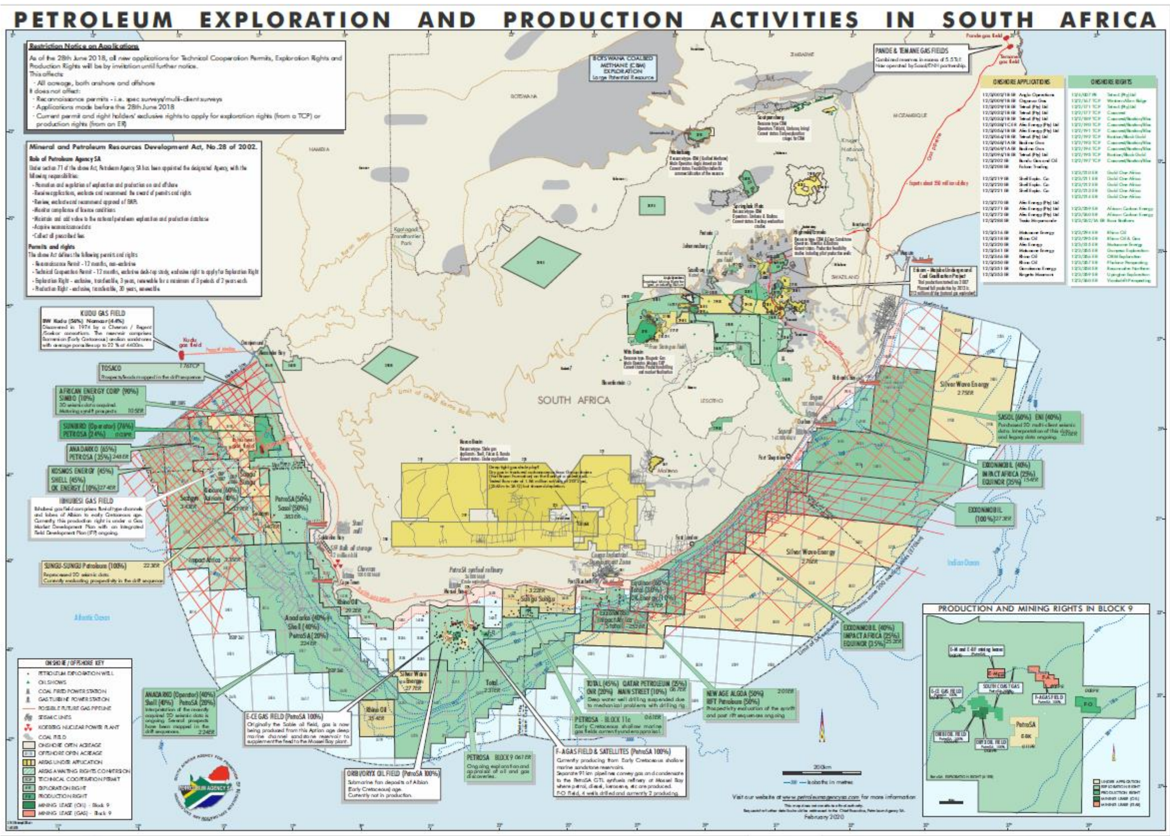
[28] Ibid

[29] http://www.treasury.gov.za/publications/other/Sustainability%20technical%20paper%202020.pdf

3. Overview of South Africa’s oil and gas sector

The history of oil and gas exploration drilling in South Africa dates back to the 1960s. However, significant exploration activities only began during the 1980s and 1990s. There are four major basins in South Africa, one onshore and three offshore. There is the onshore Great Karoo Basin; the Orange Basin off the west coast; the Outeniqua Basin off the south coast and the east coast Durban and Zululand Basins (Figure 5[30]). South Africa’s offshore basins have shown the presence of both gas and oil during earlier exploration activities. In 1992 domestic natural gas production started offshore in Mossel Bay whilst crude oil production only began in 1996 from the Bredasdorp sub-basin of the Outeniqua Basin off the south coast. To date most of the country’s oil and gas production comes from the Bredasdorp sub-basin of the Outeniqua Basin in Block-9, which is operated by the Petroleum Oil and Gas Corporation of South Africa (PetroSA).[31]

Figure 5: South Africa’s key energy sites[32]



<u>Source</u>: *Petroleum Agency South Africa (PASA)*

According to a study that was done by Wood Mackenzie[33], 22 exploratory and appraisal wells were drilled between 1986 and 1990. By 2014, only 36 hydrocarbon discoveries had been made, of which 15 were producing, one was at pre-production stage, three had ceased production and 17 were considered too small to develop. A resource-estimation exercise was carried out by Wood Mackenzie and Table 1

[30] Please use this link to view a better quality and ‘zoomable’ map: https://www.petroleumagencysa.com/index.php/maps
[31] http://www.petrosa.co.za/discover_petroSA/Pages/Historic-Milestones-PetroSA.aspx
[32] http://www.petroleumagencysa.com/index.php/maps
[33] Wood Mackenzie “South Africa’s Oil & Gas Licensing and Fiscal System,” October 2014

shows that, as of 2014, oil and gas reserves at producing plants were depleting.

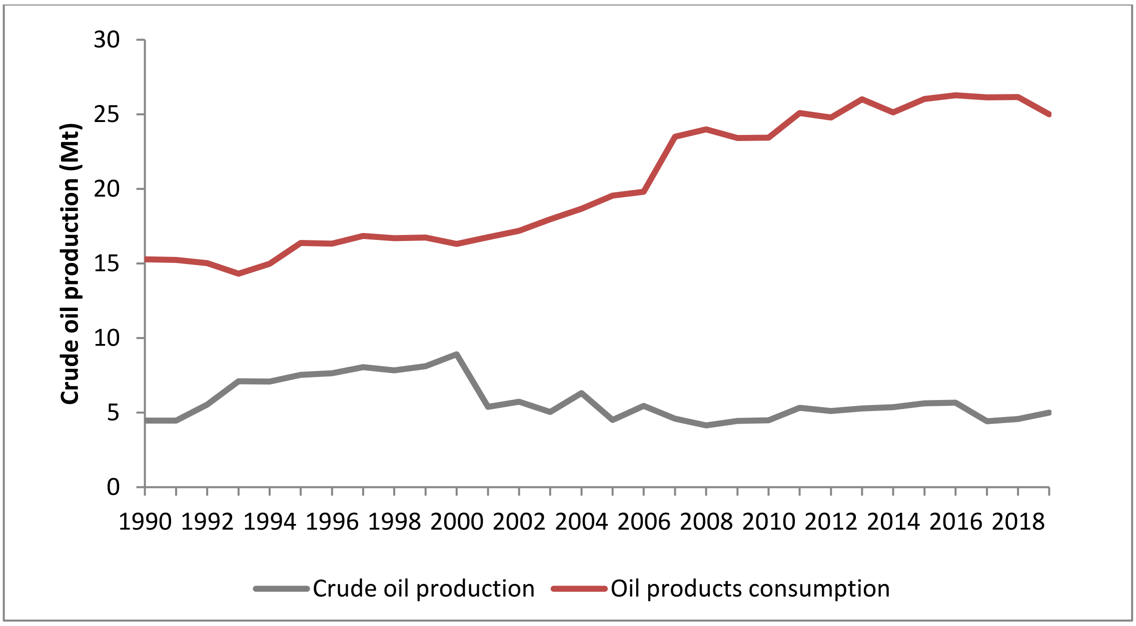
Table 1: Level of gas and oil reserves at producing plants

Location		Initial Reserves		Remaining Reserves (2014)	
		Oil	Gas	Oil	Gas
		MMBbl	Bcf	MMbbl	Bcf
Block 2A	Ibhubesi	4	540	4	540
Block 9	E-M and F-A	52	1487	2	283
	Oribi and Oryx	47	0	0	0
	Sable	24	0	0	0
	South Coast Gas Dev.	5	174	1	56
Total		132	2201	7	879

Source: Wood Mackenzie "South Africa's Oil & Gas Licensing and Fiscal System," October 2014

According to the 2012 BP Statistical Energy Survey, in 2011 South Africa consumed an average of 547.25 thousand barrels of oil a day which is approximately 0.64 per cent of the world total. Almost all the country's domestic fuel demands are met by imported crude oil and the remainder is met by coal-to-liquids synthetic fuels and gas-to-liquid synthetic fuel produced by PetroSA from gas extracted from the Bredasdorp Basin.[34] Figure 6 shows domestic production of crude oil has been declining over time – translating into increasing dependence on imported oil to meet domestic consumption.

Figure 6: South Africa's oil production and consumption



Source: https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html

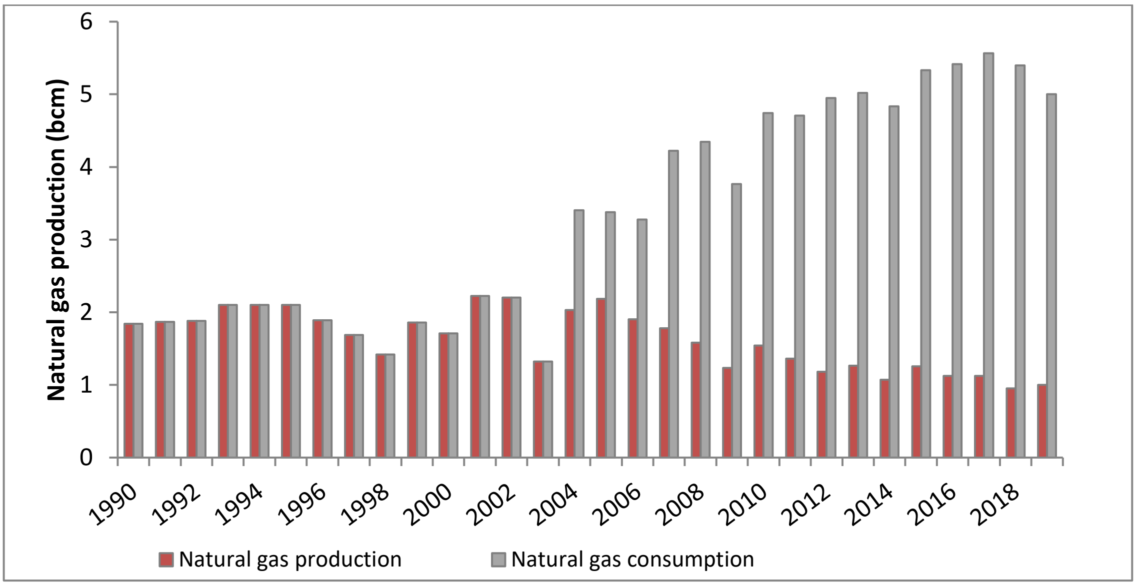
South Africa's exploration in the past has been focused on shallow water blocks. Deep water exploration regained interest and was encouraged in South Africa by the sizable discoveries in deep water

[34] http://www.energy.gov.za/files/media/explained/2019-South-African-Energy-Sector-Report.pdf

exploration in Mozambique and Tanzania during 2010/11. During 2012 several offshore exploration permits were awarded to international oil companies such as Total, ExxonMobil and Anadarko, while a number of companies, including Shell, applied to explore the Karoo basin to extract shale gas. Total's first attempt at drilling the Brulpadda basin in 2014 was suspended due to challenging sea conditions.[35]During July of the same year government launched "Operation Phakisa" intended to create an enabling environment for exploration.[36]

Figure 7 shows the relatively small amount of natural gas that is produced by PetroSA offshore (Bredasdorp Basin), which is not enough to meet domestic demand. Hence the balance of the country's natural gas demand is met through imported natural gas via a transmission pipeline from Sasol's Pande and Temane gas fields in Mozambique. [37]

Figure 7: Natural gas production and consumption



<u>Source</u>: *https://yearbook.enerdata.net/*

South Africa has large reserves of unconventional shale gas in the Karoo. According to the International Energy Agency, technically recoverable gas reserves are estimated at 389 trillion cubic feet (tcf) (as shown in Table 2) – placing the country among the top 10 countries with the highest reserves in the world.[38] Although shale gas was discovered in the Karoo several decades ago, extensive exploration activities are yet to begin as several companies who have applied for exploration licenses are waiting for approval. Environmental concerns over hydraulic fracturing (fracking) have significantly delayed exploration activities. One of the concerns is water availability as the Karoo is a dry region and fracking requires significant amounts of water.

[35] https://www.rystadenergy.com/clients/cube-dashboards/workflow/?did=49
[36] https://www.operationphakisa.gov.za/operations/oel/oilGas/Pages/default.aspx
[37] Joint venture between Sasol, the South African Gas Development Company (Pty) Ltd and Companhia Mocambicana de Gasoduto SARL.
[38] These estimates exclude conventional gas reserves in Mossel Bay and Orange Basin.

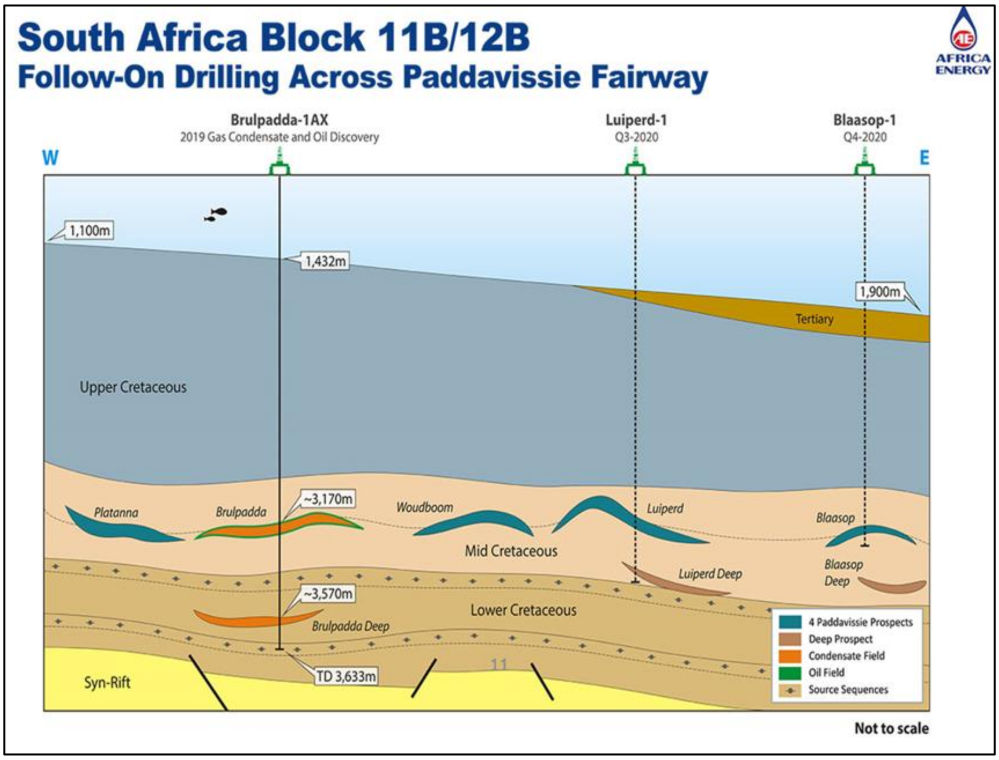
Table 2: Unconventional Gas Reserve Estimates by Resource Type

Basin	Formation	Risked Gas In-Place39 (Tcf)	Technically Recoverable (Tcf)
Karoo Basin	Prince Albert	385	96
	Whitehill	845	211
	Collingham	328	82

Source: *https://www.eia.gov/analysis/studies/worldshalegas/pdf/South_Africa_2013.pdf* (p XIX 2)

Total operates three deep offshore exploration licenses in South Africa. Following the drilling of the first Brulpadda-1AX exploration well on Block 11B/12B in the Outeniqua Basin (south of Mossel Bay) in January 2019, Total announced (on 7 February 2019) a discovery of gas and condensates, and proceeded with a 3D seismic acquisition. According to Rystad Energy[40], the block spreads over an area of 19,000 square kilometres, with water depths ranging from 200 to 1,800 meters, and the discovery is estimated to be between 500 million and 600 million barrels of oil equivalent (boe). Additional 2D and 3D seismic acquisitions started in December 2019 and further drillings commenced during 2020.[41] This led to a further announcement by Total (on 28 October 2020) of a second gas condensate discovery on the Luiperd Prospect after drilling an exploratory well to total depth of 3,400 m.[42]

Figure 8: Total's exploration activity in Block 11B/12B



Source: *https://www.africaenergycorp.com/operations/south-africa-block-11b-12b/*

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39 https://cer.org.za/wp-content/uploads/2012/06/Econometrix-KSG-Report-February-2012.pdf, http://www.dmr.gov.za/mineral-policy-promotion/shale-gas and https://www.eia.gov/analysis/studies/worldshalegas/pdf/South_Africa_2013.pdf p XIX 2

40 https://www.rystadenergy.com/clients/cube-dashboards/workflow/?did=49

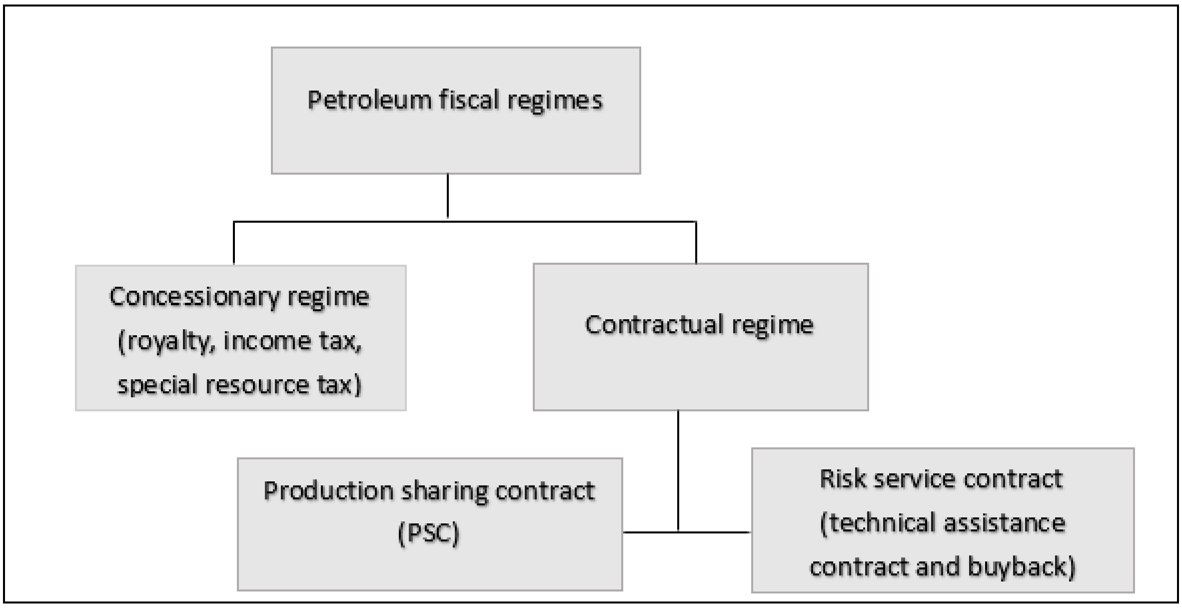
41 Petroleum Agency of South Africa's (PASA) 2019 Annual Report. Available: https://www.petroleumagencysa.com/images/pdfs/AnnualReports/Pasa_2019_Signed_AFS_with_Audit_report.pdf See also page 43 of Total's 2019 Annual Report

42 https://www.businesslive.co.za/bd/companies/energy/2020-10-28-totals-new-gas-find-may-lure-investment/

4. Fiscal regimes for oil and gas

The combined system of tax and non-tax instruments used to raise government revenue from natural resources extractive activity is known as a fiscal regime. Oil and gas fiscal regimes are different from those that apply to other businesses due to the presence of resource rents obtained when valuable natural resources are extracted and because the resources are exhaustible. Fiscal regimes for oil and gas do not only include fiscal instruments such as a royalty and income tax on profits, but also include contractual schemes such as production-sharing or risk service contracts, state participation and obligations to support acquisition of equity interests by designated citizens.[43] Concessions and contractually based systems (which include production sharing contracts (PSC) and service contracts (SC) are the most commonly used types of fiscal regimes. The different regimes shown in Figure 9 tend to differ in the level of risk and ownership that is granted to the investor, with the concessionary systems generally transferring most of the risk and ownership away from the government and service contracts transferring none.[44]

Figure 9: Fiscal regimes for oil and gas



Source: *Daniel et. al. (2010)*

4.1 Concessions

A concession is an agreement where government grants a company the exclusive right to explore for, develop and/or produce resources at its own risk and expense, generally for a specific amount of time. Oil and gas extracted pursuant to these arrangements belong to the investors who, in exchange for such rights, generally pay a royalty on the volumes extracted, as well as other payments such as bonuses and surface rentals.[45] Concessionary regimes usually operate within the existing tax laws. For instance,

[43] www.resourcegovernance.org
[44] Peter D. Cameron and Michael C. Stanley (2015) Oil, Gas, and Mining: A sourcebook for understanding the extractive industries
[45] A surface rental is a rent payable to the government every year for the surface area allotted to an oil and gas permit holder or a lease under these rules at rates not exceeding the land tax assessable on the land by the government.

the standard corporate income tax rate that applies to all industries also applies to the petroleum industry. Added to the existing income tax are various forms of resource rent taxes and/or royalties to compensate government as the resource owner for the resources that will be depleted during the production operations. For this reason, concessionary regimes are also known as “tax-royalty” regimes.

Countries allocate petroleum exploration and production rights in different ways – ranging from a variety of forms of licensing rounds and public tenders to direct negotiation. The majority use a combination of these. While some countries have rigid systems where a few parameters that affect the sharing of rent are biddable, some award rights in respect of work programmes, and for others, everything is biddable. Some examples of biddable parameters include cash bonuses, royalties, and profit shares.[46]

The advantage of a concessionary regime is that they are more straightforward and transparent than other types of agreements, especially if a public bidding system[47] is used to set basic terms (in contrast to discreet direct negotiation between investor and government). Additionally, the financial risk of the project, including the cost of exploration, is absorbed by the contractor. The main disadvantage (for governments) is that a bidder’s perspective is commercial. As a result, the presence of information asymmetry where decisions are made with lack of sufficient information about the potential reserves in the area explored can result in government collecting less revenues. This can result in government accepting lower returns on the project especially if there is lack of adequate knowledge about the potential of a concession area because ground-breaking or profound exploration has not been fully undertaken.

4.2 Contractual regimes

a. Production Sharing contracts (PSC)

A PSC is an agreement between a government and investor. PSCs allow more government control over the exploration, development and production of the resources compared to that in a concessionary system. The terms of the contract are usually separated into distinct and sequential exploration, development and production periods.[48] As with concession arrangements, ownership of the investors’ share of production generally vests with the investors upon production. While the private investor takes on the full risk of the investment, the government retains full ownership of the resource. Once production starts, the oil (or its proceeds) is shared between the state and the investor according to contractual clauses. "Cost oil" is the first component, which allows the investor to recover costs; the second component is "profit oil" – remuneration for risk and capital. The remaining oil (or its proceeds) belongs to the government.[49]

Although the sharing of production is the primary fiscal mechanism for value sharing in these types of contracts, other common forms of fiscal instruments used in PSCs include royalties, profit taxes and bonuses. In some countries, the financial clauses of the PSC supplant all other taxes, while in others taxes still apply within the PSC framework. Important to note is that all tax provisions not specifically

[46] Tordo et al. (2010)
[47] A concession awarding process must be competitive to ensure efficiency. The public bidding system is a way of introducing competition into the industry so that the contracts are given to the most efficient company in the market.
[48] Agalliu, I. 2011. Comparative assessment of the federal oil and gas fiscal systems. U.S. Department of the Interior, Bureau of Ocean Energy Management Herndon. VA. OCS Study, BOEM 2011-xxx. 300 pp.
[49] Bosquet (2002)

included in the PSA are waived. With a PSC, it is difficult to enforce social and environmental standards beyond the contract terms.

Investors are weary of spending large sums of money on long-term, high-risk projects without guarantees about the future tax regime. PSCs are designed to provide this guarantee. To the investor, a PSC offers two advantages: (i) allowing for cost recovery before the payment of taxes (although, in some PSCs, cost oil is limited so the state can collect its share of profit oil or taxes earlier than under a concessionary system), and (ii) locking in taxes for the duration of the project upon contract signature. To the state, a PSC usually ensures a high volume of private investments without financial and operational risk. Government does not risk losses other than the cost of the negotiations (mainly fees paid to advisers).

A study by Ing (2014)[50] suggested that in the absence of information asymmetry or in the case of a small firm a PSC generates higher tax revenue than a concession contract. The study notes that under a PSC, the government has the potential to obtain maximum revenue due to its close association with the production partner. However, this is only possible when the government maintains monitoring of the firm's true costs of production. If the government does not closely monitor or assess the firm's costs, the government may lose potential revenue since the cost recovery mechanism increases the firm's incentive to overvalue its costs. Government can get profits in an efficient manner – keeping part of the production known as profit oil. However, before the government can take its share, the investor has the right to take a share of the oil produced to recover the cost of its investment in the project (cost oil). For government to get a fair share, it requires accurate information of the oil and gas reserves in the field and this requires a high degree of supervision on costs of exploration, development and operation.

b. Service Contracts (SC)

Service contracts are sometimes referred to as Technical Assistance Contracts or Technical Service Agreements because they are generally contracted regarding existing fields. Service contracts tend to be typical for countries where the country only seeks to attract additional expertise. The contractor tends to hold less risk in these situations and provides its services for a fee. In some cases, the contractor may be exposed to cost overruns as compared to approved budgets, and thus sometime these arrangements are referred to as "risk service contracts."

c. Joint Venture or Consortium

This is an arrangement between several investors who may pool capital and expertise to jointly exploit and share the risks connected with exploiting a particular extractive project. The benefit of a joint venture (JV) for a government is that it is not alone in the decision-making and responsibility for a project. It can count on the expertise of a major oil company. All parties share the profits, as well as liabilities for taxes and royalties. Sharing also has a downside for government. Risks and costs must be shared too, making the host government a direct and responsible participant in the natural resource extraction. Responsibility also brings with it potential liability, including for environmental damage.

Table 3 is a summary of the advantages and disadvantages of concessionary regimes relative to PSCs.

[50] Ing, J. (2014): Production sharing agreements versus concession contracts

Table 3: Advantages and Disadvantages of oil and gas fiscal regimes

Oil and gas fiscal regime	Advantages	Disadvantages
Concessionary regimes	• Concessionary regimes are more straightforward and transparent • Technological innovation is high, which results in potential for efficiency gains in all phases of the project development and implementation • Low risk for the government as the investor takes on all the financial risk of the project, including the cost of exploration. In case wells come up dry, the financial burden is largely shouldered by the private company	• Due to information asymmetry, the government may not know the full potential of the area explored through the extensive exploration • May require close regulatory oversight • May have underlying fiscal costs to the government
Production Sharing Contracts	• Low risk for government in that government does not risk losses other than the cost of the negotiations (mainly fees paid to advisers) • It provides certainty for the investor by locking in taxes for the duration of the project upon contract signature • PSCs are beneficial to government in that they ensure a high volume of private investments without financial and operational risk	• Agreements are very complex in structure and require high level of negotiation • Contractual provisions are binding throughout the contract period and may not make provisions for flexibility to adjust to unplanned situations

5. Fiscal instruments

The central objective of fiscal instruments is to ensure that the government – which has legal rights and ownership of the resources – gets a fair share of the wealth accruing from the extraction of resources, while simultaneously encouraging investors to ensure optimal economic recovery of the resource. Instruments include royalties, taxes, production sharing, and bonuses.[51] The fiscal tool or a combination of tools a government chooses to employ for its oil or mining sectors depends on balancing a number of factors, including when government hopes to receive revenues, how to share the investment risk, how to respond to changes in profitability, and how strongly to promote new investments.[52] Table 4

[51] Natural Resource Charter, precept 4 http://www.resourcegovernance.org/sites/default/files/NRCJ1193_natural_resource_charter_19.6.14.pdf

[52] www.resourcegovernance.org

provides a brief overview of fiscal tools used in the oil and gas industry.

Table 4: Fiscal instruments applied to oil and gas

Fiscal tool	Explanation
Royalties	A royalty is a specified (by law or contract) portion of gross sales revenue or of the actual volume of oil and gas produced, which the permit holder hands over to the government. Since royalties are based on or linked to gross revenues, they guarantee upfront revenue for government soon after production begins. There are two major types of royalties – ad-valorem and unit-based. The ad valorem royalty is charged as a percentage of value (generally higher value / volatile price minerals) and the unit-base is charged per unit of weight or volume (generally low value / stable price minerals). Royalties are often criticized as being a regressive form of taxation, since they are paid by investors as production starts. However, this can be remedied by imposing royalty rates that are linked to certain parameters and increase or decrease in response to variations in these parameters (especially when the parameters closely reflect project profitability as is the case with the current mineral royalty regime). The downside of using sales or profit as a tax base is that it is subject to base erosion and profit shifting. Because South Africa is a high tax country – if a company can artificially reduce its sales price (which naturally reduces taxable profits reported in South Africa), it can also reduce its royalty liability.
Production bonus	A production bonus is an amount payable at a specified point in the project timeline. The bonus could be in the form of one or more sums paid to the state triggered when certain production thresholds are reached in the field. Some production bonuses are paid at signature, while others are designed to bring revenues when certain production levels are met. For example, a production bonus may be payable at the start of production or when a certain level of accumulated production is achieved. There will be a specified time period such as a month or quarter during which the average production rate must exceed the benchmark level that triggers the bonus payment. These production bonuses vary in magnitude and depend on the oil potential of the country in question.
Carried interest	Carried interest allows a government to acquire its equity share in the project from the production proceeds instead of making an upfront cash investment. This type of equity can be thought of as similar to a loan extended by the investor to pay the state's equity purchase cost and ongoing participation costs. The investor finances the exploration, appraisal, and possibly even development stage and bears the risk. In the event of no discovery being made, the loss will be borne exclusively by the investor, but should a commercial discovery be made, the government can acquire an equity interest. Under this licensing system, the government's potential interest is, therefore, 'carried' during the various stages by the licensee. Government pays for the participating interest but the investor lends or fronts the money. Government forgoes any dividends or returns until the loan plus interest are paid in full. Free carried interest differs in that interest does not accrue on the amount payable to the investor by the state - it is effectively a form of interest-free loan.
Petroleum Resource Rent Tax	A petroleum resource rent tax (PRRT) is a profits-based resource tax used to tax oil and gas projects. The aim is to tax excessive returns after considering all available deductions. A percentage of the profits are extracted from a project in recognition that the investor has been given the right to extract an exhaustible natural resource. Unlike a royalty regime, a PRRT applies to the profits derived from a petroleum project and not the volume or value of the petroleum produced. By design, the revenue generated will not be stable. An example illustrating this was captured in the Australian Review of the Petroleum Resource Rent Tax (PRRT) when asking what an equitable return is to the communities: *"The community groups consulted were of the view that the PRRT was not providing the Australian people with an equitable return on the development of petroleum resources. In particular, concern was expressed that PRRT revenue is declining at a time when a number of large LNG projects have or will soon come into production that will result in Australia becoming a leading exporter of LNG. Concerns were also expressed that some large LNG projects may not pay PRRT for decades to come, or may never pay PRRT at all."* *"Industry argued that given the surge in investment in petroleum projects, it is inevitable that it will be some time before these projects become cash positive and pay PRRT, especially as some of these major projects have only recently commenced production or are still being developed."*

Corporate income taxes	Taxes are assessed as a percentage of the net profits of a project after deducting allowable expenses. These vary most often based on what deductions are allowed and how they are calculated and monitored.
Withholding taxes	Withholding tax represents tax on payments that extraction companies make to their lenders (interest), owners (dividends) and subcontractors (service fees). A common practice is for companies to be required to withhold a share of payments to these third parties and transfer it to the government. This makes it possible for the government to tax third parties who may not be based in the country but are profiting from the project.
State equity participation	A state may purchase or negotiate shares in an oil or mineral project. Equity gives the state either a share in the distributed profits of a company or the right to distribute some portion of the petroleum or mineral output. It may also entail additional obligations by the state and could increase the government's share of the risk
Surface rental payments	Payments to the central, or sometimes subnational, government based on a fixed or per acre fee

Source: Daniel et. al. (2010); and the Natural Resource Governance Institute

In designing a fiscal regime, government can choose from various fiscal instruments to build a fiscal package that will be suitable for its country's needs. It is important to note that the wide diversity in country objectives, policies, resource potential, and relative development of the extractives industry means that a fiscal package suitable for one country may not be transferable to another.

6. International overview

The oil and gas sector has significant influence on the economies of both oil producing and oil importing countries. Oil and gas companies operate on a global scale, giving them the advantage of comparing fiscal terms among country projects when deciding where to invest.[53] Governments need to ensure that they have competitive fiscal regimes to be considered an attractive investment destination. At the same time, governments need to be mindful about not being more generous than the terms offered in comparable countries. This will include countries with similar geological potential, cost and operating environments, track records, institutional capacity, and perceived and actual political risk. These elements are important for investors when determining where to invest.

An international overview of oil and gas fiscal regimes for 86 countries reveals the regional trends outlined in Table 5. The selected countries either use production sharing contracts, concessions, service contracts or a combination of these (hybrids) to package their fiscal regime.

Table 5: Most prominent types of fiscal regime by region

Region	Type of fiscal regime
Africa	Combination of concessions and production sharing contracts
Asia	Combination of concessions and production sharing contracts
Europe	Mostly concessions
Latin America	Combination of concessions and production sharing contracts
Middle East	Mostly production sharing contracts and service agreements
OECD	Mostly concessions

Source: EY (2019)

According to estimates published by the United States Department of energy, there are 15 countries that account for more than 75 per cent of the world's oil production and hold roughly 93 per cent of its reserves. Of the 15 countries, seven operate concessionary regimes (Canada, Kuwait, Norway, Saudi

[53] Tordo (2007)

Arabia, the United Arab Emirates, the United States and Venezuela). Concessions are mainly used in developed countries, whereas production sharing contracts are more prevalent in developing countries and Africa. For example, countries like Algeria, Equatorial Guinea, Ethiopia, Ghana, Madagascar, Mauritius, South Sudan, Tanzania and Uganda use PSCs. A combination of concessions and PSCs is used in Cameroon, Egypt, Guyana, Kenya, Libya, Mozambique (see Box 1 below for more details), Nigeria, Senegal and Tunisia.

Many of the countries levy a royalty in respect of oil and gas, which is stated as a percentage of gross production value and usually less than 20 per cent. Some countries levy a fixed rate while others have differentiated royalty rates to create progressivity. For example, countries like the United States, Colombia, Netherlands, Australia and Gabon offer progressive royalty rates. Annexure C includes a table with a list of countries and their progressive royalty rates. Some countries differentiate between oil and gas whereby the royalty rate for gas is lower than the rate for oil, as gas development tends to be less profitable. For instance, Ghana, India and Mozambique have different royalty rates for oil and gas. Ghana levies a 12.5 per cent royalty on the gross production of crude oil and a 7.5 per cent royalty on the annual gross production of natural gas. India has a royalty rate payable of 12.5 per cent for crude oil and 10 per cent for natural gas, while Mozambique's rates are 10 per cent for oil and 6 per cent for natural gas. These rates are reduced by 50 per cent when the production of oil and gas is destined for use by local industry, reducing the rate to 5 per cent for crude oil and 3 per cent for natural gas.

Some countries differentiate based on location – for instance a lower royalty rate is imposed for offshore projects or other geographical circumstances which make development costly. Nigeria is an example of a country where the royalty regime is imposed at different rates based on location. The rates range from 20 per cent for onshore production to 0 per cent for offshore areas in excess of 1000 meters.

Australia has oil and gas royalty rates ranging from 10 to 12.5 per cent. In the Australian Petroleum Resource Rent Tax (PRRT) review[54] in 2017, investors complained that the system was not necessarily appropriate anymore as it was previously designed for crude oil, whereas the sector has transitioned into producing mostly LNG. Investors stated that the costs of exploring for and extracting gas are higher relative to oil where cash flow can turn positive earlier on. They argued that the increased costs from this, as well as deep offshore operations, mean that rates could be on the high side. In contrast to this, Australian communities do not feel that the royalties generated are sufficient.

To ensure that government receives some revenue before all of the costs have been recovered, it is common for countries that use PSCs to cap the share of production that is available for cost recovery (cost-oil that covers the costs of project development). The share of each party's profit oil (oil that is in excess of cost oil) may be as simple as the allotment of a fixed percentage for each party in all years, but in many cases the contracts have been constructed to add an element of progressivity to the production sharing terms. This progressivity is usually implemented in the form of an increasing share of the profit oil for the government when certain triggers (e.g. an internal rate of return sliding scale) have been achieved.

When it comes to capital allowances, South Africa's regime is relatively generous when compared to

[54] https://treasury.gov.au/sites/default/files/2019-03/R2016-001_PRRT_final_report.pdf

the 86 countries surveyed by EY in their global oil and gas tax guide (2019).[55] South Africa's regime includes immediate expensing in the year of investment for exploration and post-exploration, plus an uplift[56] of 100 per cent for exploration expenditure and 50 per cent for post-exploration expenditure (which includes development phase). None of the countries included in the survey that have transparent fiscal terms provide as beneficial treatment of capital expenditure. There may be countries that use PSCs which have more generous terms for some of their contracts, but that is not observable. Denmark provides a 30 per cent uplift on qualifying exploration during the exploration phase, but this is written off over 20 years. Italy provides a 40 per cent uplift for assets with amortization rates beyond 6.5 per cent. 16 countries provide immediate expensing for exploration-related capital expenditure, with 3 of these (Ireland, Kenya and the UK) also providing immediate expensing for capital expenditure in the development phase, but they do not provide uplifts in the form of additional deductions beyond what was spent. The rest of the 16 allow write-off of the assets over a number of years (e.g. 25% over 4 years) in respect of development capital expenditure.

[55] https://www.ey.com/en_gl/tax-guides/global-oil-and-gas-tax-guide-2019
[56] An uplift is a percentage of actual capital expenditure incurred, which is immediately deductible in addition to the amount spent on capital, e.g. an uplift of 100% means a 200% capital expense deduction

Box 1: The Fiscal Regime in Mozambique

The fiscal regime applicable to the petroleum industry in Mozambique consists of a combination of corporate income tax (CIT), royalty-based taxation and production sharing. The main elements are as follows:

• Corporate income tax rate — 32%

• Royalties — range from 6% to 10% and the base is determined as follows:

- For sales to nonrelated entities, the payable amount is determined based on the average sales price charged per barrel at the point of delivery, assessed with reference to free-on-board (FOB) prices.
- For sales to third parties under conditions different from FOB, an FOB price shall be applied calculated in the form of net-back, established by the deduction to the agreed price, of the effective and direct costs incurred by the concessionaire with compliance of the respective sale agreements.
- For sales to entities where the concessionaire is a shareholder, the price is agreed between the Ministry of Mineral Resources and Energy, the Ministry of Finance and the concessionaire.

• Bonuses — applicable under the public-private partnerships law, in which a signature bonus between 0.5% and 5% of fair value of assets applies; other bonuses might be paid, but they are not enshrined in law

• Production sharing — based on R-factor

Depending on the production sharing contract, government's share of revenues would be between 10% and 15% and will gradually increase to values ranging between 55% and 60% as the R-factor increases.

• Withholding taxes (WHT) — applied to dividends at the rate of 20 percent

• Resource rent tax — none

• Capital allowances are deducted on a straight-line bases on the following rates

- Expenses with exploration and appraisal — 100%
- Expenses with development — 25%
- Petroleum production assets — 20%
- Acquisition of petroleum rights — 10%
- Other assets — 10%
- Investment incentives — exemption from customs duties on the importation of equipment, machinery and tools

There is ring fencing per concession. However, if the taxpayer benefits from a partial exemption or a reduction in the tax rate, the losses of the activity that benefits from such incentives cannot be offset against the losses of the remaining activities.

Source: EY (2019) Global oil and gas tax guide

The remaining 70 countries fall into two categories. The first (a group of 41 countries) provides write-off periods for capital expenditure (in both the exploration and development phases) over a certain number of years. There is no information on the second (a group of 29 countries) – primarily because they use PSCs and each contract is negotiated separately, so the terms may differ. The lack of transparency makes it difficult to compare what these countries offer. A handful in this group simply do not have information available. Many of the countries that allow immediate expensing apply ring-fencing, as do some countries that apply normal depreciation write-off periods.

Many countries do not have fiscal stability clauses in their petroleum agreements. This is particularly the case in European and other OECD member countries. Many of these developed countries have lower levels of perceived and actual political risk. Of the 86 countries covered in this review, only 19 have a fiscal stability clause as shown in Table 6. Most countries with fiscal stability clauses use PSCs as a fiscal regime – they include Equatorial Guinea, Ghana, Guinea, Mauritania, Tanzania and Uganda. Cameroon, Chad, Kenya and Mozambique all use a combination of concessions and PSCs. South Africa, Papa New Guinea and Kazakhstan are the only countries using concessionary regimes that offer fiscal stability. In South Africa, fiscal stability is enabled by legislation at the Minister of Finance's discretion. Angola, Gabon and Mexico have a fiscal regime that includes PSCs, concessions and service contracts, with Côte d'Ivoire and Ecuador using a combination of PSCs and service contracts. Peru is the only country with a fiscal stability clause that is using a combination of concessions and service contracts.

Table 6: Countries with fiscal stability clauses by fiscal regimes

PSC	PSC + C	Concession (C)	PSC+C+SC	PSC+SC	C+SC
Equatorial Guinea	Cameroon	Kazakhstan	Angola	Côte d'Ivoire	Peru
Ghana	Chad	Papua New Guinea	Gabon	Ecuador	
Guinea	Kenya	South Africa	Mexico		
Mauritania	Mozambique				
Tanzania					
Uganda					

<u>Source</u>: EY 2019 and country legislation

The fiscal regimes of different oil and gas producing countries are evidently heterogenous and there are many factors to consider. The fiscal regime adopted by a country can either attract or deter investment, determine whether new projects can move forward and dictate company cash flows. The design of fiscal regimes, particularly in terms of their progressivity and the incorporation of elements such as windfall taxes, can mean that the level of fiscal take depends significantly on prevailing prices and costs.

7. South Africa – current regime

South Africa's current fiscal regime is a concessionary regime that imposes a combination of royalties and corporate income tax. The Tenth Schedule to the Income Tax Act outlines the taxation of oil and gas companies, while the Mineral and Petroleum Resources Royalty Act (MPRRA) imposes royalties.

The current royalty regime in the MPRRA classifies minerals and petroleum as refined or unrefined. The royalty base (gross sales) is based on the value at the first saleable point as it was difficult to ascribe a value to minerals or petroleum at the mouth of the mine or well head. There is a schedule in the MPRRA that lists specified conditions for each mineral. If a mineral is extracted and its condition is different to that specified, there is an adjustment to the tax base – gross sales. For oil and gas specifically, the first saleable point was determined to be "at the inlet to the refinery". Royalty rates are determined by profitability, but there is a minimum rate of 0,5 per cent to recognise that finite resources are being extracted and government should reap at least some reward. The rates increase to 5 and 7 per cent for refined and unrefined minerals, respectively. The ceiling rate for refined resources is lower to recognise that refined minerals have generally gone through more processing relative to unrefined minerals, so the value (royalty base) of the resource would be higher relative to that at the well head in the case of oil and gas. Oil and gas are classified as refined minerals with a rate of 0,5 to 5 per cent applying.

Oil and gas companies are taxed at the normal corporate tax rate and the Tenth Schedules states that the rate shall not exceed 28 per cent. The Schedule includes rules in terms of special allowances applicable to oil and gas, as well as rules pertaining to ring-fencing of assessed losses.

Exploration and post-exploration expenditure is allowed as a tax deduction (immediately expensed) when determining the taxable income of an oil and gas company. An exclusion to this rule is expenditure or losses incurred to acquire oil and gas right (unless participation treatment applies). Exploration and post-exploration of a capital nature qualifies for an uplift – 100 per cent in the case of exploration, and 50 per cent in the case of post-exploration capital expenditure. As a result, an oil and gas company may benefit from a total deduction of 200 per cent and 150 per cent of its capital expenditure related to exploration and post-exploration, respectively.

When determining taxable income, an oil and gas company is allowed to deduct all expenditure and losses (except acquisition cost) for exploration and post-exploration. Assessed losses from upstream activities can be set off against income from downstream activities, and 10 per cent of losses can be set off against any other income of the company (i.e. non-oil and gas income, such as investment income). Any losses thereafter can be carried forward to be offset against oil and gas income and income from the refining of gas.

Gains and losses (whether realised or unrealised) must be accounted for in the company's principle trading or functional currency (whether UK pounds or US Dollars) for tax purposes. Once taxable income and tax due have been calculated in the functional currency, the tax amount is then translated into rand at the average exchange rate for the year concerned for purposes of payment to SARS.

The rate of dividends tax on any dividend that is paid by an oil and gas company from amounts attributable to its oil and gas income is set at zero. Dividends paid from amounts other than oil and gas income, are subject to the standard 20 per cent dividend rate. The rate is subject to reduction under any applicable double taxation agreement. For example, the dividends tax rate applicable with respect to the United Kingdom, Netherlands and France can be as low as 5 per cent.

Withholding taxes on cross-border interest payments are applied at a rate of 15 per cent. In respect of interest paid on loans to fund exploration or post-exploration capital expenditure, the rate is zero.

Oil and gas operations require large amounts to be spent during exploration and development, which will only be recovered a number of years into the future. To provide oil and gas investors with certainty on the tax treatment of future revenues, the Minister of Finance may enter into a fiscal stability agreement (FSA) with an oil and gas company. The contract binds the government and guarantees provisions of the Tenth Schedule and the MPRRA as of the date that the contract is concluded.

The Income Tax Act makes available tax incentives that oil and gas companies may also benefit from, such as the research and development (R&D) tax incentive, learnership allowance, and employment tax incentive. The R&D incentive excludes R&D activities undertaken for the purpose of oil and gas exploration. However, expenditure incurred to develop technology used for oil and gas exploration may qualify for the R&D tax incentive. An oil and gas company may also claim an employment tax incentive aimed at encouraging employers to hire young and less experienced work seekers. In addition, a learnership tax incentive is available for registered learnership agreements that exists between a learner, an employer and a training provider.

The Tenth schedule contains rules that deal with the disposal of an oil and gas right. The disposal of an oil and gas right may result in a capital gain, rendering the oil and gas company subject to tax on those gains in the same manner as other companies. In disposing of an oil and gas right, the parties to the disposal may agree in writing that “rollover treatment” or “participation treatment” will apply. Rollover treatment and participation treatment apply if an oil and gas company disposes of any oil and gas right to another company where the market value of the right exceeds its tax value. Under rollover treatment, any tax gain from the sale of the right is eliminated (the transaction is tax-neutral) and the company that purchased the right is deemed to have acquired it at CGT base cost or the trading stock deduction that previously existed for the seller. If the parties agree to participation treatment, the seller treats all gains on the disposal of the oil and gas right as gross income and the purchaser is allowed to deduct from its oil and gas income an amount equal to the sum included in the seller’s gross income. The effect of electing into the participation treatment is that losses arising from oil and gas activities may be effectively transferred from the seller to the purchaser.

8. Which combination of tax instruments are best for South Africa’s oil and gas fiscal regime – a discussion

An excerpt from the Australian PRRT review in 2017 explains well the difficulty in finding an appropriate balance for all interested parties, as well as the importance of wide and intensive stakeholder involvement: “*It became clear during the course of the review that there are different views as to what constitutes an equitable return to the Australian community and what constitutes the discouragement of investment, along with the relative weight to be placed on either influence. Any assessment as to whether the PRRT is operating as intended or whether changes are required will ultimately come down to judgements after balancing a range of considerations*.”

This is true for all the policy design elements in respect of taxing the oil and gas sector. On top of determining a fair return for all parties (and determining what a fair share means given the different parties’ objectives), a further critical consideration is the context in which the industry operates. Due to the long project lead times, the political economy in each country shapes investor’s perceptions and is a crucial determinant of whether governments and investors can work together to generate maximum returns, with minimal negative impact on communities and the environment.

There will always be differing views – the goal of this discussion paper is to determine what the optimal tax regime should be in relation to the bill tabled by the DMRE. The intent is to ensure that both investors and the people of South Africa gain a balanced share from oil and gas exploration, while remaining mindful of South Africa’s commitments in respect of reducing carbon emissions.

History has shown that many governments have changed their regimes in response to both fluctuations in commodity prices and significant discoveries. This behaviour understandably causes hesitation on the part of investors to sink substantial capital. If the people of South Africa and investors are to reap the maximum benefits from our oil and gas resources, then a fair, transparent, efficient, as simple as possible, and certain fiscal regime is important.

8.1 The type of fiscal regime matters

Section 34 of the UPRD Bill explains the State's participation in petroleum rights. The 20 per cent carried interest that enables the State to retrieve its proportionate share of production (in cash or kind), reduced by the portion of costs recoverable by investors, is akin to a production sharing contract. While such contracts are used globally, this is a new concept for South Africa. At present, all companies make payments to the fiscus in terms of a concessionary regime.

At the outset, it is important to recognise that there might be some challenges that can arise from this type of arrangement. Doing so is imperative so as to minimise the risk of their occurrence. From a fiscal perspective, there are benefits to retaining a concessionary regime over introducing production sharing contracts. Some of the potential issues are outlined below, but most of them are remedied by the UPRD Bill.

Although there are several PSC models available, the drafting requires government negotiators to have sufficient knowledge of the costs and technical requirements of the oil and gas sector. Government needs to negotiate the best deal possible for the country. However, this is complicated by the cyclical nature of the oil and gas sector, which involves numerous contractual terms and inherent uncertainty in petroleum industries. These types of contracts can be opaque and difficult for the public or future investors to get details. Government prefers transparency.

Below are key considerations for ensuring the best outcome for South Africa in relation to production sharing:

- A concessionary regime allows the same treatment across all investors – something that PSCs do not as contractual terms may differ across investors. This is an important aspect for fair and equal treatment – an important tax policy design principle. The revised Bill takes this into account as the State participation requirement is standardised across all investors – it explicitly states that carried interest will be 20 per cent.

- Transparency is an important reason why a concessionary regime is better. This is an important point raised in a World Bank (2012) report: "*the lack of transparency in upstream contracting and signing of development agreements is a major constraint on effective revenue administration.*" The revised Bill also satisfies the transparency criterion as the UPRD Bill is clear in that every investor is required to carry a State participation of 20 per cent.

- Information asymmetry – the sharing of profits under a PSC is usually based on a formula and this formula is dependent on cost oil (a portion of produced oil that the operator applies on an annual basis to recover defined costs specified by a production sharing contract). Countries that implement PSCs have found that the system may encourage companies to inflate costs, to the detriment of Government's share in profit oil. To mitigate against this risk many PSCs have a cost recovery limit to ensure that government receives some revenues during production irrespective of the costs.[57] The UPRD Bill states that 50 and 100 per cent of the State's proportionate share of exploration and production costs, respectively, can be recovered from its share of production or revenue. This is not to say that the implementation of a tax regime is without challenges. For

[57]https://www.un.org/development/desa/financing/sites/www.un.org.development.desa.financing/files/2020-10/CRP51_%20Extractive_PSC_10-10-2020.pdf, p.15

example, transfer pricing is an area where investors can also alter the true cost or sales price in connected party transactions, but this is a challenge that South Africa has a lot more experience in relative to production sharing contracts.

- It is important that all revenues continue to flow to the National Revenue Fund via SARS. The World Bank (2012) raises important concerns in respect of regimes where revenue collection is fragmented across institutions: "*fragmentation in administration of revenues from the mineral sector, including the use of a state-owned corporation as a regulatory and revenue-collecting institution, without institutional incentives or enforcement mechanisms for coordination, inhibits successful tax administration reforms*". The State's proportionate share of net revenue (20 per cent of revenue less the costs that are recoverable by the investor) should flow to the National Revenue Fund for the benefit of the fiscus to be distributed to South Africans through public spending. Shifting the flow of funds to a state-owned entity means that revenue would be channelled away from potential enhancements to public spending and service delivery to the people of South Africa. Furthermore, SARS is much better placed to evaluate whether the government's share of revenue (based on its participation in petroleum rights) and costs are accurately determined in light of the challenges with asymmetric information – particularly if in relation to cross-border transactions between connected persons.

- While many low-income countries struggle with revenue administration capacity, SARS is best placed to administer tax revenues generated from tax instruments in the oil and gas sector. SARS has important skills from years of experience in mining taxation.

8.2 Fundamental tax principles to consider

Good tax policy analysis and design should be underpinned by a set of guiding principles. While there is no perfect fiscal regime, there are fundamental principles that guide government's thinking and analysis when designing a fiscal regime. These are equity (includes progressivity), efficiency, certainty, simplicity and revenue buoyancy. Importantly, not every tax instrument needs to meet every principle, but the tax system as a whole (with its combination of complementary tax instruments) should strive as far as possible to meet all these principles. When designing an oil and gas fiscal regime, there needs to be a balance between ensuring that the taxes imposed do not transgress tax neutrality (and discourage investment), while simultaneously enabling government to collect adequate and stable revenues.

Neutrality / efficiency

Neutrality refers to a fiscal regime that would not distort investment decisions. For example, a neutral fiscal regime seeks not to discourage an investor from exploring a variety of field sizes; alter project rankings; or interfere with production decisions. A tax aimed at collecting economic rent is considered to be optimal in this regard because the rent represents a return to the State not linked to measures to motivate investment in extraction[58]. In practice, neutrality is difficult to maintain as such a regime should provide relief for exploration costs and compensation for failed projects, which would be

[58]See A Raja 'Should Neutrality be the Major Objective in the Decision-Making Process of the Government and the Firm?' Centre for Energy, Petroleum and Mineral Law Policy 1999 Annual Review 3 – Article 2 available at http://www.dundee.ac.uk/cepmlp/car/html/car3_article2.htm (accessed 22 November 2010).

attractive to investors, but would impose significant risk exposure as well as some financial obligations to governments[59]. It is often easier to speak about neutrality in a theoretical context compared to achieving it perfectly in practice.

Progressivity

A progressive fiscal instrument based on profit (or a proxy thereof) increases the proportionate tax burden on companies as their profitability increases, and similarly decreases it as their profitability decreases. Regressive fiscal instruments like signature bonuses do the opposite. However, if governments relied solely on a progressive tax, like a resource rent tax that is based on a sliding scale of returns, revenues would be pro-cyclical – thus amplifying the revenue effects of higher and lower profitability, and inducing heightened volatility into future revenue flows.[60]

Certainty

Certainty or stability can be thought of from two perspectives. For an investor, a tax system subject to various changes tends to undermine investors' confidence and raise investment hurdles to compensate for increased risk, thereby reducing the value investors place on future income streams. Government and investors face a number of risks related to oil and gas projects. Fiscal stability boosts investors' confidence in government policy, enhances the regime's appeal for new investment and secures the basis on which investors made prior decisions. While stability of the fiscal regime is desirable, circumstances are constantly changing. Governments and contractors may therefore need a certain degree of flexibility to adapt the fiscal regime to differing conditions and to evolving factors such as geology.

From a government perspective, stability of revenues or the ability to estimate future tax revenue streams is important. For this reason, governments tend to use instruments such as bonuses and royalties that guarantee a certain level of income for government as soon as production starts – regardless of profitability. Furthermore, while constant changes are not ideal, it is government's prerogative to amend the fiscal regime should it no longer be appropriate for current circumstances.

Simplicity

A simple fiscal regime is characterised by tax policy that is simple to understand for all stakeholders. Administrative simplicity that is in line with the institutional capacity of the tax authority regarding the oil and gas industry is important. Simplicity increases transparency and reduces the administrative and compliance burden for tax administrations and investors.

There are sometimes tradeoffs between different principles and perfectly balancing these tradeoffs can be tricky, but the ultimate aim is to instill investor confidence so that investment is encouraged and both government and the investor share in the rewards.

8.3 Modelling of fiscal regime options

National Treasury has used a model to compare and evaluate a number of fiscal regimes. The first

[59] Daniel et. al. (2010) p190
[60] Daniel et. al. (2010) p251

regime is the status quo, which is based on the MPRDA and Income Tax Act. The second is based on the Upstream Petroleum Resources Development Bill, with no changes to the Income Tax Act. A further set of regime options are also based on the UPRD Bill, but seek to show how changes to the tax regime would affect the share between government and investors, based on a set of assumptions and scenarios. For example, the model allows variation in the oil price, field size (estimated reserves), and operational and capital costs.

Table 7 outlines the geological and economic assumptions, and options in the model. This is an area where we would benefit from the oil and gas industry's constructive comments. While government fully understands the heterogeneity inherent in this industry, it is still valuable to be able to compare regime options based on certain inputs (e.g. trying to isolate how the oil price or estimated reserves influence the outcome for all parties).

Table 7: Important information about the model

Customisable field	The modelled field is customisable and allows the estimated reserves to vary.
3 estimated reserves scenarios (for custom field)	The following three recoverable reserve estimates for 3 hypothetical fields are included: • 100 mmboe • 200 mmboe • 900 mmboe These estimates are all measured in millions of barrels of oil (energy) equivalent (mmboe). It is important to note that the first two are P50 (probability of 50%) / "best guess" estimates provided by PASA, and the third represents the potential for a large find. Estimates change with increased and better information. For example, initial geological and geophysical interpretation of a particular field and the surrounding prospects is often done using 2D seismic data. This is like trying to build a 3D model of the interior structure of a rock's layers with only one or two slices through the area. Having 3D seismic data for an area makes the building of a 3-dimensional model much easier and enhances understanding of the reserve potential. While there are exceptions, reductions in resource size with increasing data is the norm in the oil industry. The less data, usually the bigger the estimate. 3D seismics, drilling, and flow tests enable a better sense of reality, while production to depletion is the only true measure.
Length of phases in lifecycle of project (custom field)	The model assumes the following: • Exploration (5 years) • Appraisal (4 years) • Final investment decision (FID) occurs in year 10 • Development (5 years) • Production (20 years) The estimated reserves are assumed to be produced over a 20-year period, ranging from 1-9 per cent of estimated reserves per year.
Oil prices	Three oil price scenarios are included, based on the IMF World Economic Outlook (WEO) projections: • USD 40/boe • USD 60/boe • USD 80/boe
Gas prices	This is tricky to estimate given that gas prices are generally determined on a regional basis and South Africa has no established market and infrastructure for gas at this point. For this reason, a simple average of the IMF WEO projections for 2021 in respect of the following 3 prices was used:

	• Russian Natural Gas border price in Germany, US$ per million metric British thermal units (MMBtu) of gas • Indonesian Liquified Natural Gas in Japan, US$ per MMBtu of liquid • Natural Gas spot price at the Henry Hub terminal in Louisiana, US$ per MMBtu of gas The simple average estimate for 2021 is USD 4.2 per MMBtu of gas/liquid However, the model uses million standard cubic feet (mmscf) for production volumes in the two specific fields and pricing in USD/mmscf. Therefore, the USD 4.2 per MMBtu is multiplied by 0.9756 to obtain an estimated gas price of USD 4.1 / mmscf. The conversion rate was obtained from: https://business.directenergy.com/understanding-energy/energy-tools/conversion-factors
Discount rate	This will differ by company and by project. The model uses 8 and 10 per cent as the discount rate (the results presented are based on 10 per cent). Both revenue and borrowing are likely to be in USD, which would provide reason to have a lower discount rate (relative to using ZAR). A company with investors primarily from Europe and/or the United States would likely have a lower weighted average cost of capital relative to South African companies. The SA government bond (R183) currently has a yield of around 10%. The IMF used a range of 5 to 12.5 per cent in its modelling. It is considered appropriate to include a risk premium given the developing country context and uncertainty surrounding oil prices (for various reasons, including environmental).
Capex (USD/boe)	The model allows for 2 capital expenditure options: • USD10/bbl (this is just higher than the average for Africa) • USD20/bbl These were originally based on 2014 information and some companies' annual reports suggest these have come down. However, the industry is still in a nascent phase in South Africa and there is a lack of existing infrastructure. These numbers were checked with PASA and some companies' reports[61].
Opex (USD/boe)	The model allows for 2 operating expenditure options[62]: • USD5/bbl (this is in line with the average for Africa) • USD10/bbl
Dividends	The dividend pay-out ratio is assumed to be 35 per cent of after-tax accounting profit
Corporate tax rate	28 per cent
State participation in rights	• Company takes 70% of revenue (or production) • State takes 20% of revenue (or production) • Company bears 70% of the costs (plus 50 per cent of the State's share of exploration costs) • State bears 10% (half its share) of capex for exploration • State bears 20% of operating expenditure and capital expenditure in respect of production • BEE participates at 10%
Carried interest	The State's cumulative carried interest is reduced over time starting when production commences. The State pays its share of the costs by deducting the difference between its revenue share and cost share from the start of production, and doing so until the carried interest is paid for.

[61] For example, https://www.rosneft.com/upload/site2/document_file/pdf_1213052016_en.pdf

[62] These numbers were checked with PASA and some annual reports, e.g. https://www.shell.com/investors/financial-reporting/quarterly-results/quarterly-results-2018/q2-2018/_jcr_content/par/textimage_400875472.stream/1532703745866/6790c7e30ed2a8f3f4dd5a44f2eea83cb68b6297/q2-2018-slides-final-media-analyst-clean-with-updated-hse-slide.pdf

Table 8 provides an overview of the different regimes that were tested.

Table 8: Overview of fiscal regime options included in the model

	Potential Regime	Description relative to current legislation
1.	Current MPRDA	• Status quo for mining and tax legislation
2.	UPRD Bill	• The State's participation share (through a carried interest) in petroleum rights is 20 per cent • Cost recovery for investors is 50 and 100 per cent in respect of the State's proportionate share of exploration and production costs, respectively.
3.	Package 1: UPRD Bill plus standard royalty rate	• Governing legislation as stated in item 2 • Current royalty design changed to a flat royalty rate of 5% applied on the same base • Dividends tax increased to standard rate of 20% (but would be affected by relevant treaties – the model assumes a rate of 5%)
4.	Package 2: UPRD Bill plus reduce uplifts fully	• Governing legislation as stated in item 2 • Exploration uplift reduced from 100% to 0. • Post-exploration uplift reduced from 50% to 0. • Dividends tax increased to standard rate of 20% (but would be affected by relevant treaties – the model assumes a rate of 5%)
5.	Package 3: UPRD Bill plus standard royalty & reduce uplifts fully	• Governing legislation as stated in item 2 • Royalty design changed to a flat royalty rate of 5% applied on the same base • Exploration uplift reduced from 100% to 0. • Post-exploration uplift reduced from 50% to 0. • Dividends tax increased to standard rate of 20% (but would be affected by relevant treaties – the model assumes a rate of 5%)
6.	Package 4: UPRD Bill plus Tweaked royalty & reduce uplifts fully	• Governing legislation as stated in item 2 • Retain current royalty design, but increase rate range from 0.5-5% to 2-10%. • Exploration uplift reduced from 100% to 0. • Post-exploration uplift reduced from 50% to 0. • Dividends tax increased to standard rate of 20% (but would be affected by relevant treaties – the model assumes a rate of 5%)

The results presented in the graphs to follow are based on the following assumptions for the custom field:

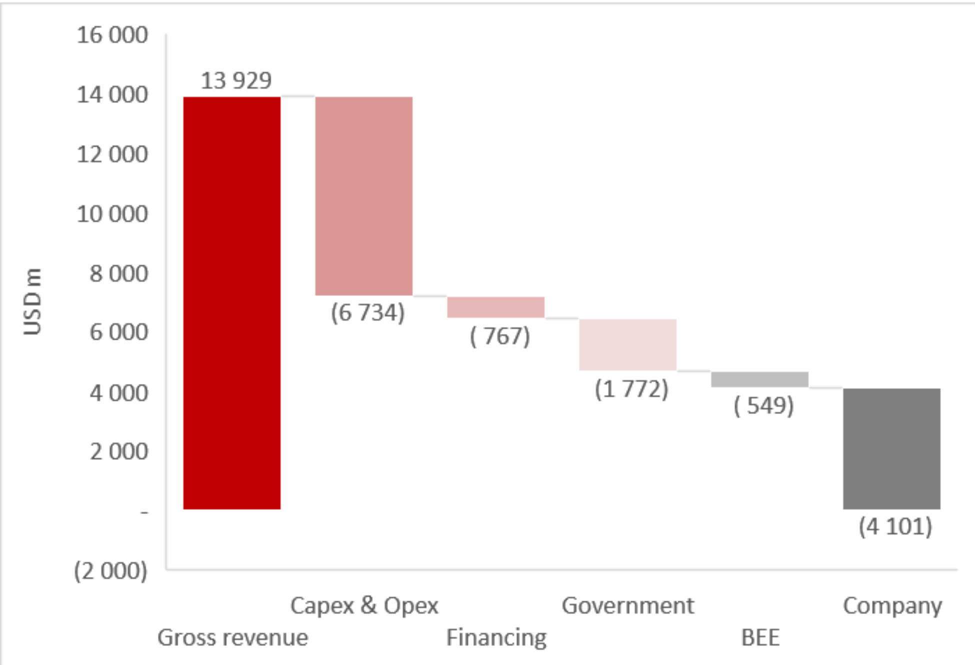
- Field based on P50 estimates from PASA (200 mmboe)
- Gas condensate with price equivalent to oil in USD/boe (prices for gas condensate can be lower/higher than the oil price)
- Oil price is USD 40/60/80 boe (inflation at 1 per cent for 16 years and held constant thereafter)
- Capex is USD 20/boe
- Opex is USD 10/boe

The assumptions with respect to the estimated reserves and costs are considered to be conservative in that they represent the higher cost assumption (to recognise that this industry is in a nascent phase in South Africa, which will require extensive spending on infrastructure – particularly if in deeper, unchartered waters). The estimated reserves are seen as a mid-range estimate. After the results for each potential tax regime change has been presented based on these cost and reserve assumptions, a set of NPVs are presented under different cost and reserve assumptions to show how these two factors can sway investment decisions.

Initially these two inputs (estimated reserves and costs) are kept constant to enable a comparison of two important factors – changes in the regime and commodity prices. All amounts presented are in USD.

Figures 10 and 11 show how the overall revenue from a hypothetical investment would be distributed assuming an oil price of USD 60. Figure 10 shows the status quo – i.e. the application of the MPRDA and the Income Tax Act – while Figure 11 shows how the distribution changes under the UPRD Bill (no changes to the Income Tax Act). The change from the MPRDA to the UPRD Bill results in a shift in the government-to-investor take ratio. Without amending the tax regime, the change from the MPRDA to the UPRD Bill leads to an increase in government's share. The extent to which the balance shifts depends on other factors – including the extent of estimated reserves and the oil price. Under the current regime, the government and investor shares are 28 and 64 per cent respectively (the remainder is attributable to a BEE partner). A shift to the UPRD Bill increases government's share to 36 per cent, while the investor retains 56 per cent.

Figure 10: Revenue Distribution – Mineral and Petroleum Resources Development Bill



Comparing the estimated government and investor share is not the only basis on which to compare regime designs. When deciding whether to invest or not, investors also consider the net present value (NPV) of potential projects. NPVs are influenced by estimated reserves, oil prices, costs, regime design and discount rates. Both regimes yielded a negative NPV value under the assumptions presented (with an oil price of USD 60). If an oil price of USD 80 is modelled instead, both NPVs turn positive.

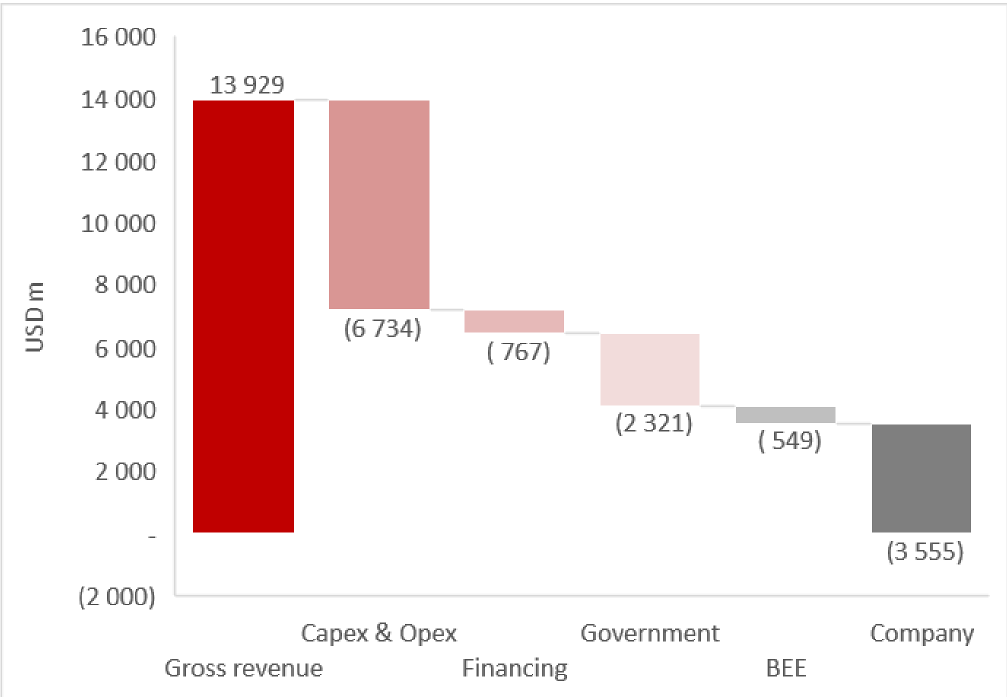
USD 80 was used as the upper bound for the modeling exercise. The global economic effect of the Covid-19 pandemic has shown how low oil prices can drop. For this reason, a lower bound of USD 40 was used.

The rest of this section discusses the estimated effects of revising the tax regime for the upstream petroleum industry. All potential tax regime changes are modelled alongside the UPRD Bill.

The model incorporates two potential changes to the royalty design – one option increases the minimum and maximum rates of the current royalty rates from 0.5 and 5 per cent to 2 and 10 per cent, while the other option introduces a flat 5 per cent rate on the same gross sales tax base. The second option was tested given IMF's concerns on the current royalty regime for oil and gas in particular, i.e. that the royalty design is unnecessarily complex.

The IMF conducted a modelling exercise to advise the Davis Tax Committee (recommendations from the IMF and Davis Tax Committee are included in Annexure B). Their model included oil fields of 500 million and 1000 million barrels – substantially higher than the best-guess estimates from PASA. The base case scenario for the oil price at the time was based on the 2015 IMF World Economic Outlook forecasts. The lower and upper bounds were 50 USD and 80 USD/bbl respectively. The larger reserves included in their model resulted in the royalty rate reaching the ceiling of 5 per cent as soon as production started. It is important to take note of these different underlying assumptions when reading the IMF's recommendations.

Figure 11: Revenue Distribution – Upstream Petroleum Resources Development Bill



The IMF (2015) report made the following conclusions:

- *"This scheme is unusual for a petroleum royalty and produces a low minimum take by comparison with jurisdictions outside the OECD (and some inside)*
- *Most royalty or production sharing schemes in emerging market or developing countries provide for a significantly higher minimum share of gross proceeds to go to the state*
- *Countries such as the UK, Norway or Australia, which no longer impose royalty on offshore production, had minimum royalties in effect during the first decade or more of petroleum production*
- *Offshore field discovery targets are large and probably capable of a minimum payment whenever*

petroleum is extracted

- *The mission's simulations show any success case moving up to the five per cent rate very soon after the start of production*[63]
- *The formula royalty is an unnecessary complication and should be replaced (if production-sharing is not used instead) with a flat rate royalty on the gross value of production at the delivery point from offshore field facilities of at least five percent."*

Figure 12 shows the effect of introducing a standard royalty rate of 5 per cent to replace the current royalty design (where the rate is determined by profitability and ranges from 0,5 to 5 per cent). Implementing this for the custom field at an oil price of USD 60 increases government's take to 41 per cent and reduces the investor's take to 51 per cent. However, the estimated NPV for this case is negative. Applying an oil price of USD 80 yields a small negative NPV.

Figure 12: Revenue Distribution – Package 1: UPRD Bill plus standard royalty rate

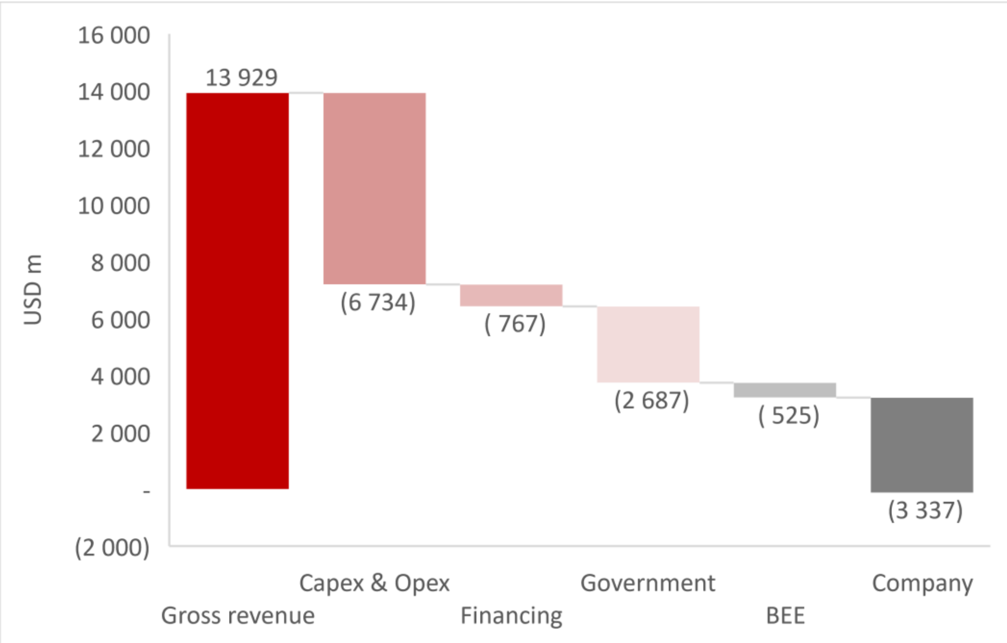


Figure 13 shows the effect of removing the special uplifts so that immediate expensing would occur with no additional deductions. Implementing this for the custom field at an oil price of USD 60 increases government's take to 48 per cent and reduces the investor's take to 45 per cent. The estimated NPV for this case is also negative for oil prices set at USD 60 and USD 80.

[63] The IMF modelled larger reserves and higher oil prices than those used in our analysis.

Figure 13: Revenue Distribution – Package 2: UPRD Bill plus no uplifts

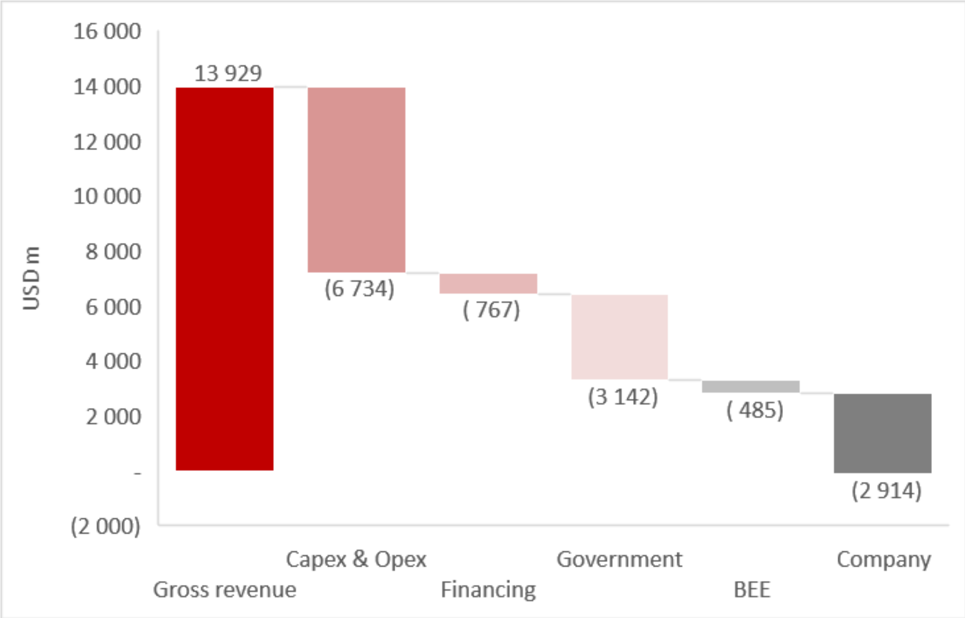


Figure 14 shows Package 3 (the combined effect of Package 1 and Package 2), where a standard royalty is imposed in conjunction with removing the special uplifts. Again, the distribution tilts in government's favour (50 per cent relative to 42 per cent for the investor), but the likelihood of investment in the hypothetical example is not high given negative NPVs for oil prices at USD 60 and USD 80.

Figure 14: Revenue Distribution – Package 3: UPRD Bill plus standard royalty and no uplifts

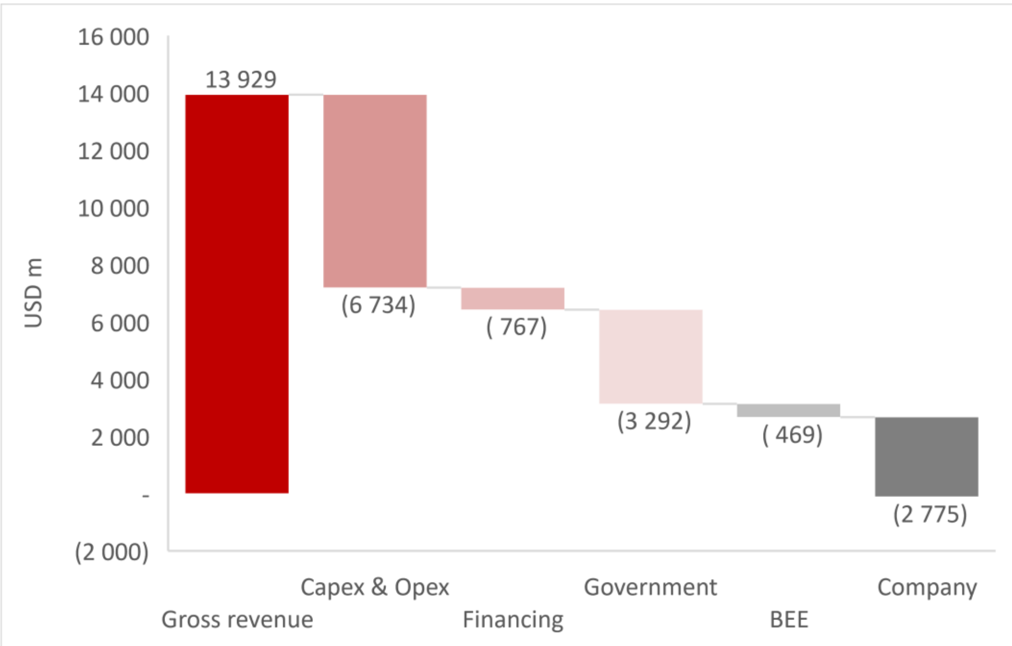
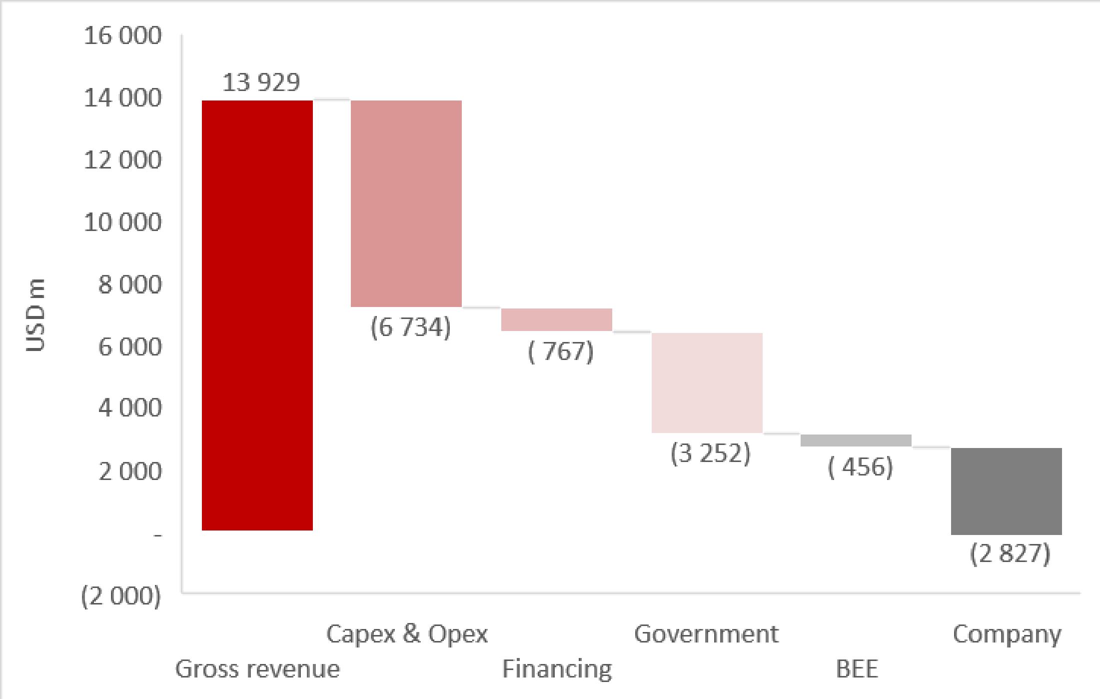


Figure 15 shows the estimated distribution for Package 4, which yields a similar outcome to package 3. Here, the royalty design remains the same, but the range for the rate is increased from 0,5 to 5 per cent to 2 to 10 per cent.

Figure 15: Revenue Distribution – Package 4: UPRD Bill plus tweaked royalty and no uplifts

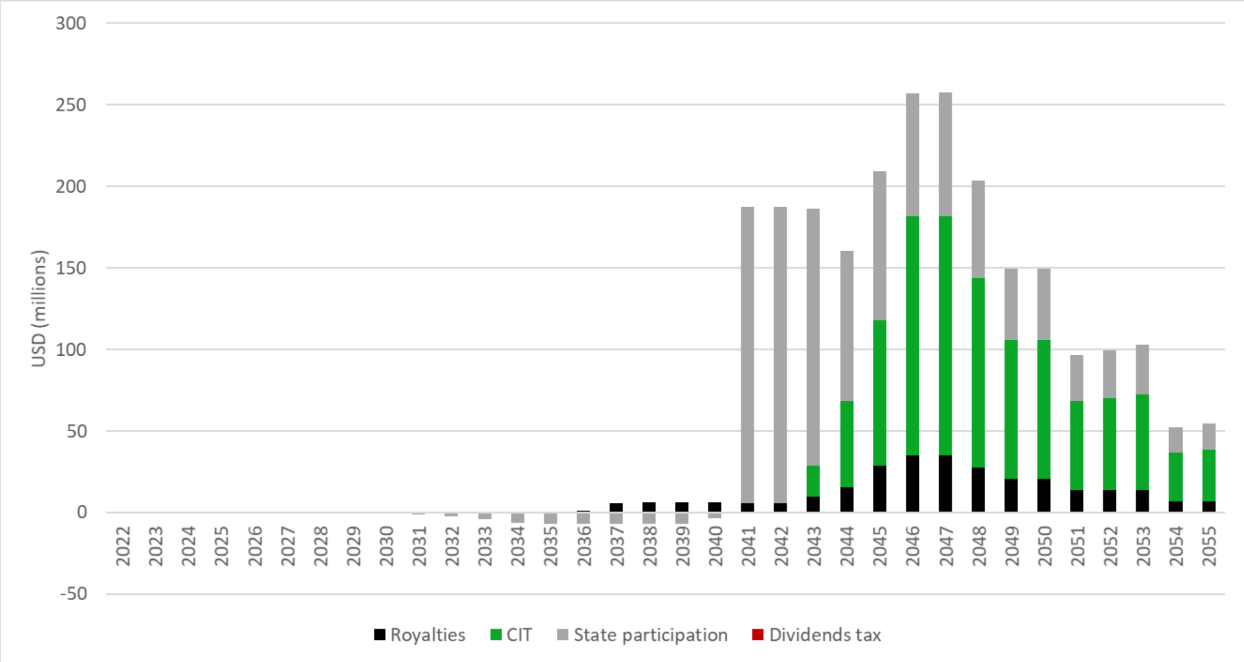


It is also important to consider the profile of estimated tax revenue streams. Flat-rate royalties would mean more upfront revenue for government relative to the current design based on profitability.

Retaining the current royalty design would help companies as it takes costs into account, but is complex. Revenue from a flat-rate royalty would generally follow the pattern of production and commodity prices. Furthermore – the net revenue from production sharing, along with revenue generated from royalties and CIT, are determined by profits, so are procyclical. Flat rate royalties provide a more stable, guaranteed revenue source upfront. Importantly, neither type of royalty would provide a structural increase in revenue as oil and gas reserves are finite and will be depleted at some point. This is a good reason why this type of revenue stream is well suited for contributing to a sovereign wealth fund (a good revenue source to assist with long-term fiscal sustainability).

Figure 16 shows the estimated government revenue profile for the hypothetical project under the UPRD Bill with no tax changes, at oil prices of USD 60. The first ten years consist of exploration and appraisal with the final investment decision taking place in year 10. Following this is a few years of development before production starts in 2036. Both royalties and corporate income tax collections only start making a difference about 22 years in when the project becomes profitable (around 2043). Both are based on profit so rise and fall with commodity prices, the extent of production and costs.

Figure 16: UPRD Bill – Government revenue - tax, royalties and state participation (no discount factor)



The grey bars represent the revenue received by the state from its 20 per cent participation in the petroleum right. In this hypothetical investment case, production starts in 2036 and it takes five years for the State to pay back its share of costs before being able to receive its proportionate share of positive net revenue from 2041. The negative grey bars represent the State's share of interest expense.

Figure 17 shows how the revenue profile changes if a standard royalty rate of 5 per cent is implemented. The difference here relative to Figure 16 is the increase in revenue in the initial years of production as the royalty is based purely on sales rather than its rate being determined by profits. Royalties are deductible from taxable income.

Reducing or removing the generous uplifts would bring corporate tax revenue forward (which would mean larger green bars in earlier years). This is another design element the IMF commented on. Because the uplifts are different for different phases, a concern was raised that companies could try to classify capital expenditure as being for exploration rather than post-exploration given the larger uplift for applicable to the former phase. It also pointed out that South Africa's uplifts are the most generous in the world – a fact corroborated by the international review conducted.

Figure 17: Package 1 – Government revenue - tax, royalties and state participation (no discount factor)

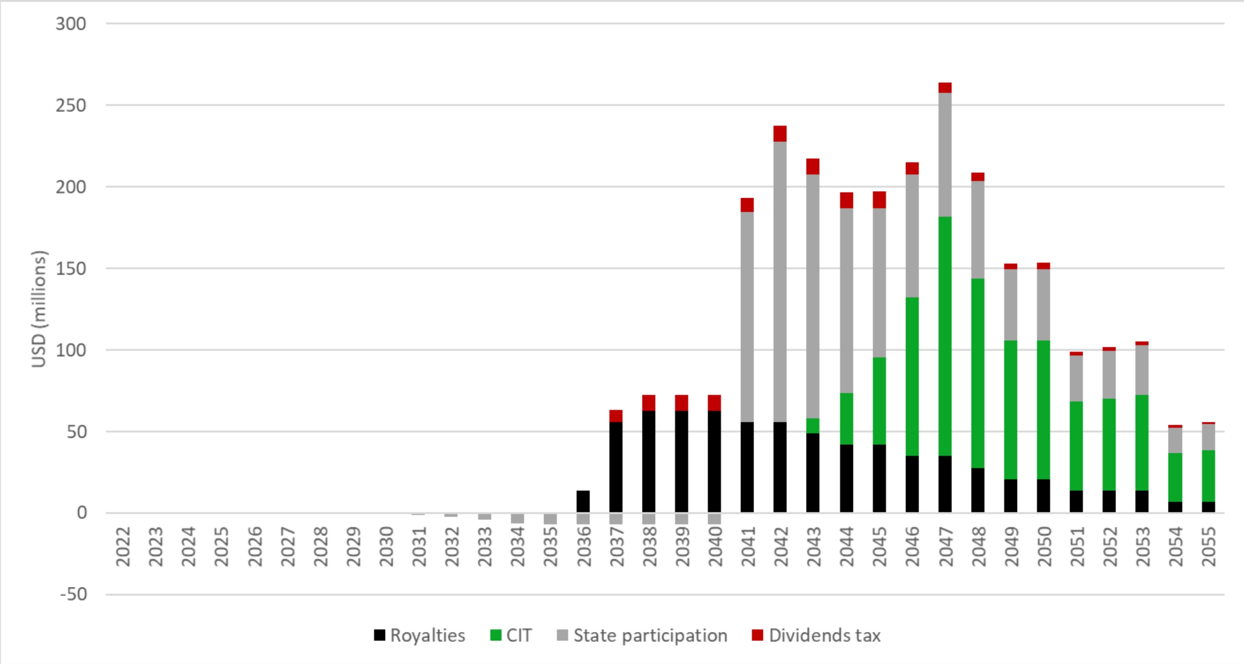
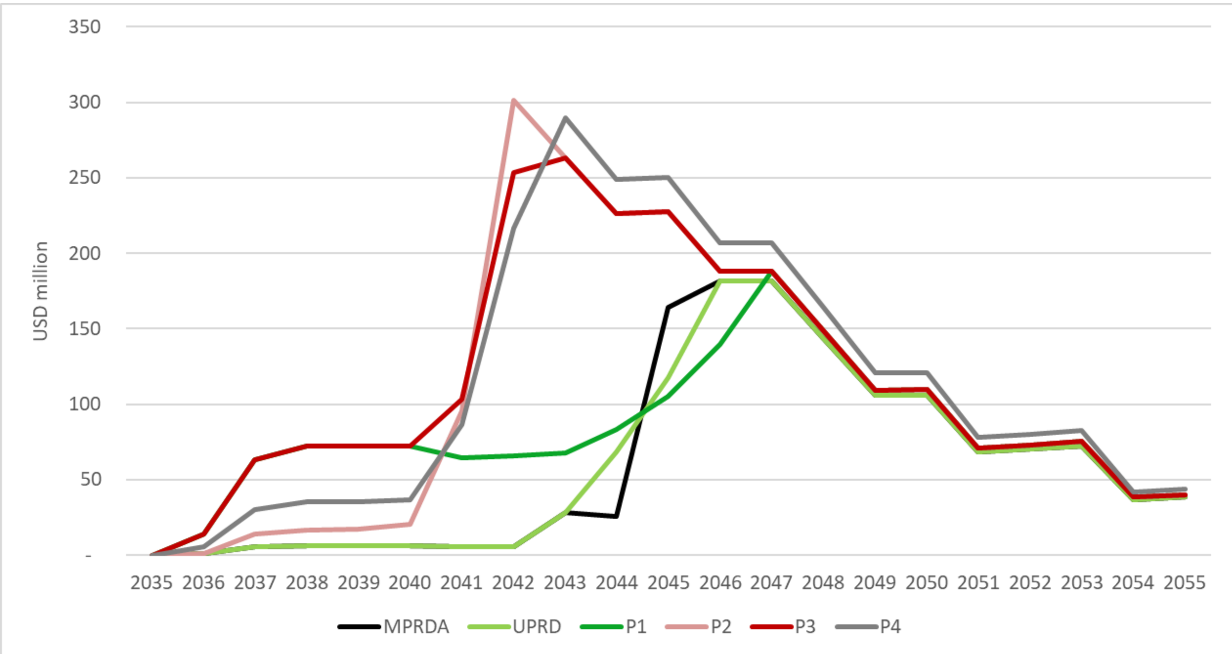


Figure 18 shows the combined tax and royalty revenue for each regime based on the hypothetical example.

Figure 18: Estimated tax and royalty revenue profiles by fiscal regime



One of the measures investors use to determine the viability of a project is the net present value. For the specific field used for illustration (with 200 mmboe), Figure 19 shows the estimated NPVs for three oil prices – USD 40, 60 and 80. The only two regimes that do not yield negative results, and which require an oil price of USD 80, are the MPRDA and UPRD Bill with no accompanying tax changes.

Figure 19 shows estimated NPVs for different tax regime options based on a high-cost, medium-reserve assumption. The high cost scenario assumes capital expenditure to be USD 20/boe and operating expenditure to be USD 10/boe, while the estimated recoverable reserves are 200mmboe. Sensitivity analysis is important to consider how the NPVs could change under difference cost and reserve assumptions. Figures 21 and 22 show estimated NPVs for two additional scenarios.

Figure 19: Estimated NPV values by fiscal regime and oil price (high-cost, medium-reserves scenario)

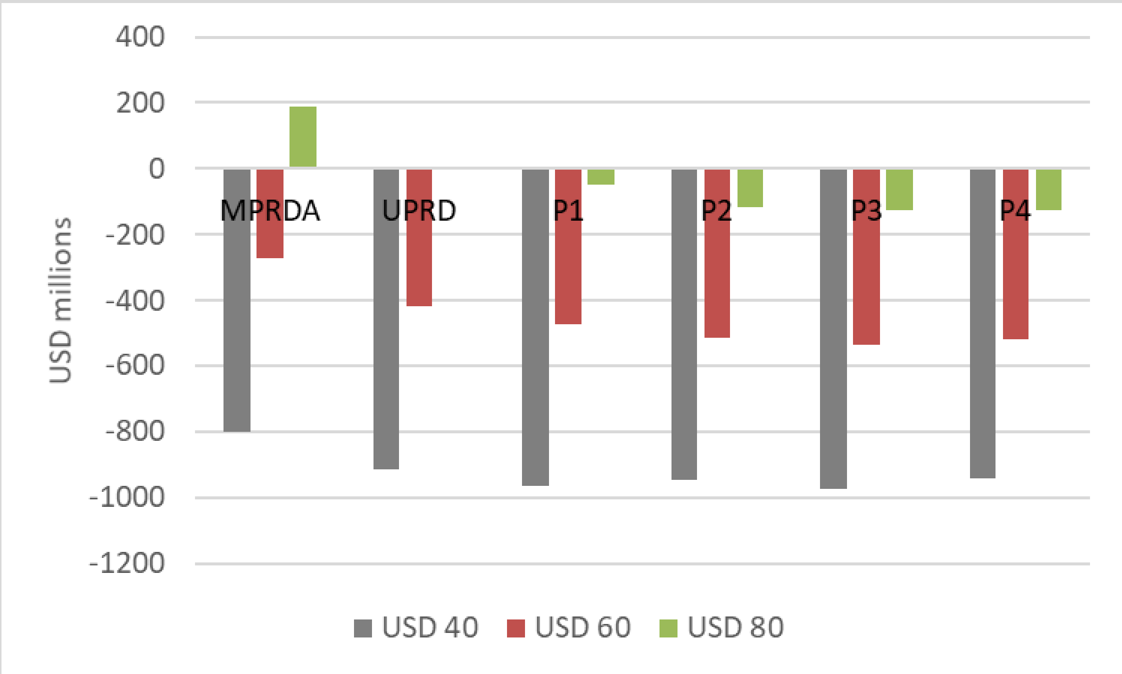


Figure 20 shows the estimated IRR values assuming a field with 200 mmboe and the three oil prices.

Figure 20: Estimated IRR values by regime and oil price

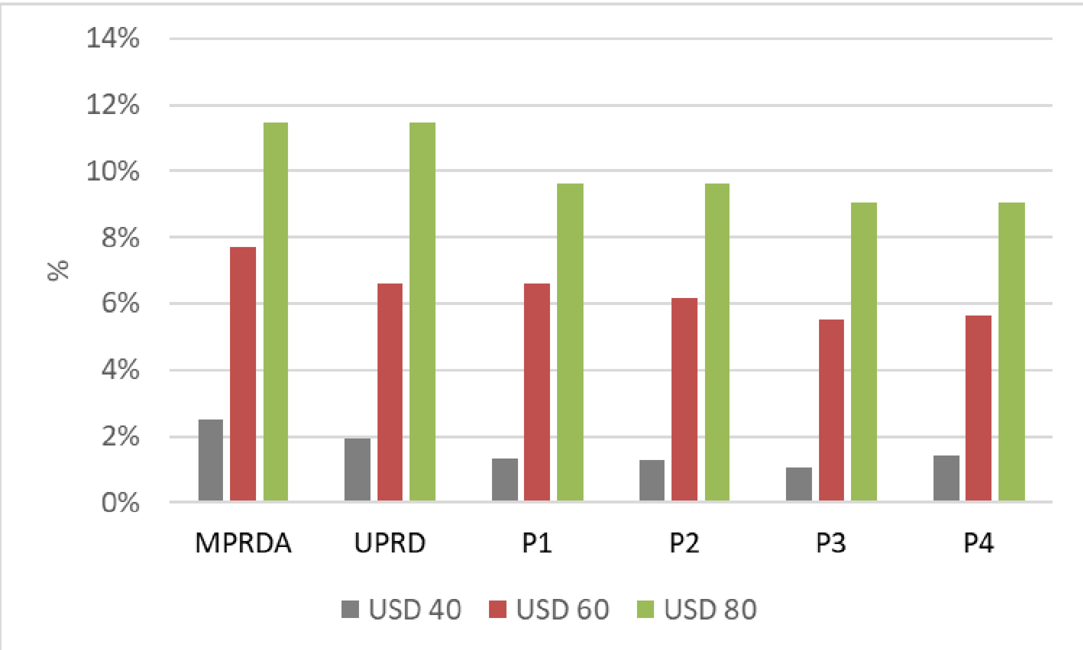


Figure 21 shows a low-cost, medium-reserve scenario. The only assumption that has changed relative to Figure 20 is the cost element – capital expenditure is now assumed to be USD 10/boe while operating expenditure is USD 5/boe. Under these assumptions, from oil prices of just below USD 60, all of the tax regime options would yield positive NPVs.

Figure 21: Estimated NPV values by fiscal regime and oil price (low-cost, medium-reserves scenario)

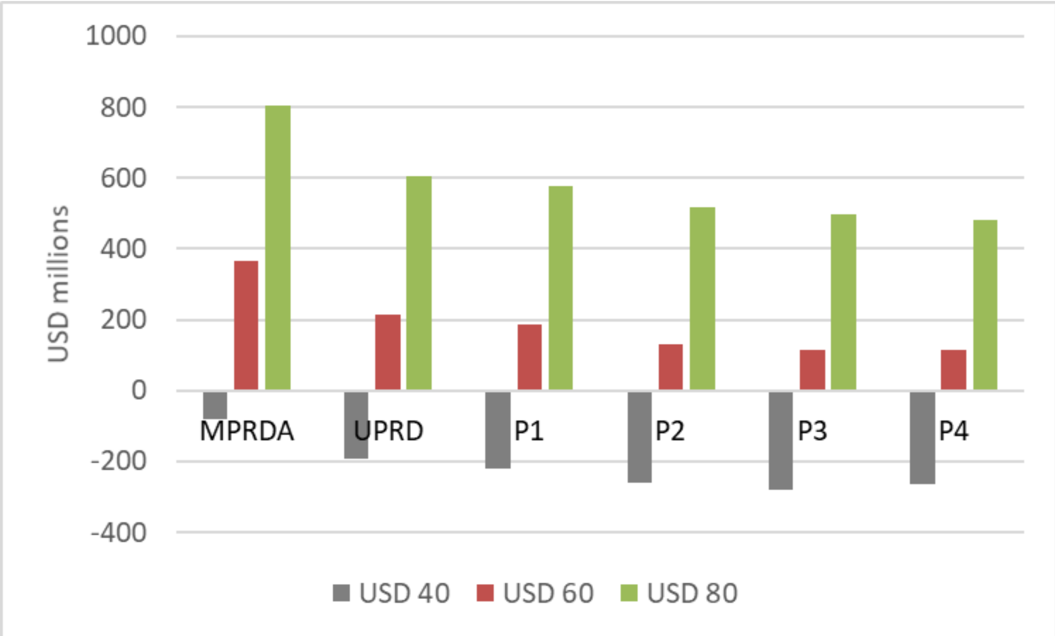
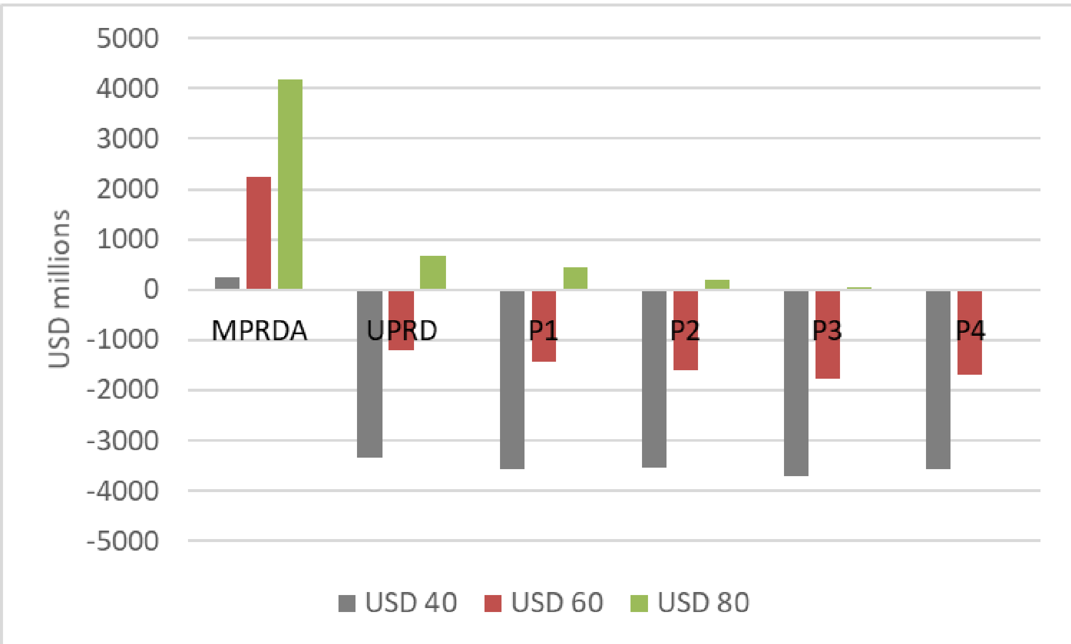


Figure 22 shows the outcome for a high-cost, high-reserve scenario. The high reserve scenario assumes a field with 900 mmboe that is recoverable. Figure 22 shows that even if reserves are on the higher end, higher costs that are measured per barrel of oil equivalent can mean that drilling may not be viable.

Figure 22: Estimated NPV values by fiscal regime and oil price (high-cost, high-reserves scenario)



In contrast, if a field has high reserves and the lower cost scenario, an oil price of USD 46 is enough for all tax regime options to turn NPV positive.

In summary, the analysis shows that government's take from upstream petroleum projects will increase as a result of implementing the Upstream Petroleum Resources Development Bill. This is due to the hybrid-type model where the current concessionary tax regime is combined with a production sharing arrangement that is uniform across investors as it is captured in the legislation (rather than drafted into individual contracts). The UPRD Bill stipulates that the State is entitled to a 20 per cent carried interest in petroleum rights, and will benefit by receiving its proportionate share of production / revenue.

The increase in the government's take means a reduced take for the investor relative to current legislation, which reduces the NPV and IRR of each project relative to the MPRDA scenario. Making changes to the tax regime would reduce the NPV and IRR of each project further. However, the modelling exercise clearly shows the importance of oil prices, recoverable reserves and costs in driving decisions.

8.4 Options considered in working towards an optimal tax regime

The current tax regime for the oil and gas industry is generous and was designed at a time when there was little interest in exploration. Times have changed since then and, while it is important not to amend the fiscal regime continuously, it has been 15 years since the Tenth Schedule was enacted. More is known about the resource potential now than at that stage. It is important to evaluate aspects of the tax regime, as well as its overall design, on a periodic basis to ensure it is in line with South Africa's economic objectives.

The Minister of Finance announced in the 2020 and 2021 Budgets that the corporate tax regime is being revised to work towards greater efficiency and a more uniform tax treatment across taxpayers, sectors and sources of finance. Part of this review involves the evaluation of tax incentives to ascertain whether they are achieving their stated objectives and whether they are still aligned to government's objectives. The Tenth Schedule to the Income Tax Act, which carves out special treatment for the oil and gas sector, can be considered a tax incentive. While the tax regime is considered generous by international standards, the tax regime alone cannot encourage exploration and/or investment activities. Investors consider a range of factors when deciding to explore and invest. In addition to reviewing the corporate tax regime holistically, it was initially announced in the 2019 Budget Review that the oil and gas tax regime would be reviewed.

In the extractive industries context, governments are always faced with the challenge of how to attract investment without making unnecessary fiscal concessions that will substantially impair long-term revenue prospects. A progressive and flexible regime that responds to changes in profitability should be attractive to investors given that higher rates are triggered only if a project becomes relatively more profitable. This needs to be balanced with simplicity and ensuring that the State receives at least a minimum compensation for the loss of its finite resources.

One crucial objective – based on all the lessons from other countries through history – is to design a regime that caters for times of both low and high oil and gas prices. Prices are notoriously hard to predict – hence the need for a stable, yet flexible policy design – one that guarantees South Africa a minimum payment in return for extraction of its depletable resources (even when prices are low), but is simultaneously mindful of investors' costs and how they drive investment decisions. When prices are high, both South Africa and investors should be able to enjoy the benefits – the former because its finite resources have been depleted (and the people living in South Africa should enjoy the benefits) and the latter because significant financial outlays and physically extracting the resource deserve a return. In addition to balancing the take for state and investor, balance is also required between incentivising investment, meeting South Africa's climate commitments and protecting the environment. Working within this overarching balancing framework will negate the desire for government to impose more stringent terms in the event of a surge in prices – as we have witnessed in history.

Tradeoffs in choosing fiscal instruments is inevitable. Governments tend to combine instruments to overcome the tradeoffs between efficiency and effectiveness in revenue raising, or between revenue adequacy and variability implied by the different instruments. Besides creating different incentives for extraction, grade selection, and differences in terms of deadweight loss, the different tax instruments also affect the variability or uncertainty of government revenues. The uncertainty in revenue streams flowing to the government imposes a cost on the economy. From a government perspective, taxes with less variability in government revenues are more desirable than those that create higher uncertainty. From this perspective, output-related taxes are preferable to income-based taxes. Income tax revenues depend on more than just the quantity extracted and price of output – they are also affected by the prices of inputs and cost overruns, for example. While the revenue stream from income taxes has a high variability, the variability of a combination of income tax and royalty (assuming output-based) lies in between and is moderate compared to a pure income tax. An additional profits tax or resource rent tax results in multiple rates with a more variable revenue stream.[64]

Each of the tax instruments that were considered in the international comparison; discussed in the document; and tested within the potential tax regime packages included in the economic modelling exercise are discussed below. The sections that follow include the Government stance on each instrument. Following this is a proposal for adapting the tax regime for oil and gas companies.

a. Royalties for oil and gas

The current royalty regime classifies minerals as refined or unrefined. Oil and gas are classified as refined minerals. The royalty base (gross sales) is based on the value at the first saleable point, which is described as "at inlet of refinery". The royalty rate applied to the base ranges from 0.5 to 5 per cent for refined minerals (including oil and gas), depending on profitability.

The IMF considered the formula royalty an unnecessary complication that should be replaced with a flat royalty rate of at least 5 per cent on the gross value of production at the delivery point from offshore field facilities for the oil and gas industry. The Davis Committee agreed that a flat royalty would make the determination of the royalty simple and easier for both revenue authority and taxpayer to administer, in the context of petroleum resources.

The international review revealed that the minimum rate of 0.5 per cent is low by comparison to other countries. It appears that there is a trend towards applying higher royalty rates on oil relative to gas. This could be due to the fact that cash flow in respect of oil turns positive more quickly and can be steeper (upward) than gas. There are no uniform rates for countries with concessionary regimes, for example, Germany has the highest royalty progressive rate that ranges from zero to 40 per cent and

[64] World Bank (2012)

Netherlands has the lowest rates ranging from zero to 7 per cent (see Table 9 in Annexure C). Some countries also have differentiated rates based on conventional versus unconventional extraction; or shallow versus deep water.

There is a useful discussion on varying the rates between oil and gas by Kellas (2010) in Daniel, Keen and McPherson (2010). They present a few factors to consider. It matters what type of gas is retrievable – i.e. whether it is associated gas found with oil or whether it is gas in a liquid form, such as condensate. They argue that condensate prices are a bit more comparable to oil prices and, for this reason, it would be logical for these revenues to be treated as oil revenue, as is the practice in many countries. In contrast to this logic, Kellas (2010) also points out that treating condensate as gas revenue and applying lower tax rates can significantly increase the economic viability of a gas project. Brulpadda and Luiperd contain gas condensate, but a lot of our estimated reserves are yet to be proven at this stage.

A further important point made by Kellas (2010) is the complexity of applying graduated rates when oil and gas are produced together as costs need to be allocated to different revenue streams. Many of the costs – including operating and maintenance will be common to both operations and difficult to separate. It is not surprising that Kellas (2010) advocates instead for a tax instrument that is linked to project profitability as a progressive instrument will overcome all these challenges. If oil is more profitable relative to gas, then it will be in a better position to contribute more to the fiscus.

For these reasons, it is not deemed necessary to separate oil and gas for the purposes of a royalty calculation as it would lead to complexity for investors and SARS. With respect to the suggestion for a progressive tax instrument, the royalty does not necessarily need to satisfy that criterion given the mix of fiscal instruments applying to this sector. In terms of the proposed 20 per cent carried interest, the State will receive revenue after its share of costs have been paid to the investor. The corporate income tax is only applied to profits, which are reduced by the ability to deduct more than what is spent on capital throughout the project. If royalties for oil and gas are also based on profitability (as they currently are), all three of the main fiscal instruments applying to this sector would be based on profit. The implication is that Government will have little ability to generate any income from the start of production, besides 0,5 per cent applied to gross sales, which is low in comparison to other countries.

The economic modelling exercise tested a number of tax regime changes in addition to the State's 20 per cent carried interest, which will increase Government's share of revenue compared to the current MPRDA. Incorporating all potential changes is important as no one policy change can be evaluated in isolation. With respect to royalties, two variations to the current regime were included. One retained the current royalty design, but the range of rates was changed from 0,5 to 5 per cent to 2 to 10 per cent. This option retains the flexibility of the current regime, but its design has been identified as unnecessarily complex. The second option imposed a flat royalty of 5 per cent. The IMF's modelling exercise showed that the current maximum royalty rate of 5 per cent would be reached quickly in all viable projects. The National Treasury modeling exercise used more conservative numbers with respect to field size and costs, but the overall view based on NPVs emerging from different field size, costs and oil price combinations suggests that applying a flat rate of 5 per cent to gross sales would be suitable.

Relative to the current regime, it would increase royalty revenue from the start of production, but the capital uplifts would still delay the reporting of profits used to calculate corporate income tax. A flat-rate royalty would enable the state to benefit as soon as production starts – an important compensatory mechanism for the loss of finite resources.

b. Capital allowances

The Tenth Schedule to the ITA has generous capital allowances. For any capital expenditure incurred in respect of exploration[65] activities, an investor can immediately expense the cost, plus deduct a further 100 per cent of that cost in the year of expense. Capital expenditure in relation to post-exploration[66] activities, can also be fully expensed in the year incurred with an uplift of 50 per cent of that cost. This has the effect that R100 spent in respect of exploration activities allows the investor to deduct R200, while R100 spent in respect of post-exploration activities yields a R150 deduction.

It is fully recognised that a country without substantial certainty regarding the extent of its oil and gas resources cannot impose a stringent fiscal regime as no investment would take place. Currently, exploration activity and the encouragement thereof is important, but it is crucial that this is done within the context of South Africa's commitments to reducing carbon emissions. The IMF report showed that the current regime – even though designed for an industry that is not yet developed – is on the generous side relative to other countries. The international review confirms its generosity, although it is difficult to benchmark against the almost 29 countries which use PSCs. Furthermore, moves toward sustainable finance render the possibility of stranded assets in this industry a reality. The current allowances would mean that government is subsidising investment in assets that may become stranded in future, which combined with indefinite carry-forward allowances, poses a risk in terms of lost tax revenue when production starts.

The existing allowances may be too generous in that they do not provide sufficient incentives for oil and gas companies to reduce capital expenditure, which, as a result, can incentivise an increase in capital expenditure or "front-loading" capital expenditure so as to retain the capital allowance. "Front-ending" of capital expenditure (i.e. skewed towards the initial phases) has the effect of reducing government take.

Given the move in the UPRD Bill to incorporate exploration and production rights into one petroleum right, as well as the IMF's comments on challenges raised by (i) basing capex uplifts on the type of right (phase of the project) rather than on activities, and (ii) the potential for abusing the fact that exploration capex attracts a higher uplift, it appears preferable to move towards removing the uplifts entirely and rather allowing immediate expensing for all capex in this industry. This would be more in line with the countries that provide more generous tax treatment of capital expenditure in this industry – i.e. immediate expensing as opposed to writing off over a number of years.

However, many countries provide preferential write-off treatment for exploration so there is precedent for different treatment. Secondly, government would still like to encourage further exploration while being mindful of its commitments to reducing carbon emissions – particularly in respect of coal. With the State gaining a 20 per cent share in production/revenue, the modelling suggests that removing the uplifts can turn NPVs negative with the estimated reserves and oil price ranging from 40 to 80 USD if the high-cost assumption is used. If the lower-cost assumption is used, projects can still be viable if

[65] "exploration" means the acquisition, processing and analysis of geological and geophysical data or the undertaking of activities in verifying the presence or absence of hydrocarbons (up to and including the appraisal phase) conducted for the purpose of determining whether a reservoir is economically feasible to develop;

[66] "post-exploration" means any activity carried out after the completion of the appraisal phase, including— (a) the separation of oil and gas condensates; (b) the drying of gas; and (c) the removal of non-hydrocarbon constituents, to the extent that these processes are preliminary to refining.

uplifts are removed at an oil price of just below USD 60. However, combining a flat-rate royalty with a removal of the uplifts means that projects become unviable according to the modelling conducted.

c. Petroleum Resource Rent Tax

The possibility of a resource rent tax was discussed in a National Treasury mining tax discussion paper in 2013[67]. While this is seen as the best way of instilling neutrality and efficiency into resource tax design (in that it is not viewed as affecting investment decisions), it does suffer from important drawbacks. It is notoriously difficult to establish what a normal rate of return is for any project – as typically a resource rent tax (RRT) is applied on what is termed excess returns (beyond a so-called "normal" rate of return). Many countries have used long-term government bond rates as a proxy for normal returns. Still, using a measure like the internal rate of return of a project as a threshold (for example – as Angola does) to distinguish between normal and excess returns would bring up many administrative challenges for SARS. These challenges would be akin to well-known challenges in the transfer pricing space – with SARS having to audit whether or not terms and conditions are at arm's length.

One option considered is a design similar to the Australian PRRT – which is essentially a cash flow surcharge. It kicks in once a project turns cash flow positive (i.e. all capital expenditure has been fully redeemed with an uplift, with no offsets against receipts for finance costs). The IMF suggested this for South Africa at a rate of 20 per cent as an alternative to state equity. An instrument like this would be less complex than a pure economic resource rent tax and would ensure that government is able to benefit from surges in oil and gas prices. Importantly, the IMF recommendation was meant as a substitute for state equity, so having both would not be viable.

On top of the traditional design challenges of a resource rent tax, it is critical that all stakeholders understand that a resource rent tax or cash flow surcharge will not generate any revenue for government during the exploration and development phases and that it will only yield revenue in the production phase years once the investor has recovered its capital expenditure.

The proposal for a carried interest of 20 per cent in each petroleum right for the state is similar in design to what the IMF proposed and what is in place in Australia. Investors can recover 50 per cent of the state's share of exploration costs and 100 per cent of production costs. The state must reimburse the investor from its proceeds before benefitting from its revenue share.

d. Withholding taxes

While withholding taxes on royalties will apply to investors at 15 per cent (subject to reduced treaty rates), withholding taxes on both dividends and interest are reduced to zero in the Tenth Schedule. The modelling exercise introduced a dividend withholding tax of 5 per cent to recognise that, without the Tenth Schedule carve-out, treaties can reduce the rate to as low as 5 per cent.

Government could pursue one of three options: (i) retain the status quo with WHT rates reduced to zero; (ii) reduce withholding taxes on dividends and interest to 5 per cent instead of zero – recognizing that many treaties will lower the standard rate to as low as 5 per cent anyway; or (iii) remove the special carve out in the Tenth Schedule so that the rate applied depends on whether a treaty applies or not.

Given the proposal with respect to the royalty regime, it is not considered necessary to change the

[67] Available: https://static.pmg.org.za/131106mining.pdf

status quo with respect to withholding taxes.

8.5 Proposal for overall package

The state's participation in net revenue / production combined with a flat-rate royalty would assist in balancing the government and investor take. A royalty at a reasonable rate would allow government to have a stable revenue source as soon as production starts. The carried interest means that the State will only start receiving its share of production / revenue after production commences once it has reimbursed the investor its share of costs. Although volatility in commodity prices can impinge on revenue stability, a flat-rate royalty would still offer more stability than a resource rent tax, for example. A flat-rate royalty also has the benefit of simplicity. A flat-rate royalty would be a nice complement to the State's carried interest and corporate income tax, which both generate revenue once the project is profitable.

Based on the international overview; tax policy design principles; the economic modelling exercise; South Africa's carbon emissions reduction commitments; and the discussion on each of the tax instruments above, Government seeks public comments on the following:

- a flat-rate royalty of 5 per cent on gross sales (as defined in section 6 of the MPRRA, 2008) for oil and gas companies (rather than a rate determined by the formula in section 4 of the MPRRA, 2008);
- no changes to the capital allowances applicable to oil and gas companies;
- no petroleum resource rent tax;
- no changes to the withholding taxes applicable to oil and gas companies; and
- the State's 20 per cent share of production / revenue must be channeled to the National Revenue Fund for the benefit of all South Africans. National Treasury and the DMRE will continue to discuss the financial and institutional arrangements for the National Petroleum Company.

Based on the analysis, it is not deemed appropriate at this stage to alter the generosity of the uplifts or the reduced WHT rates. Trying to increase the tax take by any other means would reduce the viability of upstream petroleum exploration in South Africa. The State's carried interest in combination with a flat-rate royalty will enhance the government's take relative to current legislation.

With this proposal, Government is seeking to balance the need to invest in less-carbon intensive transition fuels with providing a fiscal and tax regime that is attractive enough for companies to explore for and produce oil and gas, but at the same time avoids incentivising assets that could be stranded due to stricter climate commitments and environmental regulations. As stated, South Africa is in the process of determining further measures to achieve its NDCs, including to what extent gas could act as a transitional fuel and energy source in relation to coal. While gas is a fossil fuel, its emissions are around 50 per cent less than coal and could act as an important transition fuel as the economy transforms and shifts to lower-carbon, renewable and energy efficient technologies. This would also help to facilitate a just transition to a lower-carbon economy and ensure energy security of supply and affordable energy that is accessible by all.

Government is also interested in receiving comments in respect of all other content in this document

– including in respect of how climate change will impact this industry and how the tax system should treat fossil fuel investments.

8.6 Stability agreements

Fiscal stability agreements are currently provided for in the Tenth Schedule to Income Tax Act and the MPRRA. Investing in exploration, development and production of oil and gas resources is an expensive exercise with long time horizons. From this perspective, it is understandable that investors want certainty in this regard. Not all countries provide FSAs, however doing so is often dependent on proven reserves and perceived political risk.

Government has considered the practices of other countries and has reviewed the IMF and DTC recommendations. The IMF report[68] sums up the balancing act well:

"*The high levels of investment and long-term nature of the EI make fiscal stability a particular issue when deciding to invest or not. This reasonable need has to be balanced against the dynamic and changing nature of fiscal regimes generally, administrative issues and the often incomplete and asymmetric nature of information with respect to natural resources. <u>While potential investors are concerned about major shifts in imposts during the life of a project, they are often less concerned about incremental shifts in generally applicable tax rules. Investors are particularly concerned about changes that target or discriminate against a particular industry or activity</u>*."

For the past 7 years, Government has not approved any fiscal stability agreements. The following statement was made in Chapter 4 of the 2019 Budget Review under the heading – *Review of tax treatment of oil and gas activities:*

> *"Taxation of the oil and gas is currently governed by the tenth schedule to the Income Tax Act., which makes provision for the Minister of Finance to approve a fiscal stability agreement to any qualifying company. A fiscal stability agreement guarantees that both the headline rates of tax and the rules behind the calculation of tax liabilities will continue to apply for the duration of a company's oil and gas right. Government has not approved any fiscal stability agreements in the past five years. South Africa will review its oil and gas regimes in 2019."*

Government would like to receive public comments on the following policy matters:

A. Given that Government has not signed any FSAs in the past 7 years, and in light of previous Budget announcements that Government intends to review all incentives to broaden the tax base and lower the corporate tax rate, should Government continue with the provisions of paragraph 8 of the Tenth Schedule (which enables the Minister of Finance to enter into an FSA)?

B. Should Government continue to provide for FSAs, please share your thinking on the following:

    a. In what form and manner should FSAs be granted?

    b. What type of taxes should be covered by the FSA and why?

[68] IMF (2015), South Africa: Technical Assistance Report—Fiscal Regimes for Mining and Petroleum: Opportunities and Challenges

c. Should FSAs cover taxes payable by the oil and gas company only, or should they be extended to cover taxes paid by shareholders and providers of finance to the oil and gas company, and why is that so?

d. A corporate tax package – consisting of a rate reduction from 28 to 27 per cent coupled with two base broadening measures (restricting assessed losses and strengthening the interest limitation rules) – was included in the 2021 Budget. Should FSAs apply to all elements of the above-mentioned package or any other potential corporate tax proposals in the future?

e. Considering South Africa's commitments in respect of climate change as an example, should signed FSAs, as contemplated in paragraph 8, should have a limited lifespan (e.g. 10 years) to allow all relevant stakeholders to either re-assess or re-negotiate their positions due to changing variables during the long-term nature of the oil and gas industry?

f. Do FSAs, as currently contemplated in paragraph 8, fairly represent worldwide practice?

C. If Government does not continue with the provision for FSAs, will that hinder companies from exploring and developing oil and gas reserves?

D. Are there any other issues that you would like to highlight in respect of FSAs?

8.7 Additional payments / fees in respect of the UPRD Bill

As per the UPRD Bill, investors will be liable for application fees, exploration fees and administration fees payable to the Petroleum Agency SA. Furthermore, upstream oil and gas companies are required to pay contributions to the Upstream Training Trust – established in 1997 to address the shortage of skills in the upstream industry by encouraging learners to study mathematics and science at school and register for tertiary studies that would support this growing industry.

8.8 Sovereign wealth fund

This section on sovereign wealth funds (SWFs) is not intended to determine whether an SWF is required or to ascribe any design or function of an SWF, rather it is an overview. Discussions about an SWF will be considered separately by the National Treasury.

SWFs are dedicated investment vehicles, owned by a sovereign government, managed independently of other state financial and political institutions and invest in a diverse set of financial asset classes.[69] They are essentially savings pools for the State. There are generally two broad classes of SWFs – (i) macroeconomic stabilisation with a primary focus on rules that divert and return revenues to support counter-cyclicality (shorter term, analogous to rainy day savings accounts), and (ii) investment returns

[69] "SWFs are defined as special purpose investment funds or arrangements, owned by the general government. Created by the general government for macroeconomic purposes, SWFs hold, manage, or administer assets to achieve financial objectives, and employ a set of investment strategies which include investing in foreign financial assets. The SWFs are commonly established out of balance of payments surpluses, official foreign currency operations, the proceeds of privatizations, fiscal surpluses, and/or receipts resulting from commodity exports." International Forum of Sovereign Wealth Funds.

that seek to diversify and raise the country's wealth (longer-term, analogous to personal pension fund saving).

There are important ingredients for successful SWFs. The most important issue is a clear understanding of the costs and benefits of building up fiscal savings, and how those savings should best be deployed. A SWF also needs to be politically and economically realistic (short-term fiscal pressures seem to result in pressure to rely on these savings in tough times). Such a fund would need to be integrated into the fiscal framework if it hopes to succeed (very clear fiscal rules for managing spending and / or revenue saving. Institutions and a legal framework to prevent dipping into the SWF to finance ad hoc or volatile expenditures).

SWFs often come into existence when a particular revenue stream is discovered, for example gas. In the context of finite, non-renewable resources like oil and gas, as well as considering that intergenerational equity is an important component of South Africa's fiscal strategy, it would be prudent to consider this form of fund for potential new revenue streams from oil and gas.

This decision will need to be taken in the midst of a difficult economic climate where we are currently experiencing a pandemic and the current fiscal position means that it may be difficult to make the case to create a "savings fund" when funds are urgently needed for public service delivery.

Should a SWF be considered, the National Treasury must have oversight over the fund to ensure that it is integrated into the fiscal framework. Management of funds depends on the nature of investments being undertaken. Strict governance arrangements need to be in place. There are voluntary general investment principles adhered to under the International Forum of Sovereign Wealth Funds.

The document aims to invite discussion among key stakeholders in respect of the proposals; impact of climate change on this industry; how best should the tax system treat future fossil fuel investments; and questions posed relating to fiscal stability agreements. Please send any comments to hayley.reynolds@treasury.gov.za and 2022AnnexCProp@treasury.gov.za by **25 January 2022**. These comments may be made public. Please clearly indicate in your submission if you prefer your comments to remain confidential. A public workshop will be held to which all commentators will be invited.

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Annexure A

Section 24 of the Constitution establishes the right to an environment that is not harmful to one's health and wellbeing and to have the environment protected, for the benefit of present and future generations through reasonable legislative and other measures that prevent pollution and ecological degradation; promote conservation; and secure ecologically sustainable development and use of natural resources while promoting justifiable economic and social development. [70] The National Environmental Management Act (NEMA), No. 107 of 1998 applies the constitutional rights in a practical environmental context which serves as the framework within which environmental management and implementation plans are to be formulated, and serve as guidelines for any state organ exercising any function concerning the protection of the environment.[71] The NEMA provides for cooperative environmental governance by establishing principles for decision-making on matters affecting the environment; institutions that will promote cooperative governance and procedures for coordinating environmental functions exercised by organs of state.[72] Specifically, Section 2 of The NEMA details a framework for decision making all organs of state need to apply including the environmental management principles in Section 2(1) and Sections 2(2) to 2(4) stipulate principles applicable to every person that does something that may harmfully impact on the environment. Thus any legislation governing the oil and gas industry must give effect to the above-mentioned NEMA guideline principles which include polluter-pays-principle, prioritise the public interest, public participation, contribute to sustainable development, risk-averse and cautious approach, preventing or minimising negative environmental impacts such as ecosystem disturbances or loss of biological diversity, environmental pollution and degradation, regulation from "cradle to grave" to ensure effective compliance at any stage and securing adequate financial provision.[73]

Taking into account government efforts to implement the "One Environmental System" where all environmental matters pertaining to mining are to be regulated in terms of the environmental legislation, as of November 2015, the Financial Provisioning Draft Regulations were published in terms of the NEMA.[74] The purpose of these Regulations are to ensure financial provision for costs associated with the remediation and rehabilitation of negative environmental impacts associated with mining activities including reconnaissance, prospecting, exploration, mining or production operations. The Regulations are however implemented by the Minister of Mineral Resources and Energy who is required to regulate applicants and holders of different types of mining rights, permits and ensure that rehabilitation of negative environmental impacts from the above-mentioned activities are provided for and carried out.[75] However, it should be noted that the final Financial Provisioning Regulations were gazetted on 27 August 2021 and provide that existing rights and permit holders (i.e. those who applied

[70] Constitution of the Republic of South Africa. Available on https://www.gov.za/documents/constitution/chapter-2-bill-rights#24

[71] Centre for Environmental Rights: Minimum requirements for the regulation of environmental impacts of hydraulic fracturing in South Africa, a position statement, February 2014. Available on: https://cer.org.za/wp-content/uploads/2014/04/CER-Minimum-Requirements-for-the-Regulation-of-the-Environmental-Impacts-of-Fracking-Web.pdf

[72] NEMA Act. Available https://www.gov.za/sites/default/files/gcis_document/201409/a107-98.pdf

[73] Centre for Environmental Rights: Minimum requirements for the regulation of environmental impacts of hydraulic fracturing in South Africa, a position statement, February 2014. Available on: https://cer.org.za/wp-content/uploads/2014/04/CER-Minimum-Requirements-for-the-Regulation-of-the-Environmental-Impacts-of-Fracking-Web.pdf

[74] https://www.gov.za/speeches/minister-environmental-affairs-publishes-amendments-financial-provisioning-regulations

[75] Ibid

for offshore oil and gas exploration and production rights prior to 20 November 2015) will now have to comply with these provisions by 19 February 2024, but new entrants into the market have to comply with the regulations since their enactment on 20 November 2015.[76]

Given the requirement for companies to make financial provision for the rehabilitation and management of potential negative environmental impacts and that exploration and production activities cannot commence without environmental authorisation granted in terms of the NEMA, prior to the granting of which an environmental impact assessment investigating the potential impact of the proposed activity must be conducted. Upon the lapsing, abandonment or cancellation of the right, cessation of exploration or production operations, or in respect of any relinquished portion, The Minister of Mineral Resources and Energy issues the closure certificate but may retain such portion of the financial provision as may be required to rehabilitate the closed production or exploration operation in respect of latent, residual or any other environmental impacts, including the pumping of polluted or extraneous water, for a prescribed period.[77] It is therefore recommended that the fiscal regime for the oil and gas sector should take into account these financial costs incurred by the industry. In terms of the NEMA, right holders are required to apply for a closure certificate.

[76] https://www.lexology.com/library/detail.aspx?g=a37e5d00-4e14-4a21-aebe-8ccb3174d196

[77] Oil & Gas Regulation 2018 – The International Comparative Legal Guide to: A practical cross-border insight into oil and gas regulation: 13th Edition Available on: https://www.bowmanslaw.com/wp-content/uploads/2018/02/OG18_Chapter-24-South-Africa.pdf

Annexure B

1. Davis Tax Committee recommendations

The Davis Tax Committee (DTC) was established by the Minister of Finance in 2013 to assess the country's tax policy framework and its role in supporting the objectives of inclusive growth, employment, development and fiscal sustainability. The committee's Oil and Gas Report focused on reviewing the existing tax regime applicable to oil and natural gas production in South Africa. The DTC noted that the current fiscal regime for oil and gas is well-established and efficient, and major changes were not required given that the primary deterrents to investment in South Africa appeared to be due to factors outside the tax system. The committee noted a number of potential areas for refinement under the Tenth Schedule to the Income Tax Act (ITA) and made the following proposals:

- Fiscal stability agreements should be concluded for the 'first-mover' companies. These companies face high geological and commercial risks because South Africa's oil and gas industry is still at the early stages of development and uncertainty remains in terms of its size and the commercial recoverability of oil and gas reserves.

- Preserve fiscal stability by ensuring that the entire ITA is covered under the signed fiscal stability agreement. Any new tax dispensation should apply prospectively to all new rights issued, including the acreage that is released through the relinquishment process once the extent of commercially viable resources can be more accurately scoped.

- Allow for the transferability of fiscal stability rights upon the disposal of a production right to any other oil and gas company. The Tenth Schedule limits the transfer of fiscal stability agreement rights to instances where an oil and gas company disposes of an exploration right and the production right is transferred within the "same group of companies". This has the potential of creating an uneven playing field and discouraging new entrants.

- The definition of oil and gas company in the ITA should be extended to include historically disadvantaged right holders. The current definition of 'oil and gas company' in the Tenth Schedule excludes oil and gas rights holders that are not incorporated in the legal form of a company.

- Allow for the tax-free transfer of funding held in a rehabilitation trust or rehabilitation company to the financial vehicles recognised in the National Environmental Management Act (NEMA) regulations. Currently, the transfer of funding in a rehabilitation trust or rehabilitation company to the financial vehicles recognised in the NEMA regulations attracts corporate tax and penalty from SARS. Thus, making it prohibitive for oil and gas companies to satisfy the immediate NEMA financial provision for the rehabilitation, management and closure of environmental impacts.

- Replace the variable royalty rate formula with a flat rate royalty rate of 5 per cent for oil and gas. The current royalty formula applicable to the rest of the mining industry is designed to increase the rate of taxation marginally depending on the profitability of the mine. In the case of oil and gas the IMF simulation results show that once an oil and gas company enters production it will almost immediately begin paying royalties at the maximum rate and continues at this royalty rate for the significant portion of the life of the field.

- Retain the 10 per cent assessed loss set-off provision to encourage local beneficiation of South Africa's oil and gas petroleum resources through the refining of indigenous condensate and gas. This would imply that imported condensate (and crudes), imported LNG feedstock and imported blend-stocks (used to achieve the liquid fuels specifications in terms of octane requirements) to the refinery would not qualify for the offset of tax losses from exploration and production expenditure in relation to an MPRDA right.

- Retain the zero per cent withholding tax on dividends as it is consistent with a tax system aimed at equitable treatment of resident and non-resident oil and gas companies. Further, the introduction of a dividends withholding tax in the absence of branch profits remittance tax may result in avoidance schemes utilizing branch holding structures.

- Does not recommend an amortization write-off in respect of the various mineral rights accorded in terms of the MPRDA. This is in line with international practice and the current regime allows for a deduction in relation to the consideration paid for an oil and gas right in the form of the participation election at paragraph 8 of the Tenth Schedule.

- SARS should issue an interpretation note to provide further clarity on the classification of "capital expenditure" for purposes of the Tenth Schedule. Section 36(11) of the ITA provides a definition of 'capital expenditure' for hard rock mining purposes. What is, and what is not, 'of a capital nature' is not defined in the ITA for Tenth Schedule purposes and depends on a complex body of case law.

2. IMF recommendations

The Davis Tax Committee commissioned the Fiscal Affairs Department of the IMF to prepare a report on the South African mining and petroleum fiscal regimes. In 2015, the IMF issued report, Fiscal Regimes for Mining and Petroleum: Opportunities and Challenges, which was supplemented with additional analysis in 2016. IMF reports make the following observations and recommendations:

- Warns that the application of the current mining provisions to oil and gas may have unintended consequences and possible abuse. This is particularly true where the ring-fence for a particular expense is broader or narrower under the mining provision than under a Tenth Schedule provision. For example, mining provisions make no reference to "natural oil" or "oil and gas", which means they could also apply for oil and gas companies in respect of items like trading stock under section 15A. In addition, because the taxable income of an oil and gas company is not defined in the Tenth Schedule, such companies may circumvent ring-fencing by deducting expenses under the general deduction provision instead of the Tenth Schedule.

- There is a need to bring together current fragmented rules that deal with extractive industries. There should be a separation in terms of the rules that apply to mining and those applying to oil and gas. Current special rules should be reviewed and new rules need to be based on consistent and coherent policy.

- Do away with the different treatment of 'exploration' and 'post-exploration' expenditure as this may have distorting effects. The Tenth Schedule allows for a 100 per cent uplift in the deduction of 'exploration' capital expenditure, and a 50 per cent uplift in the deduction of 'post-exploration' capital expenditure. Whether an activity qualifies for the 100 per cent uplift depends on the type of activity conducted instead of the type of MRPDA right being held. This has the unintended consequence of exploration right holders possibly benefiting from the 100 per cent uplift for post-exploration expenditure. To address this anomaly, a five-year write off period is recommended, which is in line with international practice.

- Tax treatment of acquisition costs of a petroleum right needs to be reviewed. The IMF proposes that amortization of acquisition costs should be allowed and rollover and participation elections need to be revised with appropriate safeguards.

- Limit deduction of 10 per cent of assessed losses against non-oil and gas income to actual expenditures, i.e. not including uplifts.

- Government should allow fiscal stability for the 'first-mover' companies, and deal with the transition to any new tax dispensation by enforcing the relinquishment provisions under the MPRDA, which compel the size of a block/field to shrink as the oil and gas project moves thorough the life stages (for example, the conversion of an exploration right into a production right).

- Convert the variable rate into a flat rate royalty of around 5 per cent of gross sales at the point of actual sale or first saleable point. A flat royalty would make the determination of the royalty simple and easier for both revenue authority and taxpayer to administer, in the context of petroleum resources.

- Recommends three options to deal with the uncertainty of state participation*: (i) Delete the state participation provisions altogether; (ii) comprehensive shift to a production sharing contract (PSC); or (iii) define the state participation option precisely and publish a model participation agreement that the companies with exploration rights could sign.* Option one was the preferred option alternatively option one together with option three if non-fiscal considerations favour state participation.

- An alternative to state participation could be the introduction of a cash flow surcharge. The cash flow surcharge of 20 per cent becomes payable on taxable income, net of royalties, when the oil and gas company has redeemed the full amount of its capital expenditure, with a once off 10 per cent uplift. The IMF arrived at this alternative by evaluating the current regime and 3 alternative scenarios. The alternative regimes were evaluated against the key fiscal objectives of revenue-raising capacity, neutrality and progressivity, and compared to other petroleum-producing countries. Scenarios 1 and 3 include a 5 per cent flat rate royalty and 5-year depreciation using the straight-line method along with a 10 per cent allowance for corporate capital (disallowing deductibility of interest). Scenario 1 (a) and (b) add an additional cash flow surcharge at 20 and 30 per cent respectively, with ten per cent uplift on capital expenditure in the year that it is incurred. Under scenario 3, a 20 per cent state participation, carried from development and repaid with interest, and an R-Factor based production sharing scenario is introduced.

Annexure C

Table 9: Countries with royalties

Country	Type of contract	Petroleum Income Tax	Royalty	Royalty base	Fiscal stability
Australia	C	30%	10-12.5%	Gross or net wellhead value of all the petroleum produced	
Canada	C	25%	45%	Well productivity and wellhead price	
Colombia	C	33%	8-25%; 60-80% gas expl.	Monthly average barrels of crude per day	
Germany	C	29.8%	0-40%	Market value of the produced oil or gas	
Greece	C	20%	R-factor	R-factor	
Greenland	C	30%	Yes	Under the current regime, a special surplus royalty regime applies to all licenses. Special conditions may be found in the licenses.	
Italy	C	24%	7-10%	Gross value of oil and gas production	
Kazakhstan	C	20%	0.5-18%	The royalty tax is volume based	Yes
Kuwait	C	15-57%	15%	Royalties are considered in the same manner as normal business income and are subject to tax at 15%	
Lebanon	C	24%	Royalties on crude oil (5% - 12% depending on production levels) Royalties on natural gas (4% of production)	Royalties are imposed annually and can vary between 5% and 12% based on the production level per day for crude oil and 4% for natural gas.	
Morocco	C	10-31%	3.5-10%	Gross income	
Namibia	C	35%	5%	Value of production	
Netherlands	C	19-25%	0-7%[78]	Gross revenue	
New Zealand	C	28%	0-20%	Net sales revenue earned in a period	
Papua New Guinea	C	30%	2%	Cumulative available oil	Yes
Poland	C	19%	1.5-6%	The taxable base is the value of the extracted natural gas and oil.	
Romania	C	16%	3.5-13%		
Saudi Arabia	C	20-85%	On-contract	Extracted natural resource	
Singapore	C	17%	-	Value of the hydrocarbons produced	
South Africa	C	28%	0.5%-7%	Gross sales	Yes
Spain	C	30%	1-8%	The value of oil, gas and condensates being extracted within the territory of Spain	
United Arab Emirates	C	case-by-case	case-by-case	Value of produced hydrocarbons	

[78] Royalties are only due on onshore production licenses, as the applicable rate for offshore licenses is set at 0%.

United Kingdom	C	19-30%			
United States of America	C	21%	12.5-30%	Gross wellhead value	
Uruguay	C	25%	No	Gross wellhead value	
Venezuela	C	50%	20-33.3%		
Algeria	PSC	38%	5-20%	Royalties are due on the gross income and are paid by the NOC	
Benin	PSC	50-55%	10-12.5%	Wellhead value of the hydrocarbons	
China	PSC	25%	0-12.5%	Annual gross output	
Croatia	PSC	12-18%	10%	R-factor	
Equatorial Guinea	PSC	35%	On-contract	Total disposable production volume from a development and production area.	Yes
Ghana	PSC	35%	3-12.5%	Gross crude oil production	Yes
Guinea	PSC	35%	10%	Gross production	
India	PSC	31.2-43.68%	10-12.5%		
Madagascar	PSC			Cumulative velue of production	
Mauritania	PSC	25%	10%	Gross production	Yes
Myanmar	PSC	25%	12.5%	Wellhead value of oil and gas	
South Sudan	PSC	10-25%			
Sri Lanka	PSC	28%	1-10%	Value of mineral extracted	
Tanzania	PSC	25-30%	7.5-12.5%		
Uganda	PSC	30%		R-factor	
Vietnam	PSC	32-50%	1-29%	Value of extracted mineral	
Argentina	Hybrid 1	30%	12%	Wellhead value of the product	
Brazil	Hybrid 1	34%	5-10%	Concession- Oil and gas production reference price PSC- Volume of produced oil.	
Cameroon	Hybrid 1	33-50%	On-contract	Total monthly production available of a defined area.	Yes
Chad	Hybrid 1	40%	5-16.5%	Total production	Yes
Kenya	Hybrid 1	30%		Volume natural resource produced	Yes
Libya	Hybrid 1	65%	17%	Daily production level	
Mozambique	Hybrid 1	32%	6-10%	An oil (including natural gas) production tax (equivalent to a royalty) is due on the value of the oil (gas) produced in Mozambique at the development and production site	Yes
Nigeria	Hybrid 1	65.75-85%	0-20%	Net sales revenue	
Pakistan	Hybrid 1	40%	13%	Value of the extracted petroleum at the field gate	
Qatar	Hybrid 1	35%	On-contract	Value of the extracted natural gas and oil	
Russia	Hybrid 1	20%	US$0.6-US$15.3		
Senegal	Hybrid 1	30%	6-10%	Value of the hydrocarbons produced and not used in the petroleum operations.	

Syria	Hybrid 1	10-28%	7%	Average daily production rates (in million barrels of oil equivalent)	
Trinidad and Tobago	Hybrid 1	50%	12.5%	Value of petroleum sold	
Tunisia	Hybrid 1	50-75%	2-15%	Net volume of crude oil and natural gas won and saved at the fair market value	
Ukraine	Hybrid 1	18%	16%-70%	Royalties on hydrocarbons are calculated as a percentage of the value of produced hydrocarbons	
Uzbekistan	Hybrid 1	12%	2.6-30%		
Angola	Hybrid 2	50-65.75%	20%	Gross production	Yes
Gabon	Hybrid 2	35-73%	6-12%	Daily average of the total production	Yes
Mexico	Hybrid 2	30%	5-15%	Total daily production	Yes
Republic of the Congo	Hybrid 2	30%	On-contract	Royalties are calculated on net oil production.	
Thailand	Hybrid 2	50%	5-15%	Total crude oil/natural gas production	
Côte d'Ivoire	Hybrid 3	25%	5-20%	Daily oil production	Yes
Democratic Republic of Congo	Hybrid 3	No	8-12.5%	Net oil production	
Ecuador	Hybrid 3	25%	12.5% - 18.5%	Gross monthly income	Yes
Iraq	Hybrid 3	15-40%	10%	Daily quantity of petroleum produced	
Malaysia	Hybrid 3	38%	10%	Gross production	
Peru	Hybrid 4	31.5%	5-20%	Percentage of wellhead value	Yes

Source: EY Global oil and gas tax guide (2019)

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for Public Comment

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