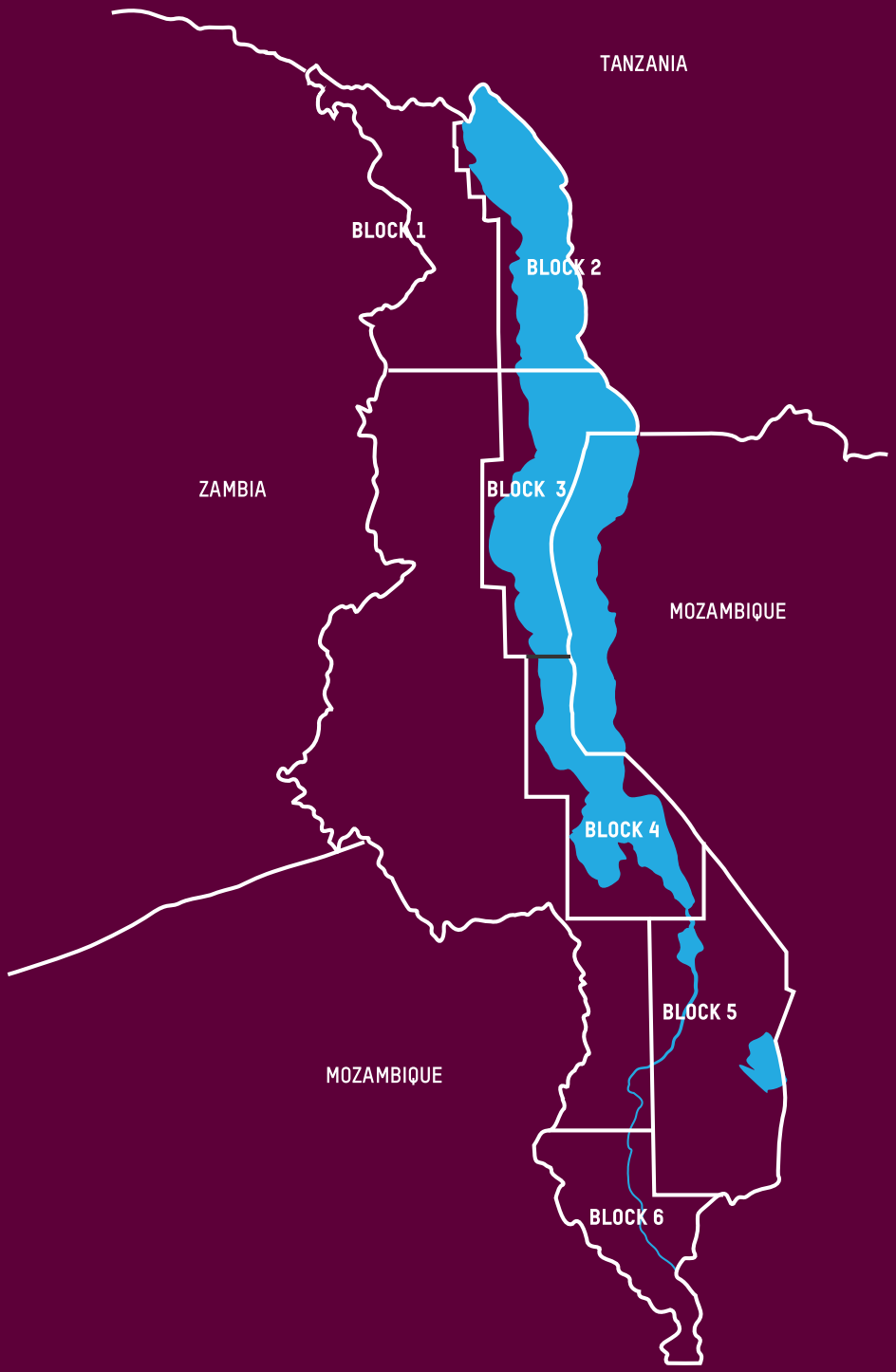
AN ANALYSIS OF FISCAL TERMS IN MALAWIAN OIL CONTRACTS THE IMPLICATIONS FOR POTENTIAL GOVERNMENT REVENUE



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ACKNOWLEDGEMENTS

This report would not have been possible without the unfailing support of the Oxfam Team in Malawi (Country Director John Makina, Program Manager Lusungu Dzinkambani and Extractives Industry (EI) Coordinator Elyvin Nkhonjera Chawinga) and internationally (Southern Africa Regional Advisor on EI Titus Gwemende and EI Oxfam America Program Manager Maria Lya Ramos). We also appreciate the input received during consultations undertaken in Lilongwe on 14-16 February 2018 with Malawi Extractive Industries Transparency Initiative, the Revenue Policy Division of the Ministry of Finance, the Department of Mines and Geological Survey, and the Chamber of Mines.

ABOUT RESEARCHERS

Don Hubert is President of Resources for Development Consulting. His work focuses on using contract analysis and project economic modeling to strengthen extractive sector governance. He has conducted economic analyses of extractive sector projects in Angola, Belize, Bolivia, Cambodia, Chad, Equatorial Guinea, Kenya, Malawi, Mozambique, Tanzania, Uganda and Zimbabwe. He worked for the Canadian Ministry of Foreign Affairs for ten years and as an associate professor of public and international affairs at the University of Ottawa for four years. He holds a PhD from the University of Cambridge.

Gordon Kirkwood has been Senior Associate with Resources for Development Consulting since 2014. Dr. Kirkwood worked in the oil and gas industry for BP for 30 years as a Petroleum Engineer, Economist and Business Advisor in countries including UK, Egypt, Venezuela and the United Arab Emirates. Dr. Kirkwood is a Chartered Engineer (Petroleum), a European Engineer and Fellow of the Institute of Materials, Minerals and Mining. He has provided technical support for Resources for Development petroleum projects in Angola, Belize, Cambodia, Equatorial Guinea, Kenya, Malawi, Mozambique, Tanzania and Uganda.

Lindsey Allwright has been an Associate with Resources for Development Consulting since 2013 and has prepared economic models for upstream petroleum projects in Belize, Cambodia, Kenya, Malawi, Mozambique, Tanzania and Uganda. She was previously an ODI Fellow in the Ministry of Planning and Development in the Government of Mozambique. She holds a Master's Degree in Development Economics from the School of Oriental and African Studies in London.

Fredrick Maliro is a Principal Revenue Officer for the Ministry of Finance, Economic Planning and Development in Malawi. He specializes in taxation and public policy, and energy and mining economics, including financial modeling. He supported the review of the mining fiscal regime in Malawi and has also been supporting the Government of Malawi in the analysis of financial models. He holds an MSc. in Energy Studies with Specialization in Energy Economics from Dundee University in Scotland.

TABLE OF CONTENTS

INTRODUCTION 1
Project Rationale and Methodology 1
Report Structure 2

FISCAL TERMS IN MALAWIAN OIL CONTRACTS 4
An Overview of the Main Fiscal Instruments 5
5 6
Comparing the Three Sets of Fiscal Terms 7
Secondary Fiscal Issues

OIL FIELD SCENARIOS 8
Large Onshore Field 8
Small Onshore Field 9
Large Offshore Field 9
Oil Price 10

COMPARISON OF FISCAL REGIMES AGAINST SCENARIOS 11
The Economics of Large Onshore Development 11
he Economics of Small Onshore Development 13
The Economics of Large Offshore Development 15

SUPPLEMENTARY ANALYSIS OF THE SIGNED PSAS 17
Production and R-factor Profit Oil Splits 17
A Negotiated Reduction in the Rate of Corporate Income Tax 18

REGIONAL BENCHMARKING 21
The Fiscal Regimes in Kenya and Uganda 21
Comparative Analysis 22

CONCLUSIONS AND RECOMMENDATIONS 21

Annex 1: Fiscal Regime Modeling Assumptions 24
Annex 2: Project Consultations 33

INTRODUCTION

Africa's Great Rift Valley holds exciting petroleum prospects. In Uganda and Kenya, around two billion barrels of proven reserves have been discovered. In Mozambique and Tanzania, stunning offshore natural gas finds hold the prospects for transforming those economies.

Malawi has sought to capitalize on the enthusiasm for petroleum exploration in the region. Prospecting licenses for the six Blocks that cover Malawi's potential oil-bearing areas were issued between 2011 and 2013.

The legal framework for Malawi's petroleum sector is dated. The Petroleum Act was first enacted in 1983 and is now under review. In the petroleum sector, it is common for a single contractual agreement to set the terms for the full project lifecycle. The contract covers the initial exploration phase and, assuming commercial discovery, continues through project development, oil production and eventual decommissioning.

In order to compensate for this legal shortcoming, the government sought to develop a state-of-the-art production sharing agreement (PSA) in order to establish the rights and obligations of private sector oil companies. A model production sharing agreement was prepared between 2010 and 2014. The draft model agreement, however, was never completed. The last incomplete step was calibrating the fiscal terms – the instruments that generate the government's share of revenues should oil production come on-stream.

IN LATE 2016, THE GOVERNMENT SOUGHT TO RENEGOTIATE THE FISCAL TERMS CONTAINED IN THE PSAS FOR BLOCK 4 AND 5 WITH RAKGAS

In May 2014, negotiations were completed for production-sharing agreements covering Blocks 4 (RAKGas), 5 (RAKGas) and 6 (Pacific). While the general structure of the contract remained the same, significant revisions were made to the core fiscal terms. In keeping with international best practice, the Government has disclosed these three contracts.[1]

The allocation of the licenses and the subsequent PSAs were the subject of a review by the Attorney General. Initial concerns appear to have been resolved, and the companies were informed they could proceed with exploration in late 2016.

In late 2016, the government sought to renegotiate the fiscal terms contained in the PSAs for Block 4 and 5 with RAKGas. These negotiations apparently resulted in the preparation of a proposed Addendum including significant revisions to the main fiscal terms. These proposed terms entered the public domain when an official from the Department of Mines, Ministry of Natural Resources, Energy and Mining listed them at a meeting of the MWEITI MSG on 13 February 2017. No additional confirmation of these terms, however, has been found.

To date, three different sets of fiscal terms have been considered for Malawi's nascent petroleum sector. This report seeks, for the first time, to provide a detailed comparative analysis of these terms, and of their implications on both government revenue and company economics.

Project Rationale and Methodology

Malawi benefited from considerable international assistance in the preparation of the draft model contract.[2] However, at that time, the proposed

fiscal regime had not yet been subjected to detailed economic modelling and analysis. There is no indication that the fiscal terms contained in the signed PSAs were subjected to economic modelling by government negotiators. Government capacity has been strengthened in the intervening years and some modelling of potential fiscal terms was undertaken in advance of the negotiation surrounding the proposed Addendum.

In an effort to promote evidence-based policy development with the Malawi Government, Oxfam engaged Resources for Development Consulting to undertake an economic analysis of the various fiscal terms that have been proposed for the oil sector in Malawi.

Oxfam Malawi previously published a report on Malawi's PSAs. That report documented the allocation of petroleum rights in Malawi including the Prospecting Licenses, the circumstances surrounding the signing of the PSAs for Blocks 4, 5 and 6, and a detailed description of the fiscal terms contained in the model PSA, the signed PSAs and the proposed Addendum. That analysis, however, did not analyse the implications for company economics and for government revenue flowing from the different fiscal term options.

This report builds on the previous effort by providing a detailed comparison of the three different sets of fiscal terms against plausible oil fields that could potentially be developed in Malawi.[3] At the core of this analysis is a discount cashflow model developed in Microsoft Excel. Cash flow modelling is the industry standard methodology for analysing investment opportunities. It can also be adapted to analyse potential revenues flowing to the government from extractive sector projects.

The project was carefully designed to engage the full range of relevant stakeholders and to strengthen their capacity. Specifically, the project sought to:

1. Secure input from Malawian stakeholders into the design and development of the model;
2. Contribute to further review of fiscal terms among government Ministries, and to strengthen capacity for future negotiations with oil companies;
3. Include a comparison of the economic implications for company and government of the fiscal terms that have been considered (signed PSAs, proposed Addendum and model PSA);
4. Be based on plausible scenarios for potential oil field production and export, including production and cost profiles prepared specifically for Malawi;
5. Include an Excel spreadsheet model allowing for the results of the analysis to be replicated, and for alternative fiscal regime options to be analysed;
6. Include regional benchmarking to assess how proposed Malawian terms compare to other "frontier" countries such as neighbouring Uganda and Kenya;
7. Contribute to greater transparency in Malawi's nascent petroleum sector in order to enhance awareness of the economic implications of the different fiscal regime options and to contribute to

THERE IS NO INDICATION THAT THE FISCAL TERMS CONTAINED IN THE SIGNED PSAS WERE SUBJECTED TO ECONOMIC MODELLING BY GOVERNMENT NEGOTIATORS

strengthened governance;
8. Provide capacity building for stakeholders on the workings of the petroleum industry, the value of petroleum economic analysis, as applied to the Malawian context.

Report Structure

The report begins with a review of the main fiscal instruments employed in Malawi's petroleum fiscal regime, and the specific terms associated with the signed PSAs, the proposed Addendum and the model PSA. The following section sets out the three oil field scenarios – large onshore, small onshore, and large offshore – including assumed recoverable reserves and estimated exploration, development, operating and transport costs. The third section contains the core economic analysis showing how the three sets of fiscal terms perform against the three different oil field scenarios. Two unusual provisions in the signed PSAs are then analysed: the combined production volume and R-factor profit oil split, and the government commitment to negotiate, in good faith, a reduction to the rate of corporate tax. The fourth section benchmarks the Malawi fiscal regime against oil contracts signed in Kenyan and Uganda prior to their respective oil discoveries. This is followed by the report's conclusions and recommendations.

FISCAL TERMS IN MALAWIAN OIL CONTRACTS

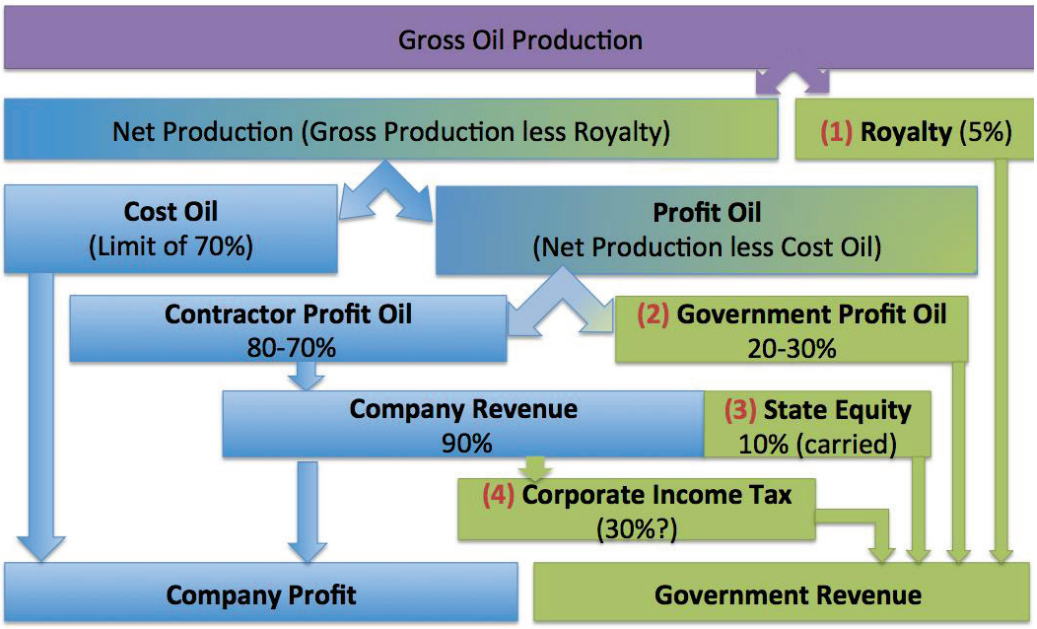
In setting out the fiscal terms that would determine the government's share of revenue from future oil projects, the Government of Malawi opted for the production sharing system. In its pure form, government revenue from a production sharing system is generated exclusively from a share of the oil produced. As is now common, Malawi chose to supplement its share of production with a royalty payment (as provided for under the Petroleum Act), a corporate income tax and an equity stake in the project.

In the Malawi production sharing fiscal system, there are four main sources of government revenue.

1. Royalty
2. Profit Oil
3. State Participation
4. Corporate Income Tax

The sequence for allocating potential revenue between the Malawian government and international oil companies, drawn from the signed PSAs for Blocks 4, 5 and 6, is set out in below.

Figure : Potential Revenue Allocation



The analysis contained in this report is based on the fiscal instruments contained in the signed PSAs, the proposed Addendum and the model PSA. It is important to note that while these fiscal instruments are commonly used in other jurisdictions, there are other approaches that could be adopted. Kenya, discussed below, initially opted for a pure production sharing system with no royalty or corporate income tax. Ghana, in contrast, opted for a variation on the royalty and tax system instead of the production sharing system. Securing a fair deal does not depend on the choice of fiscal system or on the number of fiscal instruments. There are many different ways to balance attracting the inward investment necessary to fund petroleum exploration and generating appropriate government revenues. The terms of reference for this

report focus on analysing the impact of the different sets of fiscal terms that have been considered in the past. As part of a wider review of Malawi's fiscal regime for the petroleum sector, consideration could be given to meeting core fiscal objectives with an alternative set of fiscal instruments that could be both appropriate to Malawi's specific circumstance and simpler to administer.

An Overview of the Main Fiscal Instruments

(1) Royalty

For most fiscal regimes, the payment of a royalty is the first step in the calculation of government revenue. As a result, it is often known as a payment "off the top." Royalties are a payment to the government calculated as a percentage of the value of production and are paid in full from the start of production.

(2) Profit Oil

The second source of government revenue in the Malawi fiscal system is a share of the oil produced. There are two steps in the allocation of oil produced: the recovery of costs by the contractor and the division of the remaining oil between the contractor and the government.

Cost Oil: Production sharing systems allow the contractor to recover its costs through an allocation of an initial amount of production termed "cost oil." Recovered costs include the exploration for oil, the development of the facilities to produce oil, and the operation of those facilities. In the first years of production, accumulated exploration and development costs normally exceed the value of total production. Many production sharing systems place a limit on the proportion of overall production that can be devoted to cost oil. This is done in order to ensure that at least some "profit oil" is available to be split between the contractor and the government at early stages in the project when total investor costs to be recovered often exceed total project revenues. The model PSA and the signed PSAs have a cost recovery limit of 70%. Under these terms, at least 30% of production will always be shared between the contractor and the government as profit oil.

TRADITIONALLY, THE PERCENTAGE OF PROFIT OIL FLOWING TO THE GOVERNMENT INCREASES WITH THE VOLUME OF PRODUCTION

Profit Oil: Once costs have been recovered, the remaining oil production, known as "profit oil", is split between the company and the government. The division is normally based on some kind of sliding scale. Traditionally, the percentage of profit oil flowing to the government increases with the volume of production (normally measured in thousands of barrels of oil per day or bopd). An alternative is to base the profit oil split on some measure of profitability. One option is the use of a measure of cumulative project expenses to cumulative project revenue: a ratio known as an "R-factor."

(3) State Equity

Many countries with production sharing systems provide an option for the host government to participate in the project as a joint owner. The size of the equity stake held by governments, or by national oil companies, ranges widely but for emerging producers tends to be between 5% and 20%. The rationale for state participation is not necessarily economic. There are no economic benefits provided by state participation that cannot be achieved through an appropriate mix of conventional taxes. Other reasons why governments might seek an equity stake includes the development of a skilled workforce, the

possibility of linking to downstream enterprises (i.e. refineries) and the commercial knowledge that could be gained from being on the "inside" of the project. As an equity partner, the government would participate on essentially the same terms as other commercial partners. Yet, there is one important difference. Governments normally delay taking up their stake until exploration efforts succeed, or even until production has begun. Where the company covers exploration (and sometimes development) costs, this is referred to as a "carried interest."

Corporate Income Tax

It is increasingly common for countries employing a production sharing system to also impose a corporate income tax. In fact, in production sharing schemes where the government's share of profit oil is small, like Malawi, corporate income tax is often the main source of government revenue over the lifecycle of the project. Income tax is assessed on "net" or taxable income, calculated as gross income less eligible expenses. Most expenses are claimed in the year in which they were incurred. Capital expenditures, however, are "depreciated" over time. There does not appear to be any petroleum-specific depreciation schedule and it is assumed the normal rates set out in the Taxation Act would apply.

Comparing the Three Sets of Fiscal Terms

The economic analysis provided in this report is based on the headline fiscal terms contained in the signed PSAs, the proposed Addendum and the model PSA. An overview of the main terms is provided in Table 1 below. Full details are provided in Annex 1.

Table : Overview of Fiscal Terms

	Signed PSA May 2014	Proposed Addendum November 2016	Model PSA March 2014
Royalty	5%	10%	12.5% 10% (deepwater)
Production Sharing			
Cost Recovery			
Limit	70%	70%	70%
Depreciation	5 years	5 years	5 years
Profit Oil			
Allocation	Combined	Production Volume	R-factor
Government Share (barrels thousands)	< 150 Production 0-12.5 = 20% 12.5-25 = 22.5% 25-50 = 25% 50-100 = 27.5% 100-150 = 30% > 150 R-factor R<1 = 20% R1-2 = 22.4% R2-3 = 24.8% R3-4 = 27.2%	0-12.5 = 20% 12.5-25 = 22.5% 25-50 = 25% 50-100 = 27.5% 100-150 = 30% > 150 = 35%	R<1 = 30% R1-2.5 = 50% R>2.5[4] = 70%
State Participation			
Percentage Stake	10%	20%	10%
Carried Interest	All costs until start of production	All costs until start of production	All costs until start of production
Corporate Tax			
Tax Rate	30%	30%	30%
Depreciation	5 years	5 years	5 years

IT IS INCREASINGLY COMMON FOR COUNTRIES EMPLOYING A PRODUCTION SHARING SYSTEM TO ALSO IMPOSE A CORPORATE INCOME TAX.

Secondary Fiscal Issues

A comprehensive economic analysis of Malawi's petroleum fiscal regime would necessarily delve into a range of what might be called secondary fiscal issues. Three specific examples are offered to illustrate the point.

First, there is a lack of clarity on the cost recoverability of the interest cost associated with financing oil field development. The accounting procedures of the model PSA (20.1.2) identify the interest on debt financing as a "non-recoverable" cost. In the signed PSA, however, this specific provision has been removed. There is, therefore, a degree of uncertainty over whether interest on debt financing is cost recoverable, or not, under the terms of the signed PSAs. While not analysed here, the recoverability of debt financing is a significant investment incentive and, in other jurisdictions, has been exploited by companies to minimize revenue payments to governments.[5]

Second, in this analysis, we have assumed that the rules for calculating eligible costs within the production sharing system (cost recovery) and within the corporate income tax system (deduction in the calculation of taxable income) are the same. However, it is not uncommon for different rules to be applied within these two systems. Examples could include rules on the pace of capital depreciation, the right to carry-forward losses and the eligibility of costs including marketing, insurance and the interest on debt financing.

Third, there is ambiguity in the current PSA on what is known as the "delivery point." When administering a petroleum fiscal regime, it is essential to know the point at which the oil changes hands from the upstream production to the transportation infrastructure (e.g. rail, pipeline, tanker). The definition of the "delivery point" is not fully specified in the model PSA or in the signed PSAs. The definition states the delivery point will be determined by the point at which the title to the Petroleum is transferred to another party, it will be as close as is practicable to the Development Area, and it will ultimately be agreed between the Contractor and the Minister.[6] The lack of specificity is likely because the appropriate mode of transportation is not yet known. This economic analysis, however, is based on an assumption the delivery point will be based in Malawi. This is a pattern seen in other landlocked countries including Chad and Uganda. Under this assumption, the transportation tariff is deducted from the sale price of the oil as part of a "netback" calculation. However, it is also possible for the transportation tariff to be treated as a cost and to be eligible for cost recovery, as is the case in Kenya, where the whole oil system is within the same country.

An analysis of these and other secondary fiscal issues is beyond the scope of this current project. Attention is drawn to these indicative examples to illustrate that a more comprehensive economic analysis would be needed in order to fully address fiscal issues contained in Malawi's production sharing agreements.

OIL FIELD SCENARIOS

The impact of individual fiscal instruments, and the performance of the overall fiscal regime, only becomes meaningful when applied to a specific project. Oil exploration in Malawi remains in the earliest stages. It is not yet clear whether commercially viable volumes of oil will be found. If oil is found, there is no indication yet of the potential volumes or of the specific locations.

In order to assess the proposed fiscal regimes against plausible oil projects in Malawi, we have developed a series of hypothetical oil fields. Initially, the intention was to develop four fields: a larger and a smaller field onshore, and a larger and smaller field in Lake Malawi. An initial analysis revealed, however, given the very high costs of exploration and development of an oil field project in Lake Malawi, a smaller sized project would simply be uneconomic. We have, therefore, developed three oil field scenarios: a large onshore project with an assumed 250 million barrels of recoverable reserves; a small onshore project with an assumed 50 million barrels of recoverable reserves; and, a large offshore project with an assumed 250 million barrels of recoverable reserves.

An overview of the three scenarios is provided in the section below.

Large Onshore Field

Exploration
Conventional land exploration similar to Uganda and Kenya will be required following onshore seismic surveys. We assume at least twenty-six exploration and appraisal wells and two seismic programs would be needed to find and prove a successful onshore large field discovery. We estimate each well will likely cost around $28,000,000 (based on data from Tullow's Uganda exploration wells).[7] With seismic costs and wells, total exploration costs of $750,000,000 are anticipated for the onshore large-field case.

Development
We consider a large field development in the Lower Shire Valley in the south of Malawi. The development is visualized as similar to the Buliisa development in Uganda. The field scenario would have an offtake of 65 thousand barrels per day (mbd), equivalent to 250 million barrels of recoverable reserves (mmbbl). The production profile will ramp up over two years.

Transportation
This volume of oil could be exported by a 674km pipeline to Nacala in Mozambique, constructed along the same route used to export Mozambican coal.

Cost Summary

Exploration and appraisal costs:	$3.00/bbl
Upstream capital costs:	$7.32/bbl (Uganda Block EA3A Kingfisher analogue)
Upstream operating costs:	$8.69/bbl (Uganda Block EA3A Kingfisher analogue)
Pipeline tariff:	$8.00/bbl (Benchmarked against Chad Cameroon)
Total costs estimate:	$27.01/bbl

THE IMPACT OF INDIVIDUAL FISCAL INSTRUMENTS, AND THE PERFORMANCE OF THE OVERALL FISCAL REGIME, ONLY BECOMES MEANINGFUL WHEN APPLIED TO A SPECIFIC PROJECT.

Small Onshore Field

Exploration
Conventional land exploration similar to Uganda and Kenya will be required following onshore seismic surveys. We assume at least two exploration wells would be needed along with four appraisal wells in the event of a successful small field discovery. Each well will likely cost around $28,000,000 (based on Tullow's Uganda exploration wells)[8]. With seismic costs and wells, exploration costs of $180,000,000 are anticipated for the onshore small field scenario.

Development
We consider a small field development in the Lower Shire Valley in the south of Malawi. The development is visualized as a smaller version of the Buliisa development in Uganda. This field scenario should have an offtake of 13 thousand barrels per day, equivalent to 50 million barrels of reserves. The production profile will ramp up over two years.

Transportation
This volume of oil could be exported by train to the port of Nacala in Mozambique.

Cost Estimates

Exploration and appraisal:	$3.60/bbl
Upstream capital costs:	$15.60/bbl (Uganda Block EA2 Kaiso-Tonya[9] analogue)
Upstream operating costs:	$11.70/bbl (Uganda Block EA2 Kaiso-Tonya analogue)
Rail tariff:	$2.50/bbl (See Early Oil from Turkana, KCSPOG, 2016)[10]
Total cost estimate:	$33.40/bbl

Large Offshore Field

Offshore Exploration
A semi-submersible drilling rig would be required due to water depths in the Lake. There is a significant barrier to bringing a suitable drilling rig into Lake Malawi: a working drilling rig would have to be dismantled, transported by rail to the south of the Lake, and reassembled and recommissioned. A multi-well program would be required to justify the costs of transporting a drilling rig. It seems clear that offshore exploration would not go ahead until onshore exploration has proved that oil exists. Then offshore seismic would need to be run to establish the potential for offshore oilfields and potential commerciality confirmed before any offshore exploration wells are contemplated.

We assume at least one or two exploration wells would be needed along with four appraisal wells in the event of a successful discovery. We estimate each well will likely cost around $250,000,000 due to the cost uplift for Lake Malawi and the difficulty of getting a suitable rig to the location[11]. With seismic costs and wells, total exploration costs of $1,600,000,000 are anticipated for the offshore large field scenario.

Offshore Development
We consider a large offshore development in the west side of the northern part of Lake Malawi.[12] We assume a 250 million barrel oilfield (mmbbl) with an offtake of 75 thousand barrels per day (mbd).

Development would most likely be by subsea wells, tied back to a floating production storage and offloading (FPSO) unit or tethered leg platform. The production profile will ramp up over two years.

Transportation
For this volume of oil, a 660km pipeline to Mtwara port in Tanzania would be required for export.

Cost Estimates

Exploration and appraisal:	*$6.40/bbl*
Upstream capital costs:	*$19.00/bbl (USEIA Gulf of Mexico deepwater data not uplifted)*
Upstream operating costs:	*$11.00/bbl (USEIA Gulf of Mexico deepwater data not uplifted)*
Pipeline tariff:	*$8.00/bbl (Benchmarked against Chad Cameroon)*
Total cost estimate:	*$44.40/bbl*

Oil Price

Plausible estimates of future oil price are required for estimating future government revenue. It is widely accepted that even the best oil price forecasts are little better than educated guesses. According to former BP CEO John Browne, the future oil price is "inherently unpredictable."

The objective in fiscal regime analysis is not to try to predict future prices, but rather to test the different sets of fiscal terms under a range of potential prices. Forecast prices are for Brent crude, the world's most widely used benchmark price.

The oil price used for the base case analysis is $60 per barrel. This is somewhat lower than the current price for Brent crude and is based on futures market prices for 2025.[13] We also test the different fiscal regimes at $80 per barrel and $100 per barrel.

COMPARISON OF FISCAL REGIMES AGAINST SCENARIOS

This section compares the fiscal regimes as set out in the signed PSAs, the proposed Addendum and the model PSA against the three hypothetical oil fields described in the section above. The comparison is based both on the implications for government revenue and on the attractiveness as an investment for the company.

For the government, we focus on three key metrics: government take, the timing of government revenue and how government revenues respond to increases in profitability (progressivity).

1. The government take is the share of divisible (after-cost) revenue allocated to the government, as compared to the company, over the lifecycle of the project.
2. It is important to understand when in the project lifecycle the government receives the bulk of its revenue. As companies can normally recover their investments quickly, the bulk of government revenue can often become significant only after the project has been producing for several years.
3. Ideally, the government's share of net benefits should increase for more profitable projects. As many fiscal regimes do not have a progressive tax, the government would not capture a higher share when commodity prices skyrocket.

For the company, we also focus on three key metrics measured from the time of the final investment decision (FID): net present value (NPV), internal rate of return (IRR) and payback.

1. Net present value is the value in today's money of future cash flows discounted to take into account the cost of capital (discount rate). For the base case analysis, we assume a discount rate of 10%.
2. The internal rate of return is the discount rate that would generate an NPV of zero. It provides an indication of the company's return on their investment.
3. Payback is the number of years from the start of production after which the company has recovered its initial investment.

The Economics of Large Onshore Development

The large onshore development is the base case for this report. With total project costs estimated around $27 per barrel, we would expect the project to generate good results for both the company and the government. Table 2 below provides a summary of the modelling results for the three sets of fiscal terms.

Table : Large Onshore Fiscal Regime Modelling Results ($60/bbl)

(USD millions)	Signed PSAs	Proposed Addendum	Model PSA
Government Revenue			
Royalty	650	1300	1625
Profit Oil	1849	1702	3246
Corporate Income Tax	1813	1668	1126
NOC	448	825	280
Total	4761	5495	6277
Government Take	58%	67%	76%

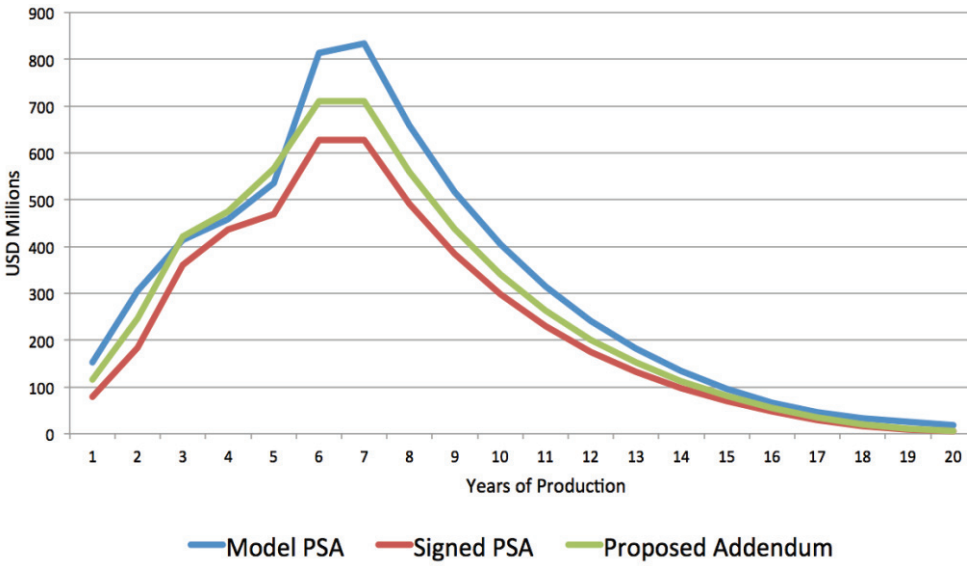
Company Economics			
IOC Cashflow (Field Life $m)	3487	2753	1971
NPV $m	1240	958	727
IRR (%)	23%	21%	19%
Discounted Payback (years)	7	7	7

Overall, the project economics for a large onshore oil field presents an attractive investment opportunity for the company under all three fiscal scenarios. The NPV is strongly positive and the IRR ranges from 19% to 23% depending on the scenario. The company recovers the costs of its investment within the first seven years.

For the government, there are very significant differences across the three fiscal scenarios. The government take for the signed PSAs is 58% and increases to 67% under the proposed Addendum terms, and to 76% under the model PSA terms. Total government revenue over the lifecycle of the project ranges from a low of $4.8 billion under the signed PSA terms, to $5.5 billion under the proposed Addendum terms, and to $6.3 billion under the model PSA terms.

The year-on-year differences are shown in Figure 2 below. As the main fiscal instruments are the same across the three different fiscal regimes, there is relatively little difference in the profile that shows the timing of government revenues.

Figure : Annual Government Revenue Generated by the Three Fiscal Regimes



THE GOVERNMENT TAKE FOR THE SIGNED PSAS IS 58% AND INCREASES TO 67% UNDER THE PROPOSED ADDENDUM TERMS, AND TO 76% UNDER THE MODEL PSA TERMS

The oil price used for the base case analysis is $60 per barrel. In order to test the progressivity of the different fiscal regimes, we have generated analyses at $80 per barrel and $100 per barrel. The results are shown in below.

Table 3: Large Onshore Field Government Revenues at Different Oil Prices

	Signed PSAs		Proposed Addendum		Model PSA	
	Revenue	Take	Revenue	Take	Revenue	Take
$60	4761	58%	5495	67%	6277	76%
$80	7422	56%	8523	64%	9855	74%
$100	10096	55%	11563	63%	14073	77%

The results for the signed PSAs and the proposed Addendum terms show that these two fiscal regimes are regressive. This means while overall government revenue increases with the profitability of the project, the share of divisible revenue flowing to the government decreases. The model PSA is moderately progressive, particularly at higher oil prices. This is due to the allocation of profit oil based on an R-factor which is sensitive to the overall profitability of the project. Progressivity under the R-factor mechanism would be improved if additional tranches or steps were added between the bottom and top allocations.

The Economics of Small Onshore Development

Ideally, a fiscal regime should be well calibrated not only to large profitable projects but also to projects that are smaller and have higher costs. With modest oil production and total estimated project costs of $33.40 per barrel, we would expect the economics of this field scenario to be challenging. Table 4 below provides a summary of the modelling results for the three sets of fiscal terms.

Table 4: Small Onshore Fiscal Regime Modelling Results ($60/bbl)

(USD millions)	Signed PSAs	Proposed Addendum	Model PSA
Government Revenue			
Royalty	144	288	359
Profit Oil	255	227	436
Corporate Income Tax	297	263	190
NOC	87	157	53
Total	782	935	1039
Government Take	59%	70%	78%
Company Economics			
IOC Cashflow (Field Life $m)	548	395	291
NPV $m	56	-3	-37
IRR (%)	12%	10%	9%
Discounted Payback (years)	12	20	na

FROM A GOVERNMENT REVENUE PERSPECTIVE, THE THREE DIFFERENT FISCAL REGIMES FOLLOW A SIMILAR PATTERN WITH THE SIGNED PSAS GENERATING THE LOWEST GOVERNMENT TAKE AND THE MODEL PSA GENERATING THE HIGHEST.

From a government revenue perspective, the three different fiscal regimes follow a similar pattern with the signed PSAs generating the lowest government take and the model PSA generating the highest. The small onshore case, however, illustrates the importance of analysing the wider project economics and the implications for the investor.

The results for the signed PSA terms are marginal from a company point of view. Looking forward from FID, the project generates a small positive NPV ($56 million) and an IRR of 12%. But this does not take into account the sunk costs of exploration. Even then, under this scenario, it takes 12 years for the company to achieve payback.

The small onshore field does not generate positive economics under either the proposed Addendum or the model PSA terms. Company NPV is negative in both cases.

Rerunning the analysis under a higher oil price scenario improves the company economics, as shown in Table 5 below.

Table 5: Small Onshore Field Company Economics at Different Oil Prices

	Signed PSAs		Proposed Addendum		Model PSA	
	NPV	IRR	NPV	IRR	NPV	IRR
$60	56	12%	-3	10%	-37	9%
$80	244	17%	158	15%	95	13%
$100	425	21%	313	18%	211	16%

As mentioned above, while it is important to assess the fiscal regime at higher oil prices, it is clear that all three sets of fiscal terms are not well designed for a smaller oil project in today's lower oil price environment. Based on this analysis, it is unlikely an oil company would proceed with a small onshore development under any of the three sets of fiscal terms. As Malawi considers revisions to the petroleum fiscal regime, there would be value in looking at fiscal regime options that improve the economics for small field development even while ensuring the government secures the full revenue benefits from larger and more profitable projects.

The Economics of Large Offshore Development

The economics of the large offshore development are even more problematic than the small onshore field. Although production volumes are high, project costs before fiscal terms are taken into account are also very high. We estimate costs at $44.40 per barrel. With base case oil price of $60 per barrel, the margin is obviously very small even before taking into account the fiscal terms. Table 6 below provides a summary of the modelling results for the three sets of fiscal terms.

Table 6: Large Offshore Fiscal Regime Modelling Results ($60/bbl)

(USD millions)	Signed PSAs	Proposed Addendum	Model PSA
Government Revenue			
Royalty	650	1300	1300
Profit Oil	881	814	1667
Corporate Income Tax	897	821	536
NOC	237	357	93
Total	2665	3293	3596
Government Take	68%	84%	92%
Company Economics			
IOC Cashflow (Field Life $m)	1235	607	304
NPV $m	-242	-510	-611
IRR (%)	9%	7%	6%
Discounted Payback (years)	na	na	na

THE ECONOMICS OF THE LARGE OFFSHORE DEVELOPMENT ARE EVEN MORE PROBLEMATIC THAN THE SMALL ONSHORE FIELD

Under all three sets of fiscal terms, company NPV is negative and payback of the initial investment is not achieved over the lifecycle of the project. Preliminary analysis suggests that even if larger volumes of oil were to be found, the underlying economics would continue to be very challenging for the company.

As would be expected, the economics do improve under higher oil price assumptions.

Table : Large Offshore Field Company Economics at Different Oil Prices

	Signed PSAs		Proposed Addendum		Model PSA	
	NPV	IRR	NPV	IRR	NPV	IRR
$60	-242	9%	-510	7%	-611	6%
$80	789	14%	403	12%	294	12%
$100	1734	18%	1219	16%	970	15%

The results of the large offshore field indicate the real issue is the underlying economics of a high cost project in a lower price environment. Even at $80 per barrel, the signed PSA terms generate only a marginal return for the company. Revisions to the fiscal regime are unlikely to be able to overcome the very high cost of oil exploration and production in a landlocked lake, hundreds of kilometres from the coast.

SUPPLEMENTARY ANALYSIS OF THE SIGNED PSAS

The signed PSAs were not subjected to a comprehensive economic review by all relevant parts of the Malawi government. These contracts contain two provisions that are highly unusual and warrant specific analysis. First, two separate mechanisms are employed to allocate the volume of production, known as profit oil, after costs have been recovered. Second, an unspecific commitment is made to negotiate, in good faith, a reduction to the rate of corporate tax. Each of these provisions is analysed, in turn, in the section below.

Production and R-factor Profit Oil Splits

The allocation of profit oil, after costs have been recovered, is commonly based on a sliding scale. In many petroleum fiscal regimes, the allocation of profit oil to the government increases as the volume of production increases. In other petroleum fiscal regimes, the allocation of profit oil is based on a measure of profitability based on the ratio of cumulative project costs to cumulative project revenues (known as an "R-factor").

The model PSA uses only an R-factor to allocate profit oil between contractor and government. The proposed Addendum uses only the production volume to allocate profit oil. The signed PSAs, however, combine these two allocation mechanisms. For production up to 149,999 barrels per day, the allocation is based on production volume. At production volume over 150,000 barrels per day, the profit oil allocation shifts to an R-factor.

IN MANY PETROLEUM FISCAL REGIMES, THE ALLOCATION OF PROFIT OIL TO THE GOVERNMENT INCREASES AS THE VOLUME OF PRODUCTION INCREASES

The large onshore and large offshore scenarios we prepared for this project do not cross the 150,000 barrels of oil per day production threshold. In order to assess the economic impact of the transition from production to R-factor profit oil allocations, we devised a larger onshore field with recoverable reserves of 577 million barrels. We then tested this field with peak production of both 149,999 barrels and 150,001 barrels. The results for large field development onshore at $60 per barrel are shown in Table 8 below.

Table 8: Comparing Mega-Onshore Field (577 Million Barrels) Profit Oil Splits

	Peak Production 149,999	Peak Production 150,0001
Government Profit Oil $	4997	4553
Government Profit Oil %	26%	23%
Total Government Revenue $	11,809	11,533
Government Take %	59%	58%
Company NPV	2466	2603
Company Rate of Return	22%	22%

Over the lifecycle of the project, the government generates less revenue under the R-factor than under the production volume profit split.

The differences between the production and R-factor profit oil split are particularly acute in the early years of production. Total government revenues over the first ten years of production are shown in Table 9 below.

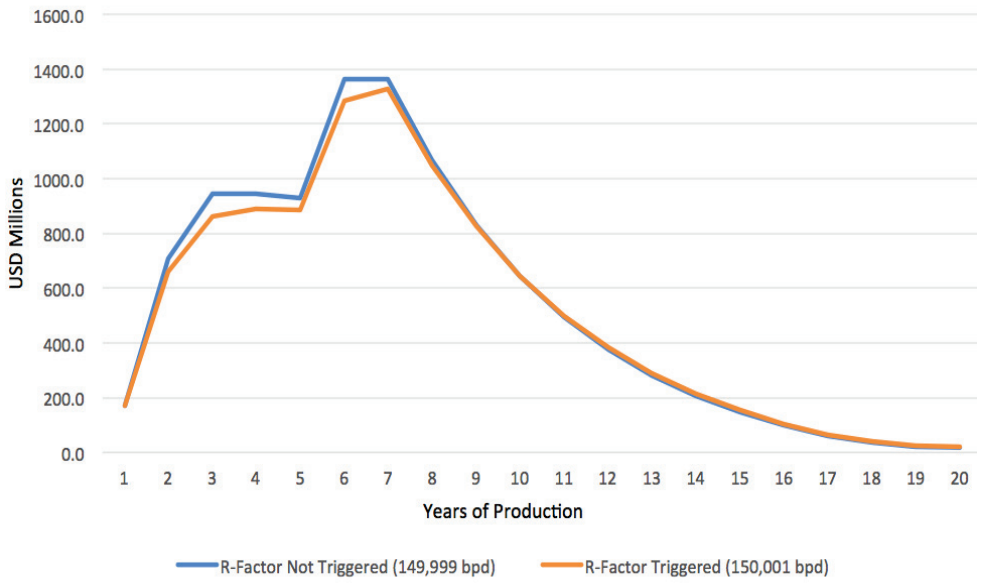
Table 9: Comparing Mega-Onshore Field (577 Million Barrels) Profit Oil Splits

Year	1	2	3	4	5	6	7	8	9	10
149,999	170.9	706.7	945.5	945.5	929.2	1362.7	1362.7	1066.6	829.5	643.9
150,001	170.9	661.3	862.5	891.5	884.8	1284.4	1326.4	1048.4	824.7	644.7

In the first year of production, and again by around year 10, the two systems generate equal government revenue. In the intervening years, however, the R-factor allocation generates less government profit oil and, therefore, less overall government revenue. With production just below 150,000 barrels of oil per day, the government allocation of profit oil is at its maximum of 30%. However, if production exceeds 150,000 barrels of oil per day, government profit oil drops to only 20% until cumulative revenues exceed cumulative costs.

Although the R-factor scenario results in a slight increase in production, from years 2 through 10 it generates $363.5 million less in government revenue ($8,792 million versus $8,428 million). The year-by-year differences are shown in Figure 3 below.

Figure 3: Annual Government Revenues from Production and R-factor Profit Oil Splits



As is expected, allocating profit oil through both a production and R-factor split yields results that are clearly inconsistent with good fiscal regime design. Both allocation mechanisms, on their own, can generate an appropriate allocation of profit oil to both company and government. The combination, however, results in the unusual circumstance where an increase in oil production can actually result in a decrease in government revenue, the opposite of what would normally be expected. The situation would only arise if a very large oil field were to be found. Under those circumstances, however, it would be in the company's interest to design their development strategy in order to take advantage of this fiscal anomaly.

A Negotiated Reduction in the Rate of Corporate Income Tax

The fiscal regimes proposed in Malawi's oil contracts all contain a corporate income tax to be paid by the oil company. In the model PSA, and in the proposed Addendum, the corporate income tax rate is set at the standard 30%.

Article 30.10 of the signed PSAs, however, obligates the government to negotiate, in good faith, a reduction to the rate of corporate income tax at the contractor's request, made at any time at least two years following the signing of the contract.

This is an unusual, open-ended commitment. There is no indication of how substantial a reduction in the rate of corporate tax would be required in order to

meet this "good faith" commitment. It is also an important provision as, for the signed PSAs, corporate tax is one of the main sources of government revenue generating 38% of the total (compared with 39% for government profit oil).

In order to provide a sense of the potential implications of this provision, we consider the economic impact of three reductions in the rate of corporate tax of 2%, 5% and 10% (based on the large onshore scenario at $60/bbl with the signed PSA terms). We show the results over the lifecycle of the project for both corporate tax payments and for total government revenue.

Table : Assessing the Revenue Impact of Reductions in the Rate of Corporate Tax (USD Millions)

Corporate Tax Rate	30%	28%	25%	20%
Corporate Tax Revenue	1813	1692	1511	1209
Total Government Revenue	4761	4649	4480	4199
Overall Difference	0	112	281	562
Government Take %	58%	56%	54%	51%

As would be expected, any reduction in the rate of corporate tax would have a significant impact on government revenue. For the large onshore scenario, a 2% reduction in the rate of tax would result in a loss of around $112 million in government revenue. A more substantial reduction of 10% would result in a loss of around $562 million.

REGIONAL BENCHMARKING

When establishing the fiscal terms in a production-sharing contract, the objective of the government is to attract inward investment for exploration (and hopefully production) of oil while at the same time seeking to maximize the revenues that would flow to the government from that project. It is a difficult balance to strike.

In the section above, we have sought to analyse the competitiveness of Malawi's fiscal regime against plausible projects that could conceivably be developed in the country. A second approach to analysing competitiveness is to compare fiscal regimes with other countries.

The selection of comparison countries is important. While no two countries are exactly the same, it is generally suggested that countries should be compared to their "peers." This means one might compare Nigeria with Angola, as they are both among Africa's leading oil producers. The comparison is appropriate because a company might find itself in a situation where it was considering an investment in either Nigeria or Angola.

A similar logic applies to countries where no oil is yet produced. Known as "frontier" countries, it is generally accepted these countries will be required to offer more generous fiscal terms than existing producers in order to attract what would be considered higher risk exploration activities.

Two obvious peer countries in the East African region are Kenya and Uganda. Both countries have now found commercially viable quantities of oil. As a result, both countries have decided to adopt tougher fiscal terms.[14] This is a well-established pattern where countries decide to ask for a larger share of after-cost project revenues once the prospects of oil production have been proven. We, therefore, look to the fiscal terms that Kenya and Uganda offered to companies before the commercial discoveries were made.

The Fiscal Regimes in Kenya and Uganda

Kenya and Uganda both employ fiscal regimes in their petroleum sectors based on the production sharing system. Uganda, like Malawi, has opted for a hybrid system that incorporates a royalty, a corporate income tax, and state equity participation alongside the production sharing system. Kenya, in contrast, operates a traditional production sharing system without any royalty or corporate income tax. In addition to a state equity participation, the Kenyan fiscal regime also includes a modest "additional profits tax" that is triggered with oil prices above $50 per barrel. A summary of the fiscal terms from Kenya and Uganda is provided in Table 11 below.

Table 11: Summary of Fiscal Terms for Kenya and Uganda

	Kenya PSA 10BA 2008	Uganda PSA EA1 2004
Royalty	na	<2500 bpod: 5% 2500 to 5000 bopd: 7.5% 5000 to 7500 bopd: 10% >7500 bopd: 12.5%
Production Sharing		
Cost Recovery Limit	60%	60%
Government Profit Oil	<10,000 bopd: 50% 10,000 to 20,000 bopd: 55% 20,000 to 30,000 bopd: 60% 30,000 to 50,000 bopd: 63% 50,000 to 100,000 bopd: 68% >100,000 bpd: 78%	<5000 bopd: 45% 5000 to 10000 bopd: 47.5% 10000 to 20000 bopd: 50% 20000 to 30000 bopd: 57.5% 30000 to 40000 bopd: 62.5% >40000 bopd: 67.5%

State Participation		
Percentage Stake	20%	15%
Carried Interest	Partial (through development)	Partial (through development)
Corporate Tax		
Rate	na	30%
Capital Depreciation	na	6 years
Additional Profits Tax	26% above $50/bbl	na

Comparative Analysis

In the section below, we compare the modelling results under the base case scenario (large onshore field at $60 per barrel) for the terms contained in the signed PSAs and the proposed Addendum with the fiscal terms set out above for Kenya and Uganda.

Table 12: Comparative Analysis for Malawi, Kenya and Uganda

(USD millions)	Malawi Signed PSAs	Malawi Proposed Addendum	Kenya 10BA 2008	Uganda EA1 2004
Government Revenue				
Royalty	650	1300	na	1472
Profit Oil	1849	1702	4443	3639
Corporate Income Tax	1813	1668	0	782
Additional Profits Tax	na	na	141	na
NOC	448	825	883	416
Total	4761	5495	5467	6310
Government Take	58%	67%	66%	77%
Company Economics				
IOC Cashflow (Field Life $m)	3487	2753	2781	1938
- NPV $m	1240	958	1039	666
- IRR (%)	23%	21%	23%	18%
- Discounted Payback (years)	7	7	8	8

Assessing the lifecycle performance of the four different fiscal regimes, a clear pattern emerges: Uganda has the most stringent fiscal terms, and there is broad comparability between the Kenyan terms and those set out in the proposed Addendum. Malawi's signed PSAs are significantly more generous to the company.

According to the IMF, petroleum-producing countries could expect a government take of 65-85%.[15] The lower end of this spectrum would be expected for contracts signed before a country has experienced a commercial oil discovery. It is widely recognized Uganda has unusually tough terms for a "frontier" country.[16] Kenya's 2008 PSA and the terms contained in Malawi's proposed Addendum fall within the expected range, while the signed PSA terms appear to generate an unusually low government take.

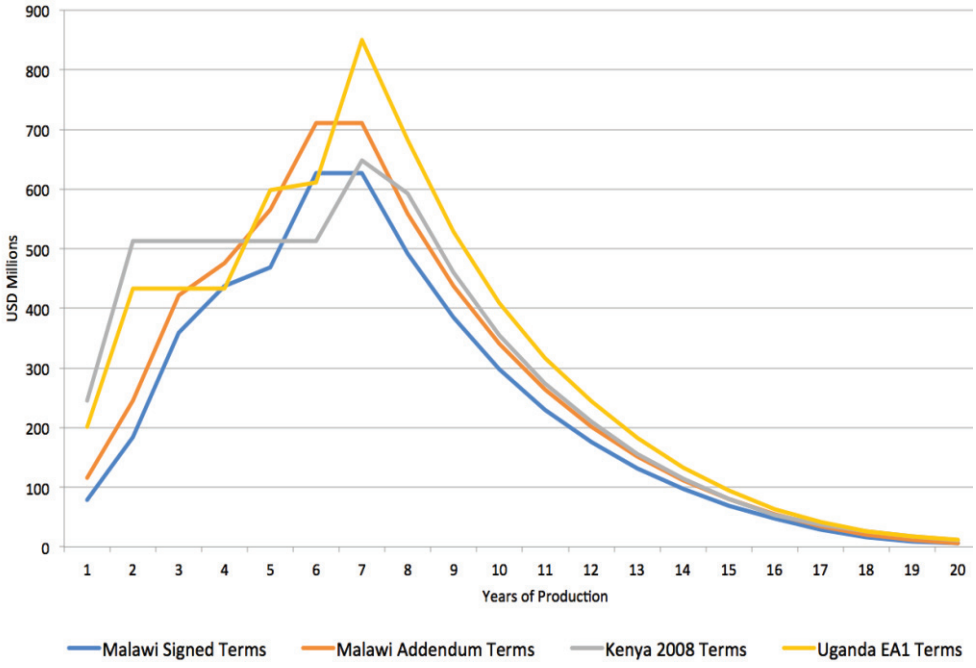
It is common for the fiscal terms in a production sharing agreement to reward companies early in the lifecycle of the project, with the bulk of government revenue coming on-stream somewhat later in the project lifecycle. The "effective royalty rate" is one measure of the timing of revenue payments. It assesses the minimum share to the government of overall production (normally in the first years after project start-up) from royalties and the government's share of profit oil.[17] According to a leading analyst, the global average effective royalty rate for production sharing contracts is around 23%.18 The effective royalty rates for the four sets of fiscal terms under consideration are set out in

Table 13: Effective Royalty Rates: Malawi, Kenyan and Ugandan PSAs

	Malawi Signed PSAs	Malawi Draft Addendum	Kenya 10BA 2008	Uganda EA1 2004
Effective Royalty Rate	12%	17%	24%	33%

The impact of the effective royalty rate can be seen in the year-on-year revenue project in the table above. Both the Kenyan and Uganda fiscal regimes generate more government revenue in the early years of the project.

Figure 4: Regional Benchmarking: Comparing Annual Government Revenue over Lifecycle



Fiscal regimes can also be compared on the basis of their responsiveness to differing oil prices. As noted above, a well-designed fiscal regime should be progressive: it should allow the government to capture a larger share of divisible (after cost) revenue as the profitability of the project increases.

Table 14: Large Onshore Field Government Revenues at Different Oil Prices – Regional Benchmarking

	Malawi Signed PSAs		Malawi Draft Addendum		Kenyan PSA		Uganda PSA	
	Revenue	**Take**	**Revenue**	**Take**	**Revenue**	**Take**	**Revenue**	**Take**
$60	4761	58%	5495	67%	5467	66%	6310	77%
$80	7422	56%	8523	64%	9042	68%	10107	76%
$100	10096	55%	11563	63%	12685	70%	13921	76%

While a progressive fiscal regime is clearly preferable, it is less common than might be expected. Of the four fiscal regimes examined here, only the Kenyan PSA with its oil price linked additional profits tax generates a higher government take as oil price rises.

CONCLUSIONS AND RECOMMENDATIONS

The oil exploration phase in Malawi remains in its earliest stages. To date, there is no indication commercially viable quantities of oil exist in the country. However, as the contracts set out the terms for oil exploration, development and production are signed before exploration begins, it is important for Malawi to develop a well-designed petroleum fiscal regime even while the prospects for the sector remain highly uncertain.

Recommendation 1: Malawi should work towards an updated Petroleum Act and a national petroleum policy in order to establish a clear legal and policy foundation on which to promote the development of the sector.

Malawi chose to develop a comprehensive model PSA in order to compensate for an out-of-date legal framework. The development of sector legislation and a national policy framework, as has now been done in the solid mineral sector, would provide a consistent foundation for the development of the sector and the negotiation of project-specific PSAs.

Recommendation 2: A model PSA with well-calibrated fiscal terms provides a sound basis for negotiations with international oil companies. Malawi should finalize the development of the model PSA, including a comprehensive review of the fiscal provisions, and use that document as the foundation for all future negotiations.

Substantial work was devoted to the development of the model PSA. The government was able to draw on significant international support from the Commonwealth Secretariat, the International Monetary Fund (IMF), the African Legal Support Fund, the University of Dundee, and the International Senior Lawyers Project. A hybrid fiscal system was selected, based on a production sharing system and including a royalty and corporate income tax as well as state equity participation. However, the model PSA was not finalized and, specifically, a full economic analysis of the fiscal terms was not undertaken.

Recommendation 3: The government of Malawi should further strengthen its capacity to undertake an economic analysis of the fiscal terms contained in existing and future production sharing contracts. The economic model prepared as part of this project is a tool that can assist in meeting this objective.

A well-designed fiscal regime should find an appropriate balance between attracting inward investment and generating government revenue. Economic modelling is an essential component of fiscal regime design, as the full implications of the interactions between different fiscal instruments can be difficult to anticipate. The fiscal regime should be calibrated to plausible projects in the Malawian context.

Recommendation 4: As part of revisions to the petroleum fiscal regime, Malawi should reconsider the use of the R-factor approach to the allocation of profit oil, as proposed in the model PSA, in order to ensure the government would capture a greater share of windfall profits.

A WELL-DESIGNED FISCAL REGIME SHOULD FIND AN APPROPRIATE BALANCE BETWEEN ATTRACTING INWARD INVESTMENT AND GENERATING GOVERNMENT REVENUE.

For the highly profitable large onshore scenario, the fiscal terms contained in both the proposed Addendum and in the model PSA provide an adequate return for the investor and also generate a reasonable share of revenue for the government. The modelling results, therefore, confirm that a tightening of the fiscal terms, in comparison to the signed PSA, is both possible and appropriate. In addition to securing a higher government take, fiscal regime revisions should be considered that would make the fiscal regime progressive: that would generate a higher government take when project profitability increases. The most common approach to achieve this objective within a production sharing system is the adoption of an R-factor as the basis for the allocation of profit oil.

Recommendation 5: As Malawi considers revisions to the petroleum fiscal regime, it should benchmark against the terms employed in other jurisdictions before commercial quantities of oil have been found. Comparative analysis with contracts from Kenya and Uganda signed before suggests that Malawi should target a government take of around 70%.

According to the IMF, a government might expect to secure between 65% and 85% of the divisible (after-cost) revenue from a petroleum project. Countries with no history of a commercial oil discovery could expect to be on the lower end of this spectrum. The fiscal terms contained in the signed PSAs fall short of these expectations. Modelling results under the base case scenario show that under the agreed terms, the government take is below 60%. While governments routinely offer more generous terms in advance of a first commercial oil discovery, the terms in the signed PSAs generate less government revenue than those in Kenyan and Uganda contracts signed before oil discoveries were made.

THE TERMS CONTAINED IN THE PROPOSED ADDENDUM IMPROVE THE GOVERNMENT'S POSITION, BUT STILL DO NOT ENABLE THE GOVERNMENT TO SECURE A LARGER SHARE OF THE DIVISIBLE REVENUE FOR HIGHLY PROFITABLE PROJECTS.

Recommendation 6: The government of Malawi should build on previous efforts to renegotiate the fiscal terms contained in the already signed PSAs. The objective should be to ensure the government protects its revenue interests and secures fiscal terms that generate an increased share of revenue for the government, particularly for projects that are highly profitable.

The fiscal terms contained in Malawi's three signed PSAs are based on the same basic instruments included in the model PSA. The specific provisions, however, are more generous for the contractor than those originally envisaged in the model PSA. The terms associated with the proposed Addendum of late 2016 are more stringent and improve the economic position of the government. This analysis concludes the terms contained in the signed PSAs are more generous than necessary as applied to a large onshore oil field. The terms contained in the proposed Addendum improve the government's position, but still do not enable the government to secure a larger share of the divisible revenue for highly profitable projects.

Recommendation 7: The provisions in the signed PSAs relating to profit oil allocation and a potential reduction in the rate of corporate income tax fall outside the bounds of international good practice. The government of Malawi should, therefore, seek to remove these two provisions, as appears to have been the objective in negotiations on the proposed Addendum.

There are two unusual provisions in the signed PSAs that warrant specific attention. First, profit oil is allocated through two different systems depending on the volume of oil produced. For production under 150,000

barrels of oil per day, profit oil is allocated based on the volume of production. Above that level, profit oil is allocated based on the ratio (R-factor) of cumulative expenses to cumulative revenues. The result is a counter-initiative situation where government revenue would actually fall as the project becomes more profitable. Second, the signed PSAs contain a provision that the government will, in good faith, negotiate a reduction to the established 30% rate of corporate income tax. No clarity is provided on the scale of the potential reduction. Nevertheless, this provision holds the potential to cost the government hundreds of millions of dollars in lost revenue.

Recommendation 8: Consideration could be given to revising the fiscal terms as they impact on smaller projects. Specific fiscal instruments could be fine-tuned to make smaller projects economically viable even while protecting government revenues for larger and more profitable projects.

The fiscal terms contained in the signed PSAs, the proposed Addendum and the model PSA do not perform well against the small onshore scenario. The marginal economic results for the small onshore field are problematic as the development of Malawi's petroleum sector is most likely to start with smaller projects that provide oil companies with the confidence to continue to invest in exploration.

Recommendation 9: Further review of the fiscal terms applicable to deepwater projects may be appropriate. Given the very high costs of exploration in the Lake and the very challenging economics for deepwater projects in a lower oil price environment, this review can likely be pursued after onshore discoveries have proven the availability of commercial quantities of oil in the country.

The economic challenges associated with oil production in Lake Malawi are more fundamental. Deepwater offshore exploration is very expensive. There would be a significant cost increase associated with operating in a land-locked lake hundreds of kilometres from the East African coast. As offshore oil exploration would involve very high costs and very high risks, it seems likely it would only be considered once Malawi's oil potential had been proven through large onshore developments. Even then, oil production in the lake is likely to prove uneconomic in the lower oil price environment that is currently envisaged.

ANNEX 1: FISCAL REGIME MODELING ASSUMPTIONS

Development Scenarios

Model Input				Reference / Rationale
Development Scenarios	**Offshore Large**	**Onshore Small**	**Onshore Large**	
Production				
Base Reserves	250mmbbls	50mmbbls	250mmbbls	Scenarios of assumed "proven reserves", developed based on analogies with other African Rift Valley countries.
Field Production Life	25 years	25 years	25 years	PSA has 5 years from date of grant. This assumes 5-year extension.
Production Profile	75 mbd Plateau (Maximum offtake)	13 mbd Plateau (Maximum offtake)	65 mbd Plateau (Maximum offtake)	Revised from Scenario proposal based on KAPSARC study of Kaiso-Tonya EA2 and Kingfisher EA3A in Uganda for onshore and slightly increased offtake for offshore scenario.
Costs				
Exploration ($)	$1600 million ($6.4/bbl)	$180 million ($3.6/bbl)	$750 million ($3.0/bbl)	Based on the assumed view of minimum exploration and appraisal costs to find and prove up each discovery.
Development ($)	$19/bbl	$15.6/bbl	$7.32/bbl	Based on: - EIA Reported deepwater Gulf of Mexico costs for Onshore Large (with no special uplift for Lake Malawi in mid-continent) - Kaisa-Tonya costs in Uganda Block EA2 for Offshore Small - Kingfisher costs in Uganda Block EA3A for Offshore Large
Operating ($/a)	$112.25/annum	$23.88/annum	$88.65/annum	Fixed annual opex required to match opex per barrel for the whole of field life from: - EIA Reported deepwater Gulf of Mexico costs for Onshore Large

				(with no special uplift for Lake Malawi in mid-continent) - Kaisa-Tonya costs in Uganda Block EA2 for Offshore Small - Kingfisher costs in Uganda Block EA3A for Offshore Large
Price				
Brent Crude Price	$60/bbl Brent	$60/bbl Brent	$60/bbl Brent	New York Mercantile Exchange (NYMEX) CME Group Brent Futures prices (dated December 2025), 19 January 2018, is $59.46/bbl, rounded up to $60/bbl.
Discount to Brent	$0/bbl	$0/bbl	$0/bbl	As no information on Malawi crude oil quality is available, due to the lack of exploration, oil quality is assumed similar to Brent, so the discount is $0/bbl.
Transport Tariff	$8/bbl	$2.5/bbl	$8/bbl	The Delivery point is not specified in the PSAs. We assume that the Delivery Point is inside Malawi and that the transportation tariff functions as a discount to oil price. Large field assumes pipeline transportation, tariff level by analogy with Chad Cameroon. Small field assumes rail transportation in line with Kenya EOPS assumption. No transit fee in excess of transportation costs is assumed.

Fiscal Terms – Signed PSAs

Fiscal Terms-Signed PSAs		
PSA Terms	Block 5	Royalty: 5% Cost Recovery Limit: 70% Development Depreciation for Cost Recovery: 20% per annum starting year of spend or 1st Production (whichever the latter) Profit Splits to Government of Malawi:

		Production 0 to 12,499 bpd: 20% Production 12,500 to 24,999 bpd: 22.5% Production 25,000 to 49,999 bpd: 25% Production 50,000 to 99,999 bpd: 27.5% Production 100,0000 to 149,999 bpd: 30.0% Above 150,000 bpd instead of profit share an R-factor is applied with respect to all profit petroleum. R-factor (n+1) = eX / eY Where: "eX" is the cumulative sum of all contract revenues earned by the Contractor either from Cost Recovery or Profit Oil from inception to the end of the prior month. "eY" is the cumulative sum of all Petroleum Expenses incurred by the Contractor from inception to the end of the prior month. "n" is the index number of the relevant month Based on R-factor, the Profit Splits to Government of Malawi are: R-factor 0-1: 20% R-factor 1-2: 22.4% R-factor 2-3: 24.8% R-factor 3-4: 27.2%
Corporate Income Tax Rate	30% Capex Depreciation 5 years 25% (reduction)	There is no exemption for the oil industry. Depreciation for CIT is assumed the same as for cost recovery, subject to confirmation. Article 30.10 states that the government agrees to negotiate, in good faith, a reduction to the rate of corporate income tax at the contractor's request made at any time at least two years following the signing of the contract. The full implications of this provision are unclear. We have evaluated reductions of 2%, 5% and 10% in the rate of corporate tax in the analysis above.

State Participation	10%	State participation is allowed up to 10%. The state party is carried for all costs, up to the start of production, by the non-state party. The costs of the carry, without interest, are recovered by the non-government party from Cost Oil.
Inflation Rate	0%	Inflation is not included for modelling purposes.

Fiscal Terms for Proposed Addendum

Fiscal Terms-Proposed Addendum		
PSA Terms	Negotiation 18th November 2016 Terms as stated by an official from Ministry of Mining at MWEITI Meeting, 13 February 2017.	Royalty: 10% Cost Recovery Limit: 70% Development Depreciation for Cost Recovery: 20% per annum starting year of spend or 1st Production (whichever the latter) Profit Splits to Government of Malawi: Production 0 to 12,499 bpd: 20% Production 12,500 to 24,999 bpd: 22.5% Production 25,000 to 49,999 bpd: 25% Production 50,000 to 99,999 bpd: 27.5% Production 100,0000 to 149,999 bpd: 30.0% Production above 150,000 bpd: 35%
Corporate Income Tax Rate	30% Capex Depreciation 5 years	There is no exemption for the oil industry. Depreciation for CIT is assumed the same as for cost recovery, subject to confirmation.
State Participation	20%	State participation is allowed up to 20%. The state party is carried for all costs up to the start of production by the non-state party. The costs of the carry without interest are recovered by the non-government party from Cost Oil.

Inflation Rate	0%	Inflation is not included for modelling purposes.

Fiscal Terms from Model PSA

Fiscal Terms-Model PSA		
PSA Terms	Malawi Model PSA March 2014	Royalty: Onshore and Shallow Water Fields 12.5% Royalty: Deep Water Fields 10% Cost Recovery Limit: 60% Development Depreciation for Cost Recovery: 20% per annum starting year of spend or 1st Production (whichever the latter) Profit Splits to Government of Malawi: R-factor (n+1) = eX / eY Where: "eX" is the cumulative sum of all contract revenues earned by the Contractor either from Cost Recovery or Profit Oil from inception to the end of the prior month. "eY" is the cumulative sum of all Petroleum Expenses incurred by the Contractor from inception to the end of the prior month. "n" is the index number of the relevant month Based on R-factor, the Profit Splits to Government of Malawi are: R-factor <1: 30% R-factor 1-2.5: 50% R-factor >2: 70%
Corporate Income Tax Rate	30% Capex Depreciation 5 years	There is no exemption for the oil industry. Depreciation for CIT is assumed the same as for cost recovery.
State Participation	10%	State participation is allowed up to 10%. The state party is carried for all costs up to the start

		of production by the non-state party. The costs of the carry without interest are recovered by the non-government party from Cost Oil.
Financing	-	Recovery of the interest on development financing not allowed in draft model PSA.
Inflation Rate	0%	Inflation is not included for modelling purposes.

ANNEX 2: PROJECT CONSULTATIONS

In order to ensure input from relevant stakeholders, consultations were undertaken in Lilongwe on 14-16 February 2018. We would like to thank the following individuals for participating.

MWEITI/GIZ
Mr. George Harawa (Coordinator)
Mr. Keith Matanda (Communications Officer)
Mr. Abdul Chiwalo (Accountant)
Mr. Vitima Mkandawire (GIZ-TA)

REVENUE POLICY DIVISION - MINISTRY OF FINANCE
Mr. Grecium Kandio (Deputy Director of Tax Policy)
Mrs. Catherine Chilima (Deputy Director for Non Tax Policy)

DEPARTMENTS OF MINES AND GEOLOGICAL SURVEY
Mr. Denson Makwela (Deputy Director - GSD)
Mr. Cassius Chiwambo (Head of Oil and Gas Unit - DOM)
Mr. Barnett Msika (Chief Mining Engineer)
Mr. Tikondane Phiri (Chief Mining Engineer)
Mr. Moses Kachemwe (Geochemist)
Mr. Ishaqua Milazi (Engineer - Oil and Gas)

CHAMBER OF MINES
Mr. Grain Malunga

ACTION AID
Mr. Peter Pangani

ENDNOTES

1 Resource Contracts, http://www.resourcecontracts.org/countries/mw.
2 The government was able to draw on significant international support from the Commonwealth Secretariat, the International Monetary Fund (IMF), the African Legal Support Fund, the University of Dundee, and the International Senior Lawyers Project.
3 Don Hubert, 'Malawis Troubled Oil Sector: Licenses, Contracts and their Implications, Oxfam Malawi, 2017.
4 The model PSA appears to contain an error here with the second tranche being R 1-2.5 and the third tranche being greater than 2 (rather than 2.5). We have modeled the tranches as written in this table.
5 Don Hubert, Many Ways to Lose a Billion: How Governments Fail to Secure a Fair Share of their Natural Resource Wealth, Publish What You Pay – Canada, 2017, p. 41-43. The interest on debt financing also has a potential impact on the calculation of taxable income and therefore on government revenue from corporate income tax as noted below.
6 See Model PSA, March 2014, Definitions 1.1, p.6.
7 See Tullow Oil, Written Submission to Ugandan Parliament, 11 April 2012, p. 10-12.
8 See Tullow Oil, Written Submission to Ugandan Parliament, 11 April 2012, p. 10-12.
9 Cost estimates adapted from Uganda data as set out in Colin Ward and Artem Malov, Evaluating Uganda's Oil Sector: Estimation of Upstream Projects, KAPSARC, 2016.
10 Early Oil from Turkana Marginal Benefits / Unacknowledged Costs, KCSPOG, 2016.
11 Deepwater drilling costs adapted from US Gulf of Mexico. See Trends in U.S. Oil and Natural Gas Upstream Costs, Energy Information Agency, March 2016.
12 It is likely there will be a cost uplift factor from global deepwater industry cost levels for working in a lake in mid-continent similar to the Caspian Sea. These additional costs are difficult to estimate and have therefore not been factored into the outline $/bbl costs used in this analysis.
13 New York Mercantile Exchange (NYMEX) CME Group Brent Futures prices (dated December 2025), 19 January 2018, is $59.46/bbl, rounded up to $60/bbl.
14 For Uganda, see the Model Production Sharing Agreement of 2016. For Kenya, see the draft Model Production Sharing Contract of 2015.
15 "A suitable tax structure and a target range of AETRs result from this analysis. These simulations, and those of other sources, suggest reasonably achievable ranges of discounted AETRs will be 40–60 percent for mining and 65–85 percent for petroleum." Fiscal Regimes for Extractive Industries: Design and Implementation, IMF 2012, p. 29.
16 Uganda: Technical Assistance ReportImplementing Fiscal Regimes For Extractive Industries, IMF Country Report No. 17/368, 2017, p. 20. Also A Good Deal Better, Global Witness, 2014, and East African Fiscal Regime Comparison, Palantir, 2014.
17 See Silvana Tordo, Fiscal Systems for Hydrocarbons, World Bank, 2007, p. 20.
18 See Daniel Johnston, International Petroleum Fiscal Systems Data Base, PennWell, 2001.

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Oxfam in Malawi
Green Heritage Building
City Centre Area 13
Private Bag B331, Lilongwe Tel:
00265 1770 489/525/563 Email:
infomalawi@oxfam.org.uk
Oxfam in Malawi
Oxfam in Malawi