



# Competitiveness of Ghana's Upstream Petroleum Fiscal Regime: Fit for Purpose?

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## 1 INTRODUCTION

One of the overarching objectives of most natural resource-rich countries is to get a fair share of the revenues accruing from the exploration and exploitation of such natural resources in their respective countries. This is because host governments are presumed to be holding these

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natural resources in trust for their citizens. Thus, any policy to collect these revenues must be formulated bearing in mind the best interest of its citizenry. However, whether or not this objective can be achieved depends very much on the fiscal regime that governs the distribution of this wealth accrued from exploiting the natural resource endowments and how effective it is in capturing maximum economic rent to the State. In the extraction of petroleum resources, the framework for sharing the economic rent and its benefits between the home country and investors is critical. Unfair regimes that distribute risks and rewards inequitably can precipitate contract renegotiation and resource nationalisation.

The fiscal regime governs the relationship between the host government and investors. This risk-reward balance is anchored on the twin goals of investment attraction and revenue maximisation. According to Nakhle (2010), the design of fiscal regimes is a critical factor in shaping perceptions of an oil and gas basin's competitiveness. Exploration and development activities require a balancing act between the respective interests of the producing countries and the oil companies. A trade-off is bound to exist since both government and oil companies seek to maximise their rewards. This can be achieved by designing a competitive fiscal regime, which considers different stakeholders' interests and is attractive to investors compared to opportunities in other countries. Moreover, evaluation and comparison of fiscal terms are crucial and provide a basis for IOC's overseas investment decision while contributing to the most active implementation of upstream oil and gas E&P business (Abdo, 2014; Boykett et al., 2012; Tordo, 2007). If the terms are too strict, the incentives to the oil companies to invest in exploration, development and production can be severely damaged because investment flows to countries offering a more attractive fiscal regime.

Since the early 2000s, the world's major deep offshore regions, including the Gulf of Guinea (West Africa), Gulf of Mexico (GoM), Guyana-Suriname and Brazil, have witnessed a flurry of exploration and development activities. Rising oil demand, declining shallow water and onshore reserves, political instability in big onshore areas, and high oil prices have fuelled these ongoing deepwater activities. However, deep-water exploration, such as what pertains to Ghana, requires sophisticated technology and large capital expenditures. Likewise, the investment risks are considerably higher than with traditional onshore exploration activity. Thus, only large international oil companies (IOCs) or independents with the financial muscle, are often the ones undertaking these frontier deep-water activities. In evaluating the business decision to invest in a country,

investors typically consider macroeconomic and political factors, geology and fiscal terms, making it imperative for governments to design unique fiscal systems to attract investments. Although current relatively high oil prices make the economics of exploration and development in most regions favourable, the true test of the long-term effectiveness of a fiscal regime is its flexibility to capture value from historically volatile oil and gas prices, and fluctuating costs which could adversely impact investment outcomes.

Crude oil production has provided a critical boost to Ghana's economy over the past ten years. It is set to form a fundamental component of the country's industrial strategy and transition towards an upper-middle-income country, acting as the lever to provide jobs and energy security. The rapid growth of the upstream oil and gas industry in Ghana, like many other petroleum-producing countries, has been dependent on external foreign direct investments led by IOCs and their partners with limited direct state participation, particularly in the exploration phase. In this vein, Ghana in its quest to attract investors into the country's upstream petroleum sector enacted several policy changes, including fiscal ones. These policy changes were particularly geared towards increasing the government's take following the de-risking of the basin with the Jubilee Field discovery in 2007. Some of these changes included revisions to Ghana's thin capitalisation rules, increased oil and gas royalties, and other non-tax policies. These are also reflected in various international rankings of the overall oil and gas policy environment and specifically the fiscal environment. For example, both the 2017 and 2021 Resource Governance Index (RGI) published by the Natural Resource Governance Institute puts Ghana's tax regime as being "good" with 80 out of 100 points under the value realisation sub-component of the RGI (NRGI, 2017, 2021). Likewise, Canada's Fraser Institute's 2017 Global Petroleum Survey, which directly seeks the opinions of senior oil company executives and decision-makers, ranked Ghana at 41 out of 97 countries on its fiscal terms being a deterrent to investment (Stedman and Green, 2017).

Since 2010, Ghana has produced 453.89 million barrels of crude oil from three existing fields: Jubilee from December 2010,<sup>1</sup> Tweneboa

<sup>1</sup> Tullow Oil. (n.d.). Jubilee field. Available at: <https://www.tulloil.com/our-operations/africa/ghana/jubilee-field> (Accessed: 31 July 2021).

Enyenra Ntomme (TEN) from in August 2016<sup>2</sup> and Sankofa Gye-Nyame (SGN) from July 2017<sup>3</sup> (PIAC, 2020). A total of 452.09 million barrels have been lifted (sold) by all partners out of the 453.89 million barrels produced as at the end of 2020 (PIAC, 2020). Of the 452.09 million barrels lifted, Ghana’s share has been 78.85 million barrels—this is 17.44% of the total barrels lifted. Ghana’s share comprises mostly royalties, carried and participating interest (CAPI), corporate income tax (CIT) and to a lesser extent, surface rentals. In terms of value, we assess that US\$31.62 billion has been generated from the sale of all the liftings since 2010, using yearly average achieved crude prices, which is very close to Brent prices—all of Ghana’s crude oil trade at close parity to Brent crude, so this is a reasonable assumption based on norm traded values. The estimated proceeds from liftings by Ghana Group is US\$6.55 billion (20.71% of the total value generated). This is close to its 17.44% production share. On the other hand, the cumulative investments made into all three fields for exploration and development are estimated to be about US\$19 billion (Oppong and Kwame Amoni, 2021). This comprises US\$8.8 billion invested in the Jubilee field, US\$5 billion in the TEN field and another US\$5.2 billion in the SGN field (Oppong and Kwame Amoni, 2021).

The foregoing raises interesting questions: Are Ghana’s petroleum fiscal (tax) terms generating enough rents for the State after ten years of production? Or does this reflect the state of play with the contracts signed at the time? How do we ensure that the State gets its “fair share” going forward, but also considering the following: (1) de-risking of the basin; (2) the need to attract both domestic and foreign investments into the sector; (3) energy transition imperatives which makes the “advantaged barrels” concept even more poignant—that is, countries with higher marginal production costs are maybe unlikely to extract their oil as they would be at the higher end of the cost curve?

Against this background, this chapter analyses the attractiveness of Ghana’s fiscal regimes and attempts to answer the fundamental question of whether the regime is fit for purpose after ten years of oil and gas

<sup>2</sup> Tullow Oil. (n.d.). TEN field. Available at: <https://www.tulloil.com/our-operations/africa/ghana/ten-field> (Accessed: 31 July 2021).

<sup>3</sup> Kpodo, K., 2017. ENI pumps first oil from Ghana’s Sankofa field. Available at: <https://www.reuters.com/article/us-ghana-oil-idUSKBN19R1R9> (Accessed: 31 July 2021).

production in the country. It begins by discussing fiscal regimes more broadly, including evaluation criteria. This is followed by a discussion of Ghana's fiscal frameworks and an analysis of their attractiveness. The latter is based on detailed economic cash flow modelling. We construct various cash flow models to assess the fiscal attractiveness of Ghana's contracts. Four fiscal appraisal criteria are utilised for this evaluation: profitability, risk sharing, neutrality and progressiveness. We then discuss Ghana's fiscal competitiveness and conclude with some recommendations on strengthening the fiscal regime for the future.

## 2 PETROLEUM FISCAL REGIMES AND INVESTMENT

### 2.1 *Economic Rents and Extractives Taxation*

As is widely established in the literature, natural resource ventures have some peculiar attributes which need to be considered in the design of optimal tax policies. These include the following:

- Wide range of technical, commercial, fiscal and political risks throughout the supply chain.
- Large up-front capital requirements leading to high sunk costs.
- Long lead times between initial investment and first revenues generated—long payback period.
- Long production periods—long contracts and licences.
- Geological uncertainty—exploration is a speculative activity fraught with many failures.
- Asymmetric information—private investors often better informed than host governments on technical and commercial aspects of a project, especially in the early stages.
- Extensive involvement of multinationals: complex tax issues, unique cost sharing and financing arrangements, sensitivities on sharing the benefits from national resources.
- Exhaustibility: non-renewable natural resources; valuable asset in the ground that can be exploited only once; opportunity cost of extraction includes future extraction forgone.
- Environmental concerns—climate change, CO<sub>2</sub> emissions, destruction to land, wastes, pollutants.

For example, regarding commercial risks, the extant literature shows that crude oil prices react to a variety of geopolitical and economic events. As the US EIA (2021) notes, oil prices have responded to geopolitical and

other events over the past 40 years. Any event that can disrupt supply or increase uncertainty about future oil supplies tends to drive up prices. What this means is that it is almost impossible to provide any certain long-term forecast of oil prices; even future market developments are fraught with significant uncertainties. For example, Wachtmeister et al. (2018) show that there is widespread uncertainty in many current oil price projections with mean absolute percentage error for oil prices in the range of 17, 37 and 67% on 1-, 5- and 8- year horizons, respectively.

An implication of these special features of natural resources and the extractives industry is that a special fiscal (tax) treatment needs to be put in place. That is, there is a need for elaborate fiscal arrangements to capture various features of the industry, which means we can utilise several instruments. However, there is an imperative to consider headline tax rates (marginal rates) versus the interaction of different instruments (effective tax rate). There is also the importance of not just the tax rates but also the timing of when various fiscal instruments hit investors—that is, profit related versus progressive taxes. Finally, there is a need to consider the array of commercial and regulatory obligations placed on investors, which, although in most circumstances not labelled as taxes, are in effect just that, in terms of their economic consequences.

To capture these dynamics, the generally accepted concept of economic rents is used. There are a variety of definitions for economic rent. In general, they are based on a modified Ricardian view which defines economic rent as “*the income received by the owner of a factor of production over and above the amount required to induce that owner to offer the factor for use*” (Parkin, 2015: p. 402). That is, economic rent is equal to the marginal product (benefit received) less the opportunity cost (cost of employing more factors of production) (Shobande et al., 2020; Abdo, 2014; Mintz and Chen, 2012; Kemp and Stephens, 1996). In the petroleum industry, economic rents are quite common and occur for several reasons, including reflecting the scarcity value of the non-renewable resource and monopoly rights as shown in Fig. 1 (da Cunha et al., 2020; Robinson, 2017; Long and Kemp, 2014; Hotelling, 1931). From Fig. 1, for a given long-term price of oil, say  $P$ , different oil fields will seek to supply the market at their respective incremental marginal costs of production, development and finding. The blue area represents the economic rent, which, in theory, could be taxed away by the owner of the oil resources without deterring investment or reducing output as they

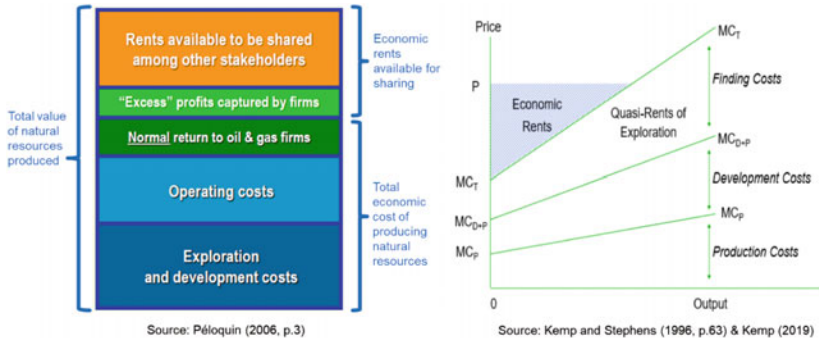


Fig. 1 Economic rent concepts

have recovered all their costs including a normal return and sometimes excess profits (Kemp, 2019; Watkins, 2001; Kemp and Stephens, 1996).

Fiscal regime implications of economic rent concept are as follows: Firstly, the State, as resource owner, should get a fair share, although what is fair is often the subject of debate (Cameron and Stanley, 2017; Amoako-Tuffour and Owusu-Ayim, 2010). For example, Ghana's 2010 petroleum policy stated that "the fiscal regime is designed to ensure the right balance between national developmental needs and agenda and investor needs". Secondly, the fiscal regime should ideally provide the State with revenue streams in all production periods while having an increased share of revenues as profitability increases (progressivity). Thirdly, the fiscal regime should be attractive enough to encourage investments, both in the now and in the long run, in the sense that these terms must be robust in the face of changing circumstances.

## 2.2 What Constitutes an Attractive Petroleum Fiscal Regime?

Underpinning the fiscal regime and by extension, durable extractives contracts, is often the principle of fair sharing of the economic rents generated from petroleum resource extraction between host governments and private investors. Thus, the fiscal system should be consistent with "the government's overall economic and fiscal objectives and provide a fair sharing of financial benefits between the investor and the host government" (OECD, 2019, p. 3). The optimal mix of fiscal instruments and terms should take into consideration risk-reward balance and country

circumstances such as new entrant or basin maturity (Acheampong et al., 2021; Acheampong, 2020; OECD, 2019; Nakhle, 2008, 2010; Tordo, 2007; Iledare, 2004). Different methods are applied in the evaluation of petroleum taxation regime, using several factors including profitability, neutrality, progressiveness (flexibility), among others. These are briefly discussed in Table 1.

**Table 1** Efficiency criteria of fiscal regimes

<i>Concept</i>	<i>Brief explanation</i>
Neutrality and non-distortionary taxation	A neutral fiscal regime avoids distorting investment incentives and decisions; that is, it should not encourage over-investment nor deter those investments from otherwise taking place in the first place. In other words, the pre-tax ranking of investment outcomes should not be any different from its post-tax ranking or divert investments from the industry all together. Sometimes, projects that are viable, pre-tax, can become unprofitable following the application of the fiscal instruments, creating efficiency losses
Progressiveness (flexibility)	Generally speaking, progressive fiscal regimes are those which are designed to collect a higher share of the rents, the higher the rents become, for example, either from rising oil prices or lower costs. Therefore, the State receives a rising share of the cash flows as the intrinsic profitability of the project increases, due to changes in future market conditions. Progressive schemes tend to be more equitable and less distorting although they can lead to “gold plating” if no checks are put in place. Regressive schemes, on the other hand, collect a higher share of the rents the lower these rents become. In terms of its assessment, progressivity is measured through the variation in project NPV
Risk sharing	The underlying fiscal regime and instruments must have enough assurances to recover investment costs (cost recovery mechanisms), especially during the exploration and production phases, but this can risk revenue delays for host governments. Often, governments, especially in newfound petroleum-producing countries, tend to prefer early and dependable revenues especially at the very beginning of E&P activities
Tax administration (simplicity and compliance)	The underlying fiscal regime and instruments on which they are premised, should be simple to administer by the revenue authorities and for investors to comply with. Thus, the fiscal regime should reduce information asymmetry and compliance costs between investors and the host government. In terms of administrative efficiency, the petroleum tax regime must be easily understood by investors to encourage compliance

(continued)



**Table 1** (continued)

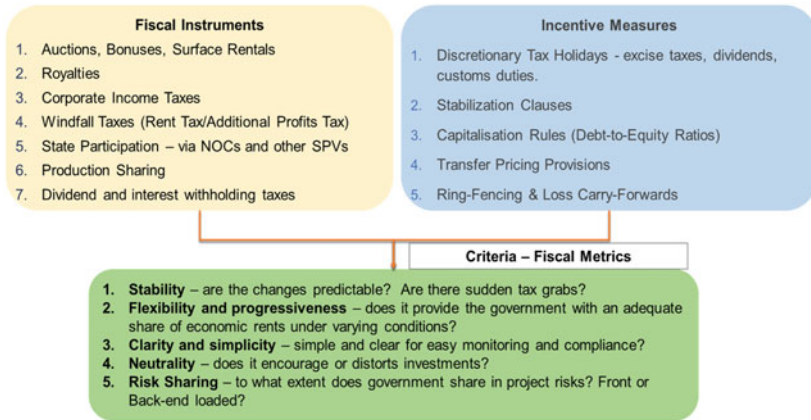
<i>Concept</i>	<i>Brief explanation</i>
Stability and international competitiveness	Fiscal regimes must be competitive with those of other countries within the region and further out. This is because countries compete with each other to attract petrodollar investments, often from a similar cohort of investors—the “neighbourhood effect”. In this regard, issues of stability of the regime also become important; the fiscal regime must be less susceptible to sudden or abrupt changes or such changes must be fairly predictable. Most countries tend to offer mostly a mix of “freezing clauses” which keep contractual and/or fiscal terms unchanged for a certain period of time or “equilibrium clauses” that allow for adjustments of the contractual terms depending on a range of factors such as change in economic conditions. Finally, tax rules for the petroleum industry must be codified in law to ensure transparency and equity

*Source* Author’s depiction based on Nakhle and Acheampong (2020), Banda (2019), Manaf et al. (2016), Jarmuzek et al. (2016), Mansour and Nakhle (2016), Agalliu (2011), Nakhle (2010), Amoako-Tuffour and Ayim (2010), Goldsworthy and Zakharova (2010), and Tordo (2007)

There are primarily three different approaches to fixing fiscal terms. Firstly, through detailed content whereby a comprehensive legislation or regulation provides for most of the fiscal provisions required for the conduct of sector operations. This approach is often used in the more developed countries, which have extensive sector and legislative experience. Secondly, this could be fixed through individually legislated contracts whereby the most important terms are contained in individually negotiated agreements. This used to be the case in several developing countries with newfound petroleum resources that did not have a dedicated or overarching petroleum law in place.

A third dimension is the hybrid scheme—which is more popular these days—which combines a brief petroleum law with detailed secondary regulations and individual stipulated clauses in the contracts. In general, the preference by international investors is for inclusion of fiscal terms in hydrocarbon legislation. This is to reduce administrative costs, political difficulties and investors’ perceived risk and increase transparency. As the IMF notes “*the alternative of setting the fiscal terms out in a model agreement can make them little more than a basis for negotiation*” (IMF, 2012, p. 36).

Ghana’s upstream fiscal regime falls under the third category and is governed by the following legislation:



**Fig. 2** Interaction of fiscal instruments, incentive measures and fiscal metrics (*Source* Authors' depiction)

- Petroleum Exploration & Production Act, 1984 (PNDCL 84)—for the pre-Jubilee contracts
- Petroleum Income Tax Act, 1987 (PNDCL 188), up to and including the year 2015
- Income Tax Act, 2015 (Act 896)<sup>4</sup>
- Petroleum (Exploration and Production) Act, 2016 (Act 919)<sup>5</sup>
- Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359)<sup>6</sup> as amended by the Petroleum (Exploration and Production) (General) (Amendment) Regulations, 2019 (L.I. 2390)
- Model Petroleum Agreement (MPA).

Figure 2 lists the main fiscal instruments as well as incentive measures and fiscal metrics used to collect and assess fiscal terms. The main fiscal instruments include auctions, bonuses, surface rentals, royalties; corporate income taxes; windfall taxes (rent tax/additional profits tax); state participation through the national oil company (NOC) or other special purpose vehicles (SPVs); and production sharing, among other indirect taxes.

<sup>4</sup> See Sections 63–76 titled “Division I: Petroleum operations”.

<sup>5</sup> See Sections 85–89 titled “Fiscal Provisions”.

<sup>6</sup> See Sections 71–78 titled “Fiscal Provisions”.

Incentive measures on the other hand include discretionary tax holidays such as relief from paying customs duties, stabilisation and transfer pricing provisions, among others. Finally, the interaction of the fiscal instruments and incentive measures is assessed using fiscal metrics such as flexibility and progressiveness, stability, clarity and simplicity and neutrality.

### 3 STRUCTURE AND EVOLUTION OF GHANA'S FISCAL REGIME

Tables 2, 3 and 4 show the fiscal instruments available for collecting petroleum revenues in Ghana's upstream oil and gas industry. Following Agalliu et al. (2011), we classify the revenue risk of the fiscal instruments in the following order: (1) low risk to government—bonus payments, royalties; (2) medium risk to government—corporate income taxes, profit sharing; (3) high risk to government—equity participation. This risk classification is tested later in our economic modelling in Sect. 4. Also, while the State has to balance the effect of freezing stabilisation clauses contained in earlier agreements with the demands of the IOCs, it has been making strenuous efforts to assert more control of the industry for the benefit of its citizens thereof. This is manifested in myriad ways such as the transition from a combination of freezing and economic equilibrium clauses, to exclusively, the use of economic equilibrium stabilisation clauses (Stephens & Dowuona-Hammond, 2019). The duration of petroleum agreements has also been reduced from thirty (30) to twenty-five (25) years, which provides more control to the State, and there have been much more aggressive local content provisions in Ghana's legislation, to provide more benefit and control to citizens and the State.

### 4 ECONOMIC ANALYSIS OF GHANA'S UPSTREAM FISCAL TERMS

#### 4.1 *Modelling Framework and Assumptions*

The fiscal model used in this analysis is an adapted version of the IMF's fiscal analysis of resource industries (FARI) model (Luca and Puyo, 2016). The FARI approach allows us to conduct project-level modelling to estimate the government's share of the economic rents of a resource project. The economic rent is the discounted total pre-tax net cash flows (Luca

**Table 2** Sources of revenue in Ghana's petroleum contracts

<i>Fiscal instrument</i>	<i>Commentary</i>
Signature bonus	This instrument did not exist before 2016 and as such cannot be found in any of the contracts before then. Signature bonuses were only introduced with the passage of the Petroleum (Exploration and Production) Act 2016 (Act 919) and Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359). They were implemented for the first time in 2018 with the launch of Ghana's first competitive licensing round. However, the Ghana government opted for the amount of the signature bonus to be fixed in the 2018 licensing round but could have also allowed it to be competitively bid by prospective contractors as per Section 74(2) of L.I. 2359
Production bonus	This instrument did not also exist before 2016 and as such cannot be found in any of the contracts before then. Production bonuses were also introduced with the passage of Act 919 and L.I. 2359. It is payable on the first anniversary of commencement of petroleum production. Again, the Minister of Energy can specify the amount or allow for competitive bidding of the production bonus. During Ghana's maiden licensing round, no provision was made for production bonuses nor an explanation given for its omission in the fiscal criteria although the Minister of Energy can make this a requirement as per Section 74(1b) of L.I. 2359
Royalty	These are imposed on the value of output, in respect of gross volume of petroleum produced and saved ( <i>ad valorem</i> royalty). In the Ghanaian context, royalties have ranged between 5% and 12.5% of total gross production for oil and 5–10% for gas, depending on the specific petroleum agreement (see Tables 3 and 4). These royalties are delivered to the Republic in kind but can also be in cash. GNPC, the national oil company, in carrying out petroleum activities is also subject to the payment of royalty as may be prescribed. In Ghana's contracts signed from 2004 to 2018, royalties were negotiated between the State and Contractor. However, as part of the move to use market-based instruments, royalties are now biddable fiscal items and are specified in petroleum tender documents or indicated in relevant direct negotiation documentation <sup>7</sup>
Carried (initial) interest	This is the State's interest held by GNPC, the national oil company, pursuant to all petroleum agreements in respect of which the contractor or international oil company (IOC) pays for the conduct of petroleum operations without any entitlement to reimbursement from the State. In essence, Ghana does not incur costs during exploration and development, as the GNPC does not pay anything when it comes to costs incurred during exploration and development, but pays its equity share on commencement of production. The State, through GNPC thus, pays for its share of the costs when oil production starts. Petroleum agreements that existed prior to the enactment of the Petroleum Act of 2016 had a minimum of 10% carried interest to the State. This has been increased to a minimum of 15% carried interest under the 2016 Petroleum Act (see Tables 3 and 4)

<sup>7</sup> See Section 71(1) of Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359).

<i>Fiscal instrument</i>	<i>Commentary</i>
Additional interest	The State, through GNPC, has the option in respect of each development and production area (DPA), to acquire an additional interest of up to a defined percentage for which GNPC contributes a corresponding proportionate share to all the development and production costs incurred from the date of commercial discovery, in respect of such DPA. Based on current petroleum agreements, additional interest has an upper ceiling of 25% although most of the pre-Jubilee contracts have had 2–5% additional interest.
Petroleum (corporate) income tax	This is a tax on the profits of oil and gas companies. The Petroleum Income Tax Act stipulates a tax rate of 50% but also provides that a petroleum agreement can provide for some other rate. Because of the provision that allows the State to vary the stipulated 50% rate, all existing petroleum agreements have an effective corporate income tax (CIT) rate of 35%. This is a single-rate structure, levied at corporate basis (not field level) and also on profit and not gross revenue. This rate has been incorporated in the Income Tax Act, 2015 (Act 896) since 2016. In addition to cost deductions, interest expenses and losses carried forward for five years are allowed in computation of tax base (see Tables 3 and 4). Decommissioning costs, which is a shared obligation among partners, are also deductible for both estimating income tax and additional oil entitlement (AOE).
Additional oil entitlement (AOE)	To capture the economic rent, governments impose a special petroleum tax—a windfall or resource rent tax (RRT), which is not paid before a project reaches payback and achieves a certain rate of return. The windfall tax is levied on a project or a field's cash flows, whereas the CIT is on a company's profit. Also, for the windfall tax, interest expenses are usually not permitted as a deduction, while capital costs are expensed or secure immediate relief. The AOE is Ghana's version of windfall tax scheme in the upstream oil and gas sector and is applied from each development and production area. It is charged on contractor's share of petroleum produced from each field on the basis of the after-tax inflation-adjusted rate of return (RoR) that the contractor achieved with respect to each field. <sup>8</sup> The Contractor's RoR is calculated based on its net cash flow (NCF) and is determined separately for each development and production area at the end of each period (usually monthly, quarterly or annually). Ghana's petroleum agreements provide three to five RoR thresholds with corresponding additional profits tax rates varying between 5% to 30% (see Tables 3 and 4).

(continued)

<sup>8</sup> See Nakhle, C., and Acheampong, T., 2017. "Comparative assessment of oil and gas windfall taxation in Ghana". Ghana Oil and Gas for Inclusive Growth (GOGIG).

**Table 2** (continued)

<i>Fiscal instrument</i>	<i>Commentary</i>
Surface rentals	Surface rentals are annual rents paid by the IOCs and GNPC to the State for leasing the surface of the sea or land to explore for oil and gas resources. Surface rentals are paid in dollars per square kilometre of acreage operated by the licensees of the area (see Tables 3 and 4)
Training allowance	Provisions are made for training as part of the local content criteria although this is a one-time payment of a minimum amount. Additional provisions are made for the transfer of knowledge and skills as part of the local content criteria, although this is set as a one-time payment of a minimum amount by the Contractor to the Government
<i>Incentive measures</i>	
Thin capitalisation & ring-fencing provisions	Permitted debt-to-equity ratio for tax purposes is 3:1 (or 75% debt to equity) under the Income Tax Act, 2015 (Act 896). Also, petroleum costs for exploration, development and production operations are ring-fenced, that is separately identified for each development and production area. Additionally, profits from one project cannot be used to offset the losses of another project unless both projects are of the same type or in one contract/licence area
Loss carry forward	Losses could be carried forward for an unlimited period under P. N. D. C. L. 188, however, under Act 896, losses can be carried forward for five years. <sup>9</sup> There is thus a sunset clause to the period of enjoying loss carry forward. Ghana does not have an extra relief for capital expenditure—normally called uplift—which is an incentive to encourage investment for marginal projects
Capital allowances (tax depreciation)	This is deductible, non-cash expense for income tax purposes. Ghana applies a 20% five-year straight-line deduction for exploration, appraisal and development costs and other capital expenditures starting from first production. Thus, 20% of the value of these costs are allowed as a deduction from profit before tax is paid on the chargeable income arrived at after the deduction

<sup>9</sup> See Section 17 of Income Tax Act, 2015 (Act 896); and regulation 19 of Income Tax Regulations, 2016 (L.I. 2244).

Capital gains tax

Upstream assets are continually bought and sold among industry players, but some governments impose a tax on such assignments in the sector. This is applied when an IOC sells its petroleum assets and realises a profit. The tax is charged on that profit. There have been recent debates on capital gains taxation on asset sales in Ghana (and in other African countries) with the Government and civil society groups asking some IOCs to pay capital gains taxes as a pre-condition for the sale of their assets and exit from the country.<sup>10</sup> On the other hand, the IOCs argue that the fiscal stabilisation provisions in their petroleum contracts prevent them from paying capital gains taxes.<sup>11</sup> Well-known cases in Ghana include the proposed sale<sup>12</sup> of Kosmos Energy's stake in the Jubilee field to ExxonMobil in 2009–2010; EO Group's sale<sup>13</sup> of its shares in the Jubilee Field to Tullow Oil Ghana in 2011; Aker Energy's farm-in agreement<sup>14</sup> into Hess' stake in ultra-deepwater Tano

(continued)

<sup>10</sup> See Myers, K., 2010. Selling oil assets in Uganda and Ghana—A taxing problem. *Revenue Watch Institute Release, New York, 16*.

<sup>11</sup> See Mansour, M. and Nakhle, C. (2016). Fiscal stabilization in oil and gas contracts—evidence and implications. Oxford Institute for Energy Studies. OIES PAPER: SP 37.

<sup>12</sup> Africa Confidential., 2010. The politics of no. Available at: [https://www.africa-confidential.com/article-preview/id/3638/The\\_politics\\_of\\_no](https://www.africa-confidential.com/article-preview/id/3638/The_politics_of_no) (Accessed: 6 May 2021).

<sup>13</sup> ModernGhana.Com., 2011. As Tullow Acquires EO Group Shares GRA Moves To Tax Deal...And Edusi, Owusu Smile all the Way to the Bank Available at: <https://www.modernghana.com/news/342245/as-tullow-acquires-eo-group-shares-gra-moves-to.html> (Accessed: 6 May 2021).

<sup>14</sup> Skonmord, O., 2021. Aker Energy buys Hess Ghana business, expects first oil in 2021, U.S.. Available at: <https://www.reuters.com/article/us-hess-divestiture-aker-idUSKCNIG300A> (Accessed: 6 May 2021).

Table 2 (continued)

<i>Incentive measures</i>	<i>Commentary</i>
Withholding taxes	<p>Cape Three Points block in 2018; and most recently Anadarko's stalled (acquired by Occidental Petroleum) asset sale<sup>15</sup> to Total Africa. In the case of the Occidental Petroleum sale, the Ghanaian authorities raised two sets of fiscal claims regarding the change of ownership of these blocks in the context of the disposal of Anadarko's African assets: one relates to Anadarko's past operations in Ghana and the other relates to USD500 million capital gain claims on the transfer of assets to Oxy and Total. Gains from the assignment or other disposal of an interest in the petroleum right with respect to which the operation is conducted is now taxable.<sup>16</sup> This can, however, not be applied retrospectively.</p> <p>Withholding tax is an amount of tax that an authorised agent of the Commissioner-General of the Ghana Revenue Authority (GRA) is mandated to withhold at source from payment for goods, works or services to resident or non-resident persons as required by law. In the case of oil and gas, the withholding tax is on works or service. The withholding tax rate on dividends and interest is set at 8%. However, some Contractors are still subject to the provisions of withholding taxes under the Internal Revenue Act 592 (Act 2000) and Petroleum Income Tax Law 188 of 1987 even though they have been repealed. This is because the Contractors' underlying petroleum agreements were signed under those Acts and the said agreements contain freezing stabilisation clauses.<sup>17</sup></p>

<sup>15</sup> Donto, E., 2020. Total-Occidental's Ghana deal delayed by \$500m tax claim. Available at: <https://www.worldoil.com/news/2020/3/2/total-occidental-s-ghana-deal-delayed-by-500m-tax-claim> (Accessed: 6 May 2021).

<sup>16</sup> See Section 66(1)(d) of Income Tax Act, 2015 (Act 896).

<sup>17</sup> Stephens, T. K., & Dowuona-Hammond, C., 2019. From total immunization to an economic balancing act: The trajectory of stabilization clauses in Ghana's petroleum agreements. *Oil, Gas & Energy Law Journal (OGEL)*, 17(2).



Table 3 Evolution of fiscal terms (2004–2006)

BLOCK	West Cape Three Points	Deepwater Tano	Jubilee Unithised (DWT_WCTP)	Deepwater Tano	Deepwater Tano	Deepwater Tano	Offshore Cape Three Points
DENOMINATION	WCTP	DWT	JUBILEE UNITHISED	TEN	HESS	OCTP	
<b>OPERATOR</b>	Tullow Oil	Tullow Oil	Tullow Oil	Tullow Oil	Hess	Eni	
<b>EQUITY PARTNERS</b>	Tullow (operator) 25.66%; Kosmos 30.02%; Anadarko 30.02%; GNPC 12.50%; Petro SA 1.80%	Tullow 47.18%; Anadarko – 17.00%; Kosmos – 17.00%; GNPC -15%; PetroSA -3.83%	Tullow (operator) 35.48%; Kosmos 24.08%; Anadarko 24.08%; GNPC 13.64%; Petro SA 2.73%	Tullow (operator) 47.18%; Kosmos 17.0%; Anadarko 17.0%; GNPC 15.0%; Petro SA 3.82%	Hess (40%), Lukoil (38%), GNPC (20%), Fueltrade (2%)	Eni (operator) 44.4%; Vitol upstream Ghana 35.6% and GNPC 2.0%	
<b>EQUITY</b>	<b>54.37%</b>	<b>45.63%</b>	<b>100.00%</b>				
<b>FISCAL PACKAGE &amp; ANALYSIS</b>							
Royalty Oil	5.00%	5.00%	5.00%	5.00%	4.00%	7.50%	
Royalty Gas (Domestic)	5.00%	4.08%	4.08%	3.00%	3.00%	5.00%	
Royalty Gas (Export)	-	-	-	-	-	-	
Initial GNPC Participation	10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	
Additional Participation	2.50%	5.00%	3.64%	5.00%	3.00%	5.00%	
Commercial Interest [Explore]	-	-	-	-	-	-	
Petroleum Income Tax	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	
<b>ADDITIONAL OIL ENTITLEMENT</b>							
<b>Rate of Return Thresholds</b>							
<12.5%							
12.5%					5.0%	10.0%	
17.5%					10.0%	12.5%	
18.0%							
19.0%		5.0%	5.0%	5.0%			

(continued)

Table 3 (continued)

20.0%		10.0%	10.0%	10.0%	10.0%	10.0%	15.0%	16.0%
22.5%								
25.0%	7.5%	15.0%	15.0%	15.0%	15.0%	15.0%	20.0%	20.0%
30.0%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%		
40.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%		
<b>TRAINING ALLOWANCE (\$mm p.a.)</b>								
Exploration	0.25	0.25	0.25	0.25	0.25			0.20
Development/Production	0.25	0.25	0.25	0.25	0.25			0.20
<b>TECHNOLOGY ALLOWANCE (\$mm)</b>								
<i>At effective date</i>								
<i>At commercial discovery</i>								
<b>SURFACE RENTALS (\$ per sq. km.)</b>								
Initial Exploration Period	\$20	\$30	\$30	\$30	\$30	\$30	\$30	\$30
First Extension Period	\$25	\$50	\$50	\$50	\$50	\$40	\$50	\$50
Second Extension Period	\$30	\$75	\$75	\$75	\$75	\$75	\$75	\$75
Development and Production Period	\$100	\$100	\$100	\$100	\$100	\$100	\$100	\$100
<b>OTHERS</b>								
Withholding Tax Rates on Dividends and Interest	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Loss Carry Forward	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Import Duty	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Export Tax	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
<b>Date signed/ratified</b>	22-Jul-2004	10-Mar-2006	13-Jul-2009	10-Mar-2006	19-Jul-2006	10-Mar-2006	19-Jul-2006	02-Mar-2006

Table 4 Evolution of fiscal terms (2007–2014)

BLOCK	East Cape Three Points	Expanded Shallow Water Tano	Central Tano	South Deepwater Tano	Shallow Water Cape Three Points	South West Salpond	East Keta	South-West Tano	Offshore Cape Three Points South	South-West Cape Three Points
DENOMINATION	COLA & MEDEA	ERIN	AMINI	AGM	SAHARA	BRITANNIA-U	BLUE/HERITAGE-KETA	BLUE/HERITAGE-TANO	UB GROUP	A-Z PETROLEUM
OPERATOR		ERIN (Formerly CAMACO)								
EQUITY PARTNERS	Cola Natural Resources; Medea Development and GNPC	60% Base Energy 15% GNPC Explorecor 25% and GNPC	Anni International, GNPC	AGM Petroleum Ghana; GNPC Explorecor; GNPC	Sahara Energy; Sapholdia; GNPC	BRITANNIA-U Ghana, Hills Oil and GNPC	Heritage, Blue Star, GNPC Explorecor, GNPC	Heritage, Blue Star, GNPC Explorecor, GNPC	UB Resources, Houston Drilling Management, Royalgate Ghana, GNPC	A-Z Petroleum Ghana, ECO Atlantia, GNPC Explorecor, GNPC
<b>FISCAL PACKAGE &amp; ANALYSIS</b>										
Royalty Oil	10.00%	12.50%	12.50%	10.00%	12.50%	10.00%	10.00%	12.50%	12.50%	12.50%
Royalty Gas (Domestic)	5.00%	7.50%	5.00%	5.00%	5.00%	5.00%	10.00%	10.00%	5.00%	5.00%
Royalty Gas (Export)	10.00%	7.50%	10.00%	5.00%	7.50%	7.50%	10.00%	10.00%	10.00%	10.00%
Initial GNPC Participation	10.00%	10.00%	10.00%	10.00%	10.00%	20.00%	11.00%	12.00%	13.00%	13.00%
Additional Participation	17.50%	10.00%	20.00%	15.00%	15.00%	5.00%	9.00%	13.00%	25.00%	20.00%
Commercial Interest [Explorecor]	-	25.00%	-	24.00%	-	-	11.60%	8.80%	-	5.35%
Petroleum Income Tax	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
<b>ADDITIONAL OIL ENTITLEMENT</b>										
Rate of Return Thresholds										
<12.5%										
12.5%	12.5%	12.5%	12.5%	12.5%	8%	12.5%	5.0%	10.00%	10.0%	12.5%
15.0%										
17.5%	15.0%	15.0%	15.0%	15.0%	12%	15.0%	15.0%	12.50%	12.5%	15.0%
20.0%							15.0%			

(continued)

Table 4 (continued)

22.5%	17.5%	17.5%	17.5%	17.5%	15%	17.0%	20.00%	20.0%	17.5%
25.0%								20.0%	
27.5%	22.5%	22.5%	22.5%	22%	22%	22.5%	25.00%	25.0%	22.5%
30.0%									
32.5%	27.5%	30.0%	27.5%	30%	30%	27.5%	30.00%		27.5%
35.0%								30.0%	
<b>TRAINING ALLOWANCE (\$mm p.a.)</b>									
Exploration	0.50	1.00	1.00	1.00	0.50	0.50	0.25	0.25	1.50
Development/Production	0.50	1.00	1.00	1.00	0.50	0.50	0.25	0.25	1.50
<b>TECHNOLOGY ALLOWANCE (\$mm)</b>									
At effective date	1.00	2.00	1.50		1.00	0.50	1.50		2.00
At commercial discovery	2.00				2.00	1.50			
<b>SURFACE RENTALS (\$ per sq. km.)</b>									
Initial Exploration Period	\$50	\$50	\$50	\$50	\$50	\$50	\$50	\$50	\$50
First Extension Period	\$100	\$100	\$100	\$75	\$75	\$100	\$100	\$100	\$100
Second Extension Period	\$100	\$100	\$100	\$100	\$100	\$100	\$100	\$100	\$100
Development and Production Period	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200	\$200
<b>OTHERS</b>									
Withholding Tax Rates on Dividends, Interest	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Loss Carry Forward	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Import Duty	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Export Tax	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
<b>Date signed/ratified</b>	04-Dec-2013	23-Jan-2015	21-Mar-2014	24-Jan-2014	18-Jul-2014	18-Jul-2014	18-Jul-2014	18-Jul-2014	18-Jul-2014

Source: Author's construct based on relevant petroleum agreements published in the Ghana Petroleum Register. Available at: <https://www.ghanapetrroleumregister.com> (Accessed: 23 July 2021)

and Puyo, 2016). This approach also allows us to analyse the effect of the interactions of different fiscal regime parameters.

We utilised data for field sizes and cost for deepwater offshore West Africa, as well as average fiscal terms given under the respective petroleum contracts in Ghana. These together with some general assumptions about oil prices, cost of capital, discount rate and inflation are modelled. For effective and accurate comparison of fiscal regimes for deepwater fields, there is a need for fields and costs to reflect the peculiarities of the said petroleum province. Thus, a suite of model fields and costs as it pertains to deepwater offshore West Africa are assumed so that only the marginal effects of the respective fiscal terms in the contracts are captured (Agalliu, 2011; Daniel et al., 2010; Johnston 2007; Blake and Roberts, 2006). Furthermore, as widely practiced within the literature, our model is constructed using three representative offshore fields: large (750 million barrels of oil equivalent: mmboe), medium (250 mmboe) and small (50 mmboe).<sup>18</sup> Table 5 summarises these models and other assumptions used while Fig. 3 shows the production profiles of the three fields.

Other assumptions included in the model are as follows:

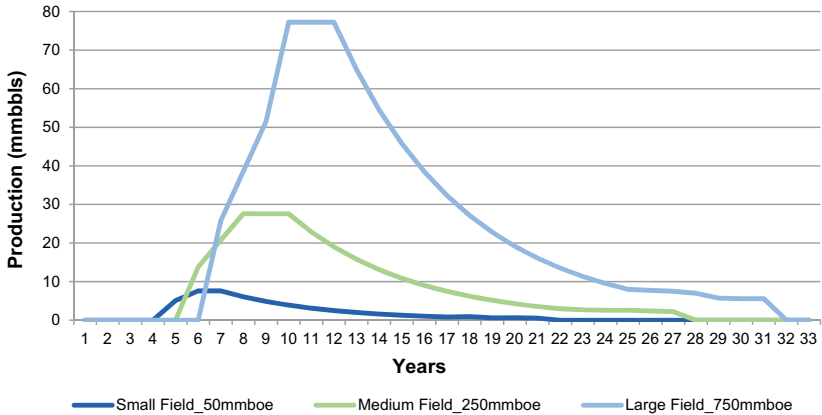
1. A base case oil price of \$60/bbl in constant (real terms): Various price range sensitivities are undertaken from \$30-\$100/bbl to test Ghana's fiscal regime performance under different oil price scenarios.
2. Base oil price inflation of 1.5% per annum from first year onwards.
3. Base cost inflation of 2% per annum from first year onwards.
4. Discount rate of 10%.
5. Projects are financed with 75% debt-to-equity ratio (gearing) for both exploration and appraisal costs, and capital costs. The cost of debt is assumed to be 7% and the loan period is 7 years.
6. The economic limit is modelled when revenues become less than operating cost plus royalty. With higher royalty rate, economic recovery becomes less.

<sup>18</sup> See Nakhle (2008).

**Table 5** Project assumptions

<i>Field number</i>	<i>Unit</i>	<i>Small field (50mmboe)</i>	<i>Medium field (250mmboe)</i>	<i>Large field (750mmboe)</i>
Recoverable reserves	mmbbls	50	250	750
Exploration and appraisal costs	\$/bbl (real)	2.00	2.00	2.00
Development costs (capex)	\$/bbl (real)	8.98	7.00	6.00
Operating costs	\$/bbl (real)	7.66	8.17	8.02
Decommissioning costs	\$/bbl (real)	1.40	1.20	1.00
<b>Total field costs</b>	<b>\$/bbl (real)</b>	<b>20.0</b>	<b>18.4</b>	<b>17.0</b>
Exploration period	years	2	2	2
Development period	years	2	3	4
Abandonment period	years	1	2	3
Depreciation SL	years	5	5	5
Base year	year	2021	2021	2021

Source Authors' estimates based on various industry reports



**Fig. 3** Production profile for the three oilfields (small, medium and large)

#### 4.2 *Summary of Modelled Fiscal Terms*

Fiscal terms were compiled using the petroleum agreements signed by the international oil companies with the government as well as the petroleum law and regulations. All the fiscal elements pertaining to Ghana's offshore petroleum contracts are captured together with their interaction with other parts of the model. The sources of revenue in Ghana's contracts come from the following: royalty; carried interest—Ghana does not incur costs during exploration and development but pays on production; paying/additional interest; petroleum income tax; additional oil entitlement; surface rentals; training allowance; capital gains tax and dividends; and withholding taxes. Bonuses are not included in modelling as they are not counted as petroleum cost.

For the purposes of this work, we selected fiscal terms contained in four (4) agreements that encompass the range of agreements signed by the Ghanaian government over the almost past two decades (Table 6). These are:

- Contract 1 [Tullow: Jubilee WCTP&DWT Unitised]
- Contract 2 [Eni: Offshore Cape Three Points]
- Contract 3 [AGM: South Deepwater Tano]
- Contract 4 [Exxon: Deepwater Cape Three Points].

#### 4.3 *Fiscal Evaluation and Rating Criteria*

The evaluation criteria used are summarised in Table 7. From a government's perspective, the key indicators of importance are the average effective tax rate (AETR), which is a measure of government take; the marginal effective tax rate (METR) or the tax wedge; and progressivity of the fiscal regime (Luca and Puyo, 2016). These indicators are particularly useful when comparing existing in-country regimes with alternative regimes.

**Table 6** Summary of modelled fiscal terms

<i>Equity partners</i>	<i>Contract 1 [Tullow: Jubilee WCTP&amp;DWT Unitised]</i>	<i>Contract 2 [Eni: Offshore Cape Three Points]</i>	<i>Contract 3 [AGM: South Deepwater Tano]</i>	<i>Contract 4 [Exxon: Deepwater Cape three points]</i>
Contractor 1	35.47%	44.40%	66.00%	80.00%
Contractor 2	24.08%	35.60%	0.00%	5.00%
Contractor 3	24.08%	0.00%	0.00%	0.00%
Contractor 4	2.73%	0.00%	0.00%	0.00%
<b>IOC Consortium</b>	<b>86.36%</b>	<b>80.00%</b>	<b>66.00%</b>	<b>85.00%</b>
NOC initial interest (free carried interest)	10.00%	15.00%	10.00%	15.00%
NOC additional interest (paying)	3.64%	5.00%	0.00%	0.00%
NOC commercial interest	0.00%	0.00%	24.00%	0.00%
<b>Total</b>	<b>100.00%</b>	<b>100.00%</b>	<b>100.00%</b>	<b>100.00%</b>
Oil royalty	5.00%	7.50%	10.00%	10.00%
Petroleum income tax	35.00%	35.00%	35.00%	35.00%
Depreciation rate SL	20%	20%	20%	20%
<b>Additional oil entitlement (AOE)</b>				
Rate of return (RoR)				
First account	19.00%	12.50%	12.50%	15.00%
Second account	20.00%	17.50%	17.50%	20.00%
Third account	25.00%	22.50%	22.50%	25.00%
Fourth account	30.00%	27.50%	27.50%	30.00%
Fifth account	40.00%		32.50%	
<b>AOE tax charges</b>				
First account	5.00%	10.00%	12.50%	10.00%
Second account	10.00%	12.50%	15.00%	15.00%
Third account	15.00%	16.00%	17.50%	20.00%
Fourth account	20.00%	20.00%	22.50%	25.00%
Fifth account	25.00%		27.50%	
<b>Date signed/ratified</b>	13 July 2009	02 March 2006	24 January 2014	28 November 2018

Source Author's depiction based on petroleum contracts



**Table 7** Summary of fiscal evaluation criteria

<i>Agent</i>	<i>Criteria</i>	<i>Metric used and rationale</i>
Investor	Neutrality	METR (pre-tax IRR minus post-tax IRR divided by pre-tax IRR)  $\text{METR} = \frac{\text{Pre-tax IRR} - \text{Post-tax IRR}}{\text{Pre-tax IRR}}$
	Progressivity	AETR mapped to different oil prices and pre-tax IRRs
Government	Investor risk (identification of risks)	<ul style="list-style-type: none"> <li>• 12 Payback period</li> <li>• PI ratio</li> <li>• Coefficient of variation of NPV and IRR</li> </ul>
	Tax revenue	AETR (Government revenues as a share of pre-tax net cash flow at various discount rates) <sup>19</sup>  $\text{AETR} = \frac{\text{NPV (Discounted Govt. Revenue)}}{\text{NPV(Discounted Pre-tax net cash flows)}}$
	Government risk (identification of risks)	<ul style="list-style-type: none"> <li>• Mean NPV of government revenues</li> <li>• Coefficient of variation of government revenue</li> <li>• Government share of benefits during first 10-years of the respective projects (time profile of government revenue)</li> </ul>

Source Adapted from Banda (2019) and Laporte and De Quartrebarbes (2015)

<sup>19</sup> Two main variations of the AETR are usually estimated in the literature and in practice. These are the **government take** and **state take**. Government take is the sum of the state's royalty entitlements, special petroleum taxes, profit oil, and corporation taxes as well as bonuses, rentals and other fiscal and quasi-fiscal levies. On the other hand, the state take includes the government take as well as revenues from direct participation by the NOC (GNPC in Ghana's case). In other words, the state take is the percentage of a project's gross operating profit, which accrues to a sovereign government by way of royalties and taxes paid by investors, plus the operating profit (cash flow effect) attributable to the state's direct participation such as carried and participating interest in a project. For our results we report the government take (without state participation) on a discounted and undiscounted basis. See World Bank (2019), van Meurs (2016), Tordo (2007), and Johnston (2007).

## 5 RESULTS AND DISCUSSION: ASSESSING THE EFFICIENCY OF GHANA'S PETROLEUM FISCAL REGIME

This section presents the modelling work carried out to quantitatively assess Ghana's upstream fiscal regime. We also compare Ghana's fiscal terms with those of other oil and gas producers in the African region and beyond. The quantitative assessment is based on the indicators and metrics discussed in the preceding section.

### 5.1 *Base Metrics*

The metrics resulting from the base case economic analysis are shown in Table 8. The average post-tax government take (AETR) and marginal effective tax rate (METR) are estimated at 51.38 and 31.07% respectively for all three field sizes and four contract terms. The AETR, in our analysis, is the discounted government revenue flows from three fiscal instruments, namely: royalties, IOC income taxes, and windfall taxes (AOE). This is then divided by discounted project pre-tax net cash flows or the gross operating margin (economic rent). Specifically, for the field sizes, average government takes are estimated at 51.38, 50.98 and 50.42% for the small field (50 mmboc), medium field (250 mmboc) and large field (750 mmboc), respectively. The corresponding average METRs are 31.07, 30.3 and 27.71% respectively. What this indicates is that the government takes marginal increases with decreasing field sizes or prospectivity, indicating relative inflexibility of the fiscal regime. This effect is, however, fully tested out with additional sensitivity analysis as discussed in the next section.

In essence, the 51% AETR indicates that the fiscal regime is largely competitive or pro-investment in managing the trade-offs between investment promotion and securing revenues to the State, especially when compared with other countries in the sub-region and beyond—see Sect. 5.3 for the country comparative analysis. Our government's take is also largely consistent with that reported in the wider extant literature for Ghana. For example, the World Bank (2019) reports a 54% government take for Ghana at \$75/bbl. Likewise, Kankam and Ackah (2014) report a 37% state share, which is rather on the low side. Ashikwei (2019) also reports a government take of 41.74%.

However, as the World Bank (2019, p. 50) notes, “*there is no right level of government or state take and whether it is optimum can usually only be determined in retrospect, nor is the optimum level a constant*”. As a general rule of thumb, having a high level of government take, especially for nascent oil-producing countries without large reserves, can stifle industry activity by disincentivising or curtailing active field development (World Bank, 2019; Balza and Espinasa, 2015).

Regarding the four contracts analysed, Contract 1, which represents the unitised Jubilee field (WCTP&DWT) terms, ranks the lowest in terms of government take at 44.75%. This is irrespective of the field size. This is followed by Contract 2 (Offshore Cape Three Points) at a 49.79% average government take and then Contract 3 (South Deepwater Tano) at 52.96%, and finally Contract 4 (Deepwater Cape Three Points) at 58.0%. This is explained by the fact that Ghana has increased its fiscal terms over the past years since the play-opening Jubilee field discovery. For example, while Jubilee field was a play-opening discovery in the wider West Africa Transform margin, successive post-Jubilee contracts signed between the Ghanaian government and international investors factored in the de-risking to demand increased fiscal take such as via higher royalties and also carried and participating interests. Fiscal terms were tightened following the Jubilee discovery in the new contracts signed after 2010 and with the passage of the new exploration and production Act (Act 919), resulting in increased government take. For example, whereas pre-Jubilee contracts had 4–7.5% oil royalty rates, post-Jubilee contracts have 10–12.5% oil royalty rates (Nakhle and Acheampong, 2020).<sup>20</sup> Also, the Ghanaian Government through the Ministry of Energy, set a minimum 12.5% royalty rate, minimum 5% additional participation paying interest and minimum US\$250,000 signature bonus for all six blocks on offer spanning various water depths in its maiden licensing round conducted from 2018 from 2019.<sup>21</sup>

<sup>20</sup> See also Tables 3 and 4.

<sup>21</sup> See pg. 14 of Appendix A “Invitation to Tender document for First Oil & Gas Licensing Round”, published by the Ministry of Energy (21st January 2019).

**Table 8** Fiscal metrics at \$60/bbl

<i>Large field (750 million barrel)</i>	<i>Average effective tax rate (AETR)</i>	<i>Marginal effective tax rate (metr)</i>	<i>NPV per boe (\$/boe)</i>
Contract 1	43.65%	25.12%	5.12
Contract 2	48.99%	31.06%	3.75
Contract 3	51.65%	27.32%	3.06
Contract 4	57.38%	27.34%	4.11
<b>Average</b>	<b>50.42%</b>	<b>27.71%</b>	<b>4.01</b>
<i>Medium field (250 million barrel)</i>	<i>Average effective tax rate (AETR)</i>	<i>Marginal effective tax rate (METR)</i>	<i>NPV per boe (\$/boe)</i>
Contract 1	44.07%	27.13%	5.88
Contract 2	49.68%	33.68%	4.24
Contract 3	52.72%	29.90%	3.44
Contract 4	57.46%	29.42%	4.75
<b>Average</b>	<b>50.98%</b>	<b>30.03%</b>	<b>4.58</b>
<i>Small field (50 million barrel)</i>	<i>Average effective tax rate (AETR)</i>	<i>Marginal effective tax rate (METR)</i>	<i>NPV per boe (\$/boe)</i>
Contract 1	46.53%	32.22%	6.79
Contract 2	50.71%	39.22%	5.01
Contract 3	54.51%	35.70%	3.92
Contract 4	59.23%	34.73%	5.54
<b>Average</b>	<b>52.75%</b>	<b>35.47%</b>	<b>5.32</b>

Source Authors' estimates

## 5.2 *Beyond The Government Take: Progressivity of Ghana's Fiscal Regime*

The basic question for this analysis remains: Is Ghana's oil tax system progressive? This is more the case because the attractiveness of a fiscal regime to investors and the sustainable or fair level of government take at any point in time is a function of several variables. This includes commercial risks proxied by oil prices; the geology and the size and productivity of a field; country-level operational costs or even within basins in the same country; and other country alternatives of oil and gas companies (the neighbourhood effect) (World Bank, 2019; Nakhle, 2008, 2010).

Therefore, the optimum level of government take will fluctuate over time. More so, the base AETR, which is calculated using a single price path and one set of cost assumptions, does not fully capture or explain

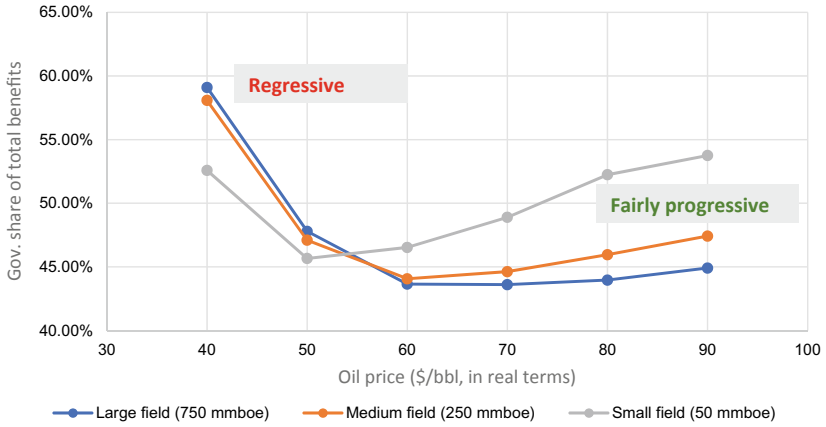
how a fiscal regime fares in different circumstances (the progressivity of the regime) (Luca and Puyo, 2016). Thus, there is a need to estimate the government take over a range of different costs, prices and corresponding pre-tax IRRs.<sup>22</sup>

Figures 4 and 5 show the AETR for the three fields using two pre-Jubilee and post-Jubilee contracts mapped to different oil prices. Overall, Ghana's hybrid fiscal regime is regressive at the lower end of the oil price scale if oil prices are below \$60/bbl., while being slightly progressive with increasing oil prices above \$60/bbl; thus, the Ghanaian State collects a higher share of the rents the lower these rents become through lower prices. The reverse also holds true. An explanation for this is that Ghana's fiscal regime has both regressive (royalties) and progressive structures (CIT and AOE) with them which work to counteract each other. At lower oil prices, royalties, which are a percentage share of the gross production of crude oil delivered to the State, are collected regardless of the underlying productivity of the ring fence area—field or development and production area. The responsiveness of the fiscal structures to higher oil price changes reflects more of the corporate income taxes and additional oil entitlements being collected relative to the royalties.

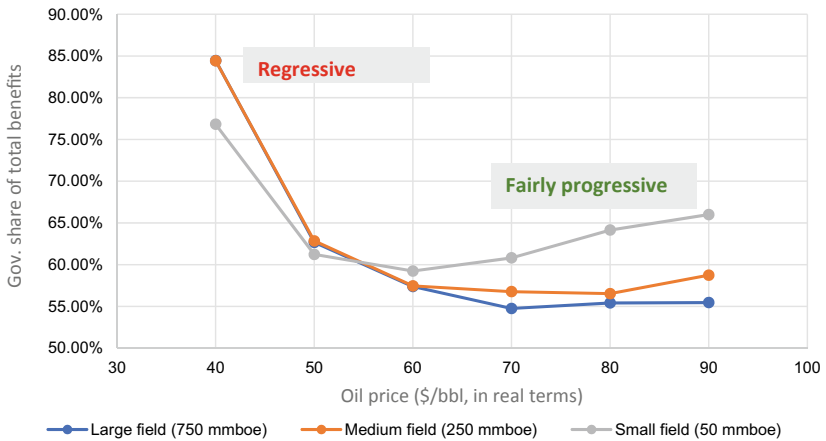
### 5.3 *Trend Analysis: Ghana's Fiscal Regime Versus Regional and Global Benchmarks*

In terms of Ghana's fiscal regime, there have been some changes such as the minimum carried interest being raised from 10 to 15% for instance, and provision made for capital gains tax, as well as bonuses. The two fiscal elements that bring Ghana the most revenue are its direct interest (stake) in the field as well as the royalty component (Fig. 6). Given the foregoing, accountability bodies such as the Public Interest and Accountability Committee (PIAC) have strenuously argued that in negotiations with the oil companies in respect of the fiscal regime, there is the need for Ghana to negotiate tenaciously in respect of these.

<sup>22</sup> As stated earlier in Sect. 2.2, progressive fiscal regimes collect a higher share of the rents from rising oil prices or lower costs, among others.

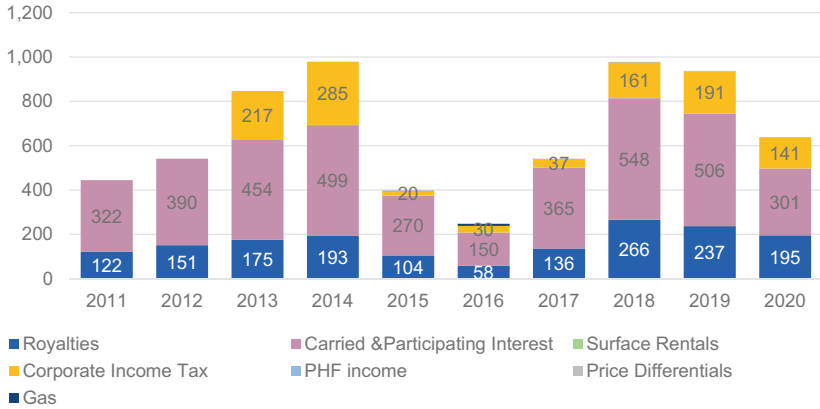


**Fig. 4** State share of profits with increasing oil price, Jubilee WCTP&DWT Unitted

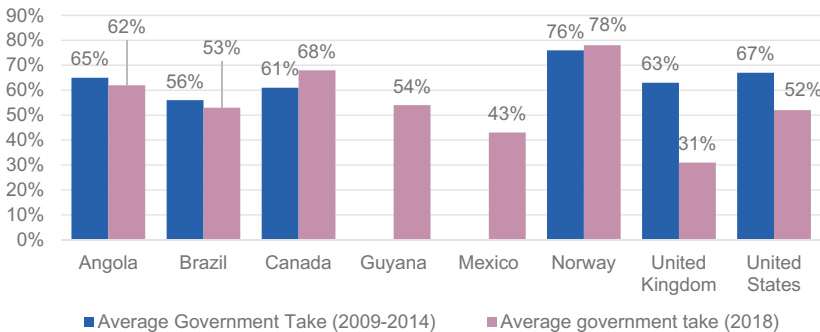


**Fig. 5** State share of profits with increasing oil price, Deepwater Cape Three Points

Despite these calls, however, there is a need to compare and contrast Ghana’s fiscal terms with African and other countries; more so, given that these countries tend to compete for the same petrodollar FDIs. Figure 7 shows a comparison of the government take (the average effective tax



**Fig. 6** Analysis of petroleum receipts, 2011–2020 (US\$ million) (*Data source* Ministry of Finance/Bank of Ghana/PIAC)



**Fig. 7** Average government take for selected countries (2009–2014) and 2018 (*Note* Average government take is the NPV of the government take divided by the sum of the NPV of the free cashflow and the NPV of the government take. *Source* Martén et al. (2015) and Agalliu et al. [2018])

rates: AETR) for some selected countries while Fig. 8 shows ranks of the government take relative to remaining recoverable reserve in some countries. Generally, countries with higher reserves potential tend to have a relatively higher government take (Agalliu, 2011). Between 2009 and 2014, government take was about 52% for most countries but was more

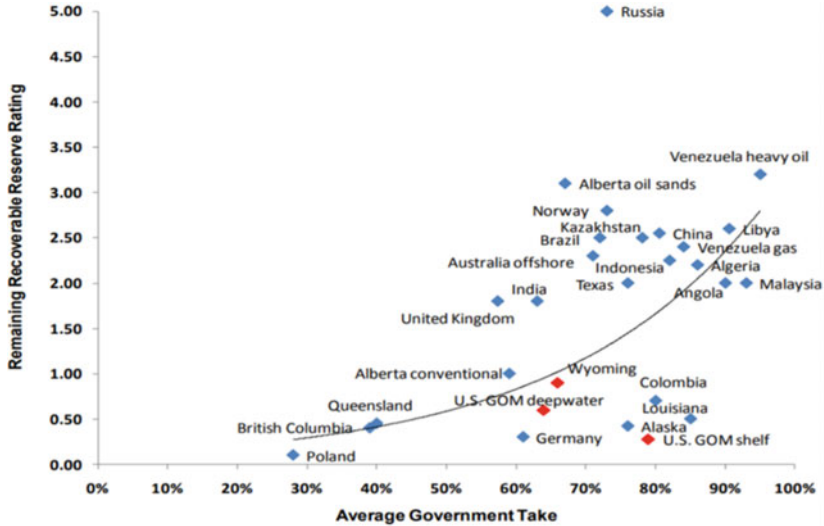


Fig. 8 Government take relative to remaining recoverable reserve ranking (Source Agalliu [2011, p.11])

than 80% in others such as Algeria and Indonesia (Martén et al., 2015). Also, the commodities super-cycle with rising prices from 2000 to 2014 resulted in government take increasing from an estimated US\$9.90 per barrel of oil equivalent (boe) to US\$30.40 (Martén et al., 2015). The IMF (2012, p. 6) also reports average AETR in the petroleum-producing countries being between 65 and 85%, and that “*fiscal regimes that raise less than these benchmark averages may be cause for concern*”.

However, as Nakhle (2010) notes, a government take of between 50 and 60% might be acceptable at US\$60/bbl and not at above US\$100/bbl. In fact, in relation to the 2014–2018 oil price slump, several petroleum-producing countries either took action to lower or increase their government take, conducted competitiveness reviews or just did nothing (stayed the course) (Nakhle and Acheampong, 2020; Davis and Smith, 2020; Agalliu et al., 2018; Crystol Energy, 2018). For example, Norway, which is touted as having one of the world’s most stable fiscal regimes, implemented changes to adapt it to local and international conditions (Nakhle and Acheampong, 2020). Norway reduced the total uplift from 22% in 2016 and also reduced CIT marginal rates by one



percentage point per year from 25% in 2016 to 22% in 2019 (Nakhle and Acheampong, 2020). Other governments that reviewed their fiscal terms included Angola with newly elected President João Lourenço enacting several reforms and halving tax rates on small and marginal fields as soon as he assumed office in 2017 (Nakhle and Acheampong, 2020).

Considering the broad totality of the data and modelling exercise, we see that the Ghanaian fiscal system results in AETR levels are less than the IMF benchmark range of between 65 and 85%. However, the inclusion of the State carried and participating interest (state take) into the mix pushes the AETR into the 65%–75% range, as confirmed in other studies such as Nakhle and Lassourd (2019). Within the wider African context, Diouf and Laporte (2017) report the following AETRs at \$50/bbl and 10% discount rate: Senegal (Concession:53%; Production sharing:59%); Congo Republic (Production sharing: 87%); Niger (Concession:80%); Algeria (Concession:124%). Overall, the general level of Ghana's government and state take is within reasonable bounds.

## 6 REFORMING GHANA'S WINDFALL TAXATION REGIME (AOE)<sup>23</sup> AND OTHER MATTERS ARISING

### 6.1 *Ghana's Windfall Taxation Regime*

It bears noting that the fiscal regime is constantly being assessed to see how best Ghana can obtain optimum revenues from its industry. One of the fiscal instruments that has been the object of debate and scrutiny between the IOCs and Ghanaian State agencies is the AOE, which is yet to be triggered after ten years of oil production. It is the case that this component of Ghana's fiscal regime is being scrutinised to see how best it can be modified in order to benefit the State.

To capture the economic rent, governments impose a special petroleum windfall or resource rent tax (RRT), which is not paid before a project reaches payback and achieves a certain rate of return (Moore,

<sup>23</sup> This section is largely extracted from a report authored by Nakhle and Acheampong (2017) for the Ghana Oil and Gas for Inclusive Growth (GOGIG programme). The overriding objective of the report was to assess the Additional Oil Entitlement (AOE), Ghana's version of a petroleum windfall tax, its structure and design, strengths and weaknesses, thereby contributing to the existing debate on the year the tax was or will be triggered for the Jubilee field and whether any revenues are indeed overdue as suspected by some local stakeholders.

2017; Johnston and Johnston, 2015; Land, 2010; Boadway and Keen, 2010; Lund, 2009; Garnaut and Ross, 1975, 1979).

Two key features distinguish the RRT from the corporate income tax (CIT):

1. The windfall tax is levied on a project or a field's cash flows whereas the CIT is on a company basis.
2. To calculate the CIT base, deductions include interests and depreciation allowance. In contrast, for the windfall tax, interest expenses are usually not permitted as a deduction, while capital costs secure immediate relief.

The RRT can take many forms:

1. A common method is based on an R-Factor, which is linked to the payback of the investment (the ratio of cumulative post-tax receipts to cumulative expenditures, hence also known as the payback ratio) (Moore, 2017; Johnston and Johnston, 2015; Land, 2010). Theoretically, an R-factor of less than 1 implies that petroleum costs have not been fully recovered yet while a larger R-factor indicates more profitable operations. The RRT is imposed only when a project reaches a specific ratio, for example,  $R \geq 1.5$ .
2. The other common method is the use of Rate of Return (ROR), or the internal rate of return (IRR), as a threshold: in this case, the RRT is imposed only when cumulative net cash flows (NCFs) turn positive (Moore, 2017; Johnston and Johnston, 2015; Land, 2010). Negative cumulative NCFs are carried forward in one year; they are normally uplifted by a minimum rate of return requirement and added to the next year's NCFs. The uplift is often characterised as a proxy for financing costs or the minimum required ROR for the investor. The accumulation process continues until the cumulative NCFs turn positive and at this point the RRT applies.

The Additional Oil Entitlement (AOE) is Ghana's version of an IRR-based windfall tax scheme in the upstream oil and gas sector. The State is entitled to an additional portion of the contractor's share (referred to as the AOE) of crude oil production from each development and production

area. The AOE is calculated separately for each contractor in each development and production area based on the contractor's NCFs from that area. Subject to specific provisions outlined in the contractor's petroleum agreement, the AOE is computed either monthly, quarterly or annually.

In line with the terms of the petroleum agreement and the underlying literature on windfall taxation, Nakhle and Acheampong (2017) carried out an assessment of the current AOE scheme, as it pertains in the Jubilee agreement with an aim to simplify the existing scheme. In total, four scenarios were modelled:

1. **Scenario 1 (Status Quo/4-Tier AOE)**<sup>24</sup>: This has four tiers AOE and is calculated based on the post-tax NCF of the project. The trigger IRR threshold starts at 19% real terms and step-wise differential tax rates are charged based on pre-defined IRRs.
2. **Scenario 2 (Three-Tier AOE)**: This scenario is similar to the existing AOE scheme but with a lower IRR trigger threshold (starting at 12.5% instead of 19%—similar to the terms of the Offshore Cape Three Points (OCTP) contract) and using three tiers instead of four. The headline tax rates, applied in Scenario 1, were maintained for consistency, except that the maximum tier AOE rate is now 15% instead of 20%. The aim here is to show that similar outcomes can be achieved by maintaining a maximum three tiers while reducing the minimum threshold IRR to 12.5%.
3. **Scenario 3 (Single-tier and rate special petroleum tax)**: Instead of a multi-tier tax, a single tier tax rate applies at 25%, which results in a relatively higher marginal tax rate (MTR) applied on the contractor's share of crude oil.<sup>25</sup> A single 15% pre-determined IRR is used to compound the cash flows. The tax works like Norway's Special Petroleum Tax (SPT) or Australia's petroleum resource rent tax (PRRT) (Norwegianpetroleum.no, 2021; Australian Government Taxation Office, 2021; Deloitte, 2021, Callaghan, 2017). The aim here is to show that similar and sometimes better outcomes can be achieved with a simplified system.

<sup>24</sup> Note that for Scenarios 1–3, all the trigger point tax rates were set at 5, 10 and 15% in line with the Jubilee field contract to ensure consistency.

<sup>25</sup> MTR is the amount of *tax* paid on an additional dollar of income.

4. **Scenario 4 (R-Factor):** Instead of using the IRR as trigger point, this scenario considers another measure of profitability—the R-factor. An uplift factor is allowed for the costs and the tax has three tiers and all headline tax rates are maintained for consistency. A key difference to the other three scenarios, however, is that it applies on a pre-CIT basis.

The findings indicated that Ghana's current AOE (Scenario 1) regime lags all the other scenarios in terms of the year it is activated, as well as in terms of the size of the revenues generated to the government (Table 9). It was the only scenario which did not generate any revenues even under the low oil price scenario, unlike the other three (Scenarios 2 to 4). The status quo generated the lowest revenues to the government under all the price assumptions considered because of its higher trigger point. A simple lowering of that trigger, even with a lower maximum tax rate and less tiers, resulted in higher government revenues, also starting at an earlier period. The R-factor (Scenario 4) scheme had the earliest trigger point given its distinctive feature whereby windfall tax is imposed on a pre and not post-CIT basis. However, it did generate the biggest windfall in terms of revenue capture. These results supported the following proposition: Should the government decide to maintain the post-CIT windfall scheme going forward, then it may want to consider a simple flat rate RRT at a higher marginal rate of tax. This is not only computationally tractable but aligns with the administrative capacity of the revenue institutions. Having more tiers is unlikely to translate into higher revenues.

## 6.2 *Need for Cost Control and Auditing*

Besides the fiscal instruments or even regime type, the ability to keep costs in check (control) is paramount. Cost control is the engine that determines how countries generate enough petroleum revenues—that is, keep the size of the pie in check. In Ghana's case, monitoring costs are even more pertinent given the hybrid concessionary regime the country has adopted. As highlighted earlier, most of the revenues generated since first oil have come from the State's direct interest (stake) in the fields via the CAPI and royalties (see Sect. 5.3). These two instruments are not a function of costs (royalties are calculated on gross revenues); they also have lower marginal rates. However, instruments with much higher marginal

**Table 9** Scale and timing of AOE revenues

<i>Low-case oil prices</i>	<i>Amount (USD million)</i>	<i>First year triggered</i>
Scenario 1 (Status Quo/4-Tier AOE)	N/A	N/A
Scenario 2 (Three-Tier AOE)	35	2020
Scenario 3 (Special Petroleum Tax)	298	2022
Scenario 4 (R-Factor)	110	2015
<i>Mid-case oil prices</i>	<i>Amount (USD million)</i>	<i>First year triggered</i>
Scenario 1 (Status Quo/4-Tier AOE)	17	2032
Scenario 2 (Three-Tier AOE)	26	2019
Scenario 3 (Special Petroleum Tax)	330	2021
Scenario 4 (R-Factor)	110	2015
<i>High-case oil prices</i>	<i>Amount (USD million)</i>	<i>First Year Triggered</i>
Scenario 1 (Status Quo/4-Tier AOE)	19	2024
Scenario 2 (Three-Tier AOE)	11	2018
Scenario 3 (Special Petroleum Tax)	405	2020
Scenario 4 (R-Factor)	110	2015

Source Nakhle and Acheampong (2017, p. 13)

rates such as the Petroleum (Corporate) Income Tax (35%) and Additional Oil Entitlement (AOE: with corresponding additional profits tax rates varying from 5% to 30%) are dependent on costs and other incentive measures. These incentive measures include the thin capitalisation and ring-fencing provisions, loss carry forwards, and capital allowances (tax depreciation), which all reduce the potential tax earnings—that is, Corporate Income Tax is levied on profit and not on gross revenue. That

is, computing a contractor's net income from petroleum operations for income tax or AOE purposes is subject to eligibility or otherwise for various cost deductions.

Unlike a typical production sharing contract (agreement)—PSC/PSA—where there are clear ceilings on costs in any period using the **cost oil**<sup>26</sup> instrument, Ghana's hybrid concessionary regime does not have any cost ceiling. This limits the ability of the State to capture a larger share of the prospective revenues in the absence of strong and effective cost controls. Under the respective petroleum agreements and also Ghana's Model Petroleum Agreements, the Petroleum Commission (the regulator), as well as GNPC (the national oil company), and the Ghana Revenue Authority (GRA), play critical cost auditing and accounting functions. In this regard, some new legislation, such as the Petroleum (General) Regulations 2018 (L.I. 2359) as amended, have been passed to control petroleum costs claimed by the IOCs. For example, under Section 40(9) of L.I. 2359, "*the costs for additional exploration operations shall, in the absence of approval by the Commission, only be allowable petroleum costs where the additional operations result in a new or extended commercial discovery*". This provision seeks to prevent gold plating whereby contractors undertake extra exploration work on their concessions without regulatory approval but seek to claim the costs from revenues within the existing producing concession or ring-fence even in the event of a dry hole. Gold plating within a fiscal regime refers to the unintended consequence or situation whereby the regime gives contractors an incentive to make additional capital investments to claim a more significant share of project revenues and thereby lower returns for the government (Medeiros et al., 2019; Moore, 2017; Sreenivas and Sant, 2009; Ameh, 2005).

Discussions with some industry stakeholders point anecdotally to some oil companies engaging in gold-plating behaviours. In some instances, oil companies have had to make extra unanticipated investments in the fields, which have significantly reduced the tax base. For example, the Jubilee field partners in 2011 had to drill new wells at an estimated US\$1.1 billion cost in addition to US\$400 million of remedial acid stimulations (Offshore Magazine, 2012; Offshore Energy, 2012). Some of the first production wells failed following a fast-tracked development and

<sup>26</sup> See Cameron, P. D., & Stanley, M. C. (2017). *Oil, gas, and mining: A sourcebook for understanding the extractive industries*. World Bank Publications.

production programme. The monies spent on these new wells and other remedial works are cost recoverable (petroleum cost) under the respective petroleum agreements signed with the State. This is part of the reasons why Ghana's oilfields have generated an estimated US\$32 billion in value between 2011 and 2020 but only US\$6.5 billion of receipts have accrued to the State.

In effect, the ability of countries to collect enough revenues using such hybrid schemes without any cost recovery limits is highly dependent on strong cost controls and audits. Ghana has over the years improved on its ability to monitor petroleum costs. For example, technical assistance provided by some donors such as the FCDO-funded Ghana Oil and Gas for Inclusive Growth (GOGIG) programme to the Petroleum Commission to purchase industry software for reservoir simulation and cost benchmarking has improved process workflows, thereby lowering costs, boosting production, and increasing productivity. The regulator can now comprehensively review Plans of Development (PoDs) and make cost savings recommendations (GOGIG, 2019). A case in point is the recent review of Aker PoD for the Deepwater Tano Cape Three Points (DWTCTP) block located offshore Ghana, which according to sources, led to US\$450 million cost savings (GOGIG, 2019).

Despite these positives, there are significant institutional challenges regarding the capacity of some state institutions to monitor petroleum costs efficiently. In the absence of a change to the fiscal regime, the ability of Ghana's regulatory and commercial institutions to monitor and audit costs will determine the extent to which the nation will generate significant revenues beyond just royalties and the CAPI.

## 7 CONCLUSIONS AND POLICY IMPLICATIONS

The study examined the competitiveness of Ghana's petroleum fiscal regime against some key fiscal regime evaluation criteria, namely: efficiency of targeting economic rents, profitability, risk sharing, neutrality and progressiveness. Whether fiscal systems are attractive depends not only on the overall government take, but also several corollary factors. In Ghana's case, one needs to weigh the country's relatively small production base and geological potential vis-à-vis the Ghanaian government's priorities for the upstream sector to create a vibrant industry that can support the local economy.

Based on the study's findings, there is a requirement to further reform and revise the tax regime for Ghana's oil and gas sector as it heads into the next decade of production, even with the competing pressures of the looming . This will help attract the right calibre of domestic and foreign investors and mobilise adequate domestic revenue to help develop and grow the country to foster inclusive development.

We find that the fiscal regime remains favourable overall compared to regional peers within this context. However, the relatively high royalties for new contracts vis-à-vis the country's low resource base could serve as a disincentive to investments as these are often regressive. Also, the current IRR-based AOE profit-sharing discriminates between petroleum agreements for similar geological risks. That is, the AOE does not adequately capture windfall profits with respect to different field sizes. Furthermore, simply lowering the AOE trigger, even with a lower maximum tax rate and less tiers, can result in higher government revenues and earlier timing. Thus, the applicable AOE can benefit from reducing the tiers and lowering the threshold. For example, the multi-tier AOE can be reduced to a single headline rate—for example, 30%, and which is able to generate more revenues for the government.

Ghana can also consider introducing targeted fiscal packages aimed at maximising economic recovery of over 500 mmboc of stranded reserves, which are currently not being exploited for various economic reasons, according to government statistics. The government can encourage IOCs to team up with the national oil company (GNPC) and the Petroleum Commission to develop hub infrastructure or tie in of marginal fields into existing infrastructure. Such an approach needs to be anchored on asset stewardship of critical hubs through regional and area development strategies. Within this setup, targeted fiscal incentives such as reductions in tax on tariff income, small field allowance (SFA) or uplift scheme can be introduced to encourage E&A expenditure within critical hub catchment areas. This can be piloted, targeting specific stranded assets.

Lastly, the introduction of supplementary regulation or an oil taxation manual that explains fiscal terms in greater clarity and syncs with the Income Tax law would benefit all stakeholders. The Ghanaian tax authorities can produce this manual, as in Australia, where the Petroleum Resource Rent Tax Assessment Act 1987 (as amended) provides granular details on how the tax is assessed. The Australian government also provides a detailed Excel-based worksheet and document for illustrative purposes, allowing operators to input their data and select different



assumptions to show the inner workings of the PRRT, including potential taxes due.<sup>27</sup> Similarly, in the UK, the HM Revenue & Customs has a comprehensive Oil Taxation Manual that spells out the law and practice for the oil and gas fiscal regime. The manual is regularly updated and covers petroleum revenue tax, ring-fence, corporation tax, supplementary charges, and decommissioning expenditure relief.<sup>28</sup>

## APPENDIX: FISCAL CALCULATIONS—CASH FLOW METHODOLOGY

The project net cash flow ( $NCF_t$ ) is computed by matching the relationships among the input variables. They are the gross revenues per year ( $GR_t$ ), royalty paid per year  $ROY_t$ ), total recoverable costs per year ( $COSTS_t$ ), income tax paid per year ( $TAX_t$ ) and additional oil entitlement paid per year ( $AOE_t$ ). It is defined as:

$$NCF_t = GR_t - ROY_t - COSTS_t - TAX_t - AOE_t \quad (1)$$

Additionally, we estimate the net present value (NPV) by calculating the discounted revenue for each year using the formula:

$$NPV = \sum_{t=P_1}^T \frac{CF_t}{(1+r)^t} - \sum_{t=C_1}^N \frac{I_t}{(1+r)^t} \quad (2)$$

where,  $CF_t$  = the cash flow at given time,  $r$  = the discount factor,  $I_t$  = investments at time  $t$ ,  $P_1$  = first year of production,  $C_1$  = first year investment,  $N$  = total investment years,  $T$  = total years of cash flow.

The NPV methodology is justifiable by the fact that it properly accounts for all the relevant revenue streams and costs, considering the time value of these cash flows. Other project metrics such as the internal rate of return (IRR), discounted profitability index (DPI), payback period, undiscounted government take and NPV/BOE are also reported.

The respective components that make up the  $NCF_t$  are elaborated as follows:

<sup>27</sup> See <https://industry.gov.au/resource/Enhancing/ResourcesTaxation/PetroleumResourRentTax/Pages/default.aspx>.

<sup>28</sup> See <https://www.gov.uk/hmrc-internal-manuals/oil-taxation-manual>.

**Gross Revenues:** The Gross Revenues ( $GR_t$ ) per year arising out of hydrocarbon sales is the product of the average annual oil price ( $(P_t)$ ) and the yearly production rate ( $(Q_t)$ ) for all fields. Oil here refers to the cumulative oil, gas and condensate production in barrels of oil equivalent (boe).

$$GR_t = \sum_{i=1}^T P_i Q_i \quad (3)$$

**Royalty:** The royalty which is taken as a percentage of the gross revenues and are tax-deductible:

$$ROY_t = \tau \times GR_t \quad (4)$$

Royalty tax rate falls between  $0 \leq \tau \leq 12.5\%$  in Ghana's petroleum agreements. Details are provided in Sect. 2.3.5.

**Costs:** These are the total costs for each field which comprises of exploration and appraisal costs, development costs, operating costs and decommissioning costs. It is given as:

$$\text{Total Cost} = \sum (\text{EA Costs} + \text{Devex} + \text{Opex} + \text{Aband}) \quad (5)$$

**Tax:** The income tax base is computed by taking the total revenue ceiling (the investor's share of the post royalty revenues) and deducting the following: finance costs (loan interest), recoverable costs (depreciated capital costs, depreciated exploration and appraisal costs, operating costs and decommissioning costs) and any prior period losses carried forward.

**Additional Oil Entitlement:** The State at any time is entitled to a portion of Contractor's share of crude oil from each separate Development and Production Area. The Additional Oil Entitlement (AOE) is levied on the basis of the after-tax inflation-adjusted rate of return (ROR) which the Contractor has achieved with respect to such Development and Production Area at the time in question. The ROR is calculated on a sliding scale as a resource rent tax in accordance with the following computation:

$$NCF_t = GR_t - ROY_t - COSTS_t - TAX_t \quad (6)$$

$$FA_t = FA_{t-1}(1 + r) + NCF_t \quad (7)$$

$$SA_t = SA_{t-1}(1 + r) + NCF_t - \delta FA_t \quad (8)$$

$$TA_t = SA_{t-1}(1 + r) + NCF_t - \gamma SA_t - \delta FA_t \quad (9)$$

$$YA_t = YA_{t-1}(1 + r) + NCF_t - \tau TA_t - \gamma SA_t - \delta FA_t \quad (10)$$

$$ZA_t = ZA_{t-1}(1 + r) + NCF_t - \beta YA_t - \tau TA_t - \gamma SA_t - \delta FA_t \quad (11)$$

where  $NCF_t$  is the net cash flow,  $GR_t$  gross revenues,  $ROY_t$  royalty paid,  $COSTS_t$  total recoverable costs,  $TAX_t$  income tax paid,  $FA_t$  first account,  $SA_t$  second account,  $TA_t$  third account,  $YA_t$  fourth account,  $ZA_t$  fifth account,  $r$  compounded internal rate of return and  $\gamma, \tau, \delta, \beta$  applicable additional oil entitlement charges.

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