WP/21/02

ATI Working Paper

Comparative Fiscal Regimes of the Oil and Gas Sectors in Ghana, the United Kingdom, Norway, Canada and Nigeria

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ABSTRACT

This paper reviews fiscal regimes of the oil and gas sector in Ghana vis-à-vis what pertains in comparative countries, namely the United Kingdom, Norway, Canada and Nigeria. The issues discussed are taxes imposed and contained in the legislation that regulates the oil and gas sectors in these countries. The paper is aimed at examining what lessons Ghana can learn from these countries, having joined the league of oil and gas producing countries. The main findings in this paper are that Ghana can revise its fiscal regime to enable the country to earn more revenue for its growth and development. Ghana can also improve on the stability of its fiscal regime with lessons from Canada and Norway, which will enhance certainty in its fiscal regime in the oil and gas sector. Ghana combines the contractual and concessionary systems to give the country the best of both systems. It is recommended in this paper that in assessing a fiscal regime, the tax rate should not be the only indicator in determining the effectiveness or otherwise of that fiscal regime. Other factors, such as the nature and extent of incentives provided to investors, have to be taken into consideration.

Key words: fiscal regime, oil and gas exploration and production, royalties, taxation, legislative instruments, legal and regulatory framework, tax laws.
JEL Codes: H2, H25, H26, K2, K4, K34

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1. Introduction

The announcement of oil discovery in commercial quantities in 2007 heightened expectations of the government and people of Ghana that the country was going to attain increased economic growth and development (CEPA, 2012). This optimism was based on the expectation that taxation on oil and gas would yield revenues in considerable amounts. This expectation was also corroborated by the International Monetary Fund (IMF). The IMF estimated that Ghana would earn about USD 20 billion between 2012 and 2030 (World Bank, 2009; Gary, 2010). According to CEPA (2012) and Ackah, Mochiah, Morrissey and Osei (2013), the estimated quantities and exports of oil from Ghana's Jubilee Field were expected to make Ghana a net exporter of oil from the year 2011, hence an expectation to generate an exportable surplus of at least USD 1.0 billion per annum between 2011 and 2015. This excluded projection of discoveries to be made of other oil wells for the next thirty years. Oil production was projected to increase from 106,900 barrels per day in 2011 to 120,500 barrels per day in 2015, after which output would then decline from the year 2016 to 2017 (CEPA, 2012; Bondzie, Bartolomeo and Fosu, 2014).

According to the World Bank Country Report (2009), the government revenue expected from the Jubilee Oilfields was USD 899.1 million in 2011. This was expected to increase consistently year-on-year until it reached a peak of USD 1,804.1 million in 2016, before declining steadily to a low amount of USD 429.1 million in 2029. However, actual petroleum receipts in the years 2016 and 2017 from the Jubilee Field revealed that the expected government revenue, as indicated in the World Bank Country Report, was not attained. Government revenue expected was USD 1,804.1 million as against actual receipts of USD 247.18 million in 2016, showing a variance of USD 1,556.92 million (86%). A shortfall again occurred in 2017, where the government revenue expected was USD 1,587.00 million whereas actual receipts were USD 540.41 million, showing a variance of USD 1,046.99 million (66%) as reported by the PIAC Annual Report (2016 and 2017) and the Ministry of Finance (2018). The variance recorded over the period supports that the high expectation from the oil and gas discovery and production has been thwarted.

In respect to this, the paper draws on the oil and gas sector legal framework and literature of selected countries, to evaluate the main challenges facing their fiscal regimes and to proffer policy options for Ghana going forward. The primary aim of the paper is to assess whether

Ghana is achieving the balance between the government's objectives of maximising tax revenue generation against the need to attract investments into the sector. In this light, the paper reviews four different countries that have established petroleum fiscal regimes. The countries are the United Kingdom, Norway, Canada and Nigeria. These are then compared with the fiscal regime of Ghana.

The countries were selected based on the following factors. With the exception of Norway, the remaining countries belong to the Commonwealth of Nations, as does Ghana, and thus have some commonalities in respect of their tax regimes. For instance, tax cases in court are resolved with references to these Commonwealth countries (Wijnen, 2013). Moreover, Ghana's tax regime is similar to that of the United Kingdom.

The United Kingdom, Norway, Canada and Nigeria have long histories of oil and gas exploration and production, and hence have established and/or possibly put in place more mature systems in the extraction, governance and accountability of their oil and gas resources relative to Ghana. Of particular importance is the comparative assessment of the fiscal regimes of Nigeria and Ghana, two Sub-Saharan African countries with very diverse oil sectors, but also with some striking commonalities. Nigeria's regime is studied because the country is a mature oil-producing nation, and its oil industry is one of the oldest in Sub-Saharan Africa with possible lessons for Ghana. The United Kingdom and Norway are two mature oil-producing countries with strong common historical interests in hydrocarbon exploration along the North Sea continental shelf. The long history of petroleum exploration and production by the two states makes a comparison of their fiscal regimes and revenue management standards pertinent for frontier Ghana. The UK North Sea is particularly important due to the lessons that may be learnt from the history of its fiscal regime, as one of the world's most unstable and frequently altered regimes. Also, it is generally relevant and applicable to oil production world-wide, because experiences can be shared on how and when to alter the fiscal regime.

The paper aims to answer the question whether Ghana's tax regime for the oil and gas sector could be guided by lessons from comparative fiscal regimes in the United Kingdom, Canada, Norway and Nigeria. Although the paper presents a broader world view of oil and gas fiscal regimes across the selected jurisdictions, it places a premium particularly on comparative law and policy issues of taxation. The underlying question examined in this paper is: what lessons can Ghana learn from the fiscal regimes of these selected countries? The comparative study of fiscal regimes in oil producing countries generally tends to focus on the broader theory and practice of comparative tax law scholarship. The case of the selected countries is not any different. To set the tone for the discussion, however, it is significant to attempt to put into historical context the legal character of the fiscal regimes in each of the selected countries. Hence, in comparing the fiscal regimes, the study acknowledges that the tax system in each of the selected jurisdictions is deeply rooted in their particular culture, history and socio-political *milieu*.

The remainder of the paper is structured as follows. To support comparative analysis, Section 2 provides reviews of the legal framework, and fiscal regimes in the oil and gas sectors of Ghana, the United Kingdom, Canada, Norway and Nigeria. Section 3 synthesises the major fiscal regimes to determine different characteristics that influence the design of tax policy and laws in the oil and gas sectors in these countries. The final section concludes and provides recommendations for policy makers in the oil and gas sector.

2. Fiscal Regimes

A fiscal regime is regarded as the set of instruments or tools that determine how the revenues from oil and gas projects are shared between the state and companies (NRGI, 2015). The tools refer to taxes, royalties, dividends, production sharing, bonuses, and so on; that is, the legal framework of a country that captures the details of the fiscal tools employed in a country. These are examined below for the countries under study in this paper.

2.1 Ghana's Fiscal Regime

In 2007, Ghana joined the ranks of oil-rich countries in the Gulf of Guinea, when oil exploration companies discovered proven oil reserves in commercial quantities in the Jubilee Field, off the Cape Three Points along its western coast. Ghana's oil reserves, which are estimated to be between 600 million and 1.8 billion barrels, have been termed "the largest discovery in West Africa in more than a decade" (Gary, 2010; Skaten, 2018). Ghana's production of crude oil is expected to reach half a million barrels by 2024, which, for a country of about 30.42 million people with a *per capita* GDP of about USD 1,950 in the first quarter of 2019, expected to be USD2,100 in 2020, is substantial (Ministry of Finance, 2019). Characteristic of oil from the Gulf of Guinea region, its reserves are of high quality - it is light and sweet. Crude oils of this type attract a wide range of refiners and can be expected to command competitive prices in the market (Tullow PLC, 2010).

The Ghanaian Government enacted two important legislative instruments to promote transparency and accountability in the taxation of its oil. These are the Income Tax Act, 2015 (Act 896), with its Gazette notification dated 18 February 2016, and the Petroleum (Exploration and Production) Act, 2016 (Act 919), with its Gazette notification dated 19 August 2016.

The taxation of petroleum operations from 2016 is governed by the provisions in Part VI, Division I of the Income Tax Act, 2015 (Act 896). The significant provisions introduced include the taxation of dividends in the petroleum sector under Section 71(2), which provision hitherto did not exist. It also provides under Section 69 that a person is treated as having disposed of his or her petroleum interest when there is a change in the underlying ownership by five per cent or more. The consideration obtained is thus subject to tax; hence this provision secures revenue for the Government of Ghana.

The Income Tax Act, 2015 (Act 896) again provides, under Section 66(1)(d), for the taxation of a gain from the assignment or other disposal of an interest in the petroleum right, which is a significant provision to secure a hitherto revenue loss under the Petroleum Income Tax Law, 1987, where an assignment of interest led to a deferred tax revenue to the state. This provision now provides the Government of Ghana with an instant revenue inflow rather than a deferred one.

Another positive provision is found in Section 70 of the Income Tax Act, 2015 (Act 896), which provides for petroleum operators to establish a decommissioning fund into which contributions would be made by the operators. The purpose of the fund is to ensure that petroleum operators can decommission their petroleum operations and address any environment damage that they may cause during their operations. Contributions to the fund are exempt from tax, whereas any surplus remaining in the fund would be subject to tax after the decommissioning.

Despite the above positive provisions in the Income Tax Act, 2015 (Act 896) to secure revenue to the state, the provision in Section 66(10)(g), which mentions that any amount derived which is incidental to the operation of the petroleum operator, and which should be added to the operator’s income, is inimical to revenue mobilisation from the petroleum sector. The phrase "incidental to" does not engender certainty because how does one determine what is "incidental to"? There is the need for clarity to ensure certainty in the revenue inflows.

Fiscal provisions in the Petroleum (Exploration and Production) Act, 2016 (Act 919) are found in Sections 85, 86, 87, 88 and 89 and address the issues of payment of royalties and an annual fee in respect of acreage, tax, bonus payments and additional oil entitlement respectively. This study is primarily concerned with Section 85 on the payment of royalties, Section 87 on tax and Section 88 on bonus payments.

Section 85(1) of the Petroleum (Exploration and Production) Act, 2016 (Act 919) provides that the contractor shall pay a royalty to the Republic of Ghana in respect of the gross volume of petroleum produced and saved. Of concern here is the discretion given the minister responsible for petroleum under Section 85(3) to direct, in writing, for the royalty to be paid in cash other than in kind, as provided in the same section. This is too wide a discretion because there is no provision requiring the minister to seek the approval of Parliament in this regard. This concern is anchored in the provision of Article 174 of the 1992 Constitution of Ghana, which states:

> (1) No taxation shall be imposed otherwise than by or under the authority of an Act of Parliament.
>
> (2) Where an Act, enacted in accordance with Clause (1) of this article, confers power on any person or authority to waive or vary a tax imposed by that Act, the exercise of the power of waiver or variation, in favour of any person or authority, shall be subject to the prior approval of Parliament by resolution.
>
> (3) Parliament may by resolution, supported by the votes of not less than two-thirds of all members of Parliament, exempt the exercise of any power from the provisions of clause (2) of this article.

It is evident from Article 174(2) that the minister has the power to vary a tax, though this requires the prior approval of Parliament. Indeed, under Article 174(3), Parliament may waive the requirement in Article 174(2), requiring the minister to seek Parliament's prior approval but even then, it must be supported by the votes of not less than two thirds of all members of Parliament. The question is how secure are the revenue inflows if this discretionary power is abused or misapplied?

Under Section 87 of the Petroleum (Exploration and Production) Act, 2016 (Act 919), a licensee, contractor, sub-contractor and the Ghana National Petroleum Corporation are required to pay taxes, including petroleum income tax and capital gains tax, in accordance with applicable enactments. Given the provision of stability clauses in almost all the petroleum agreements before the coming into force of Act 919, one may ask what can be salvaged in terms of revenue from petroleum? Especially so when Article 12.1 of these petroleum agreements before 2013 bars the Government of Ghana from going after taxes that are not covered in the petroleum agreement. This study submits that the horses may have bolted before there was thought of locking the gates to the stables; Ghana has lost some revenue before safeguards against revenue loss from the petroleum sector were considered.

Section 88 on bonus payments begs the same questions posed in respect of Section 87 on tax. The additional question is: how many more oil and gas discoveries are being anticipated for the bonus payment to apply? Moreover, the provision is shrouded in uncertainty when it states that a contractor shall pay a bonus to the Republic of Ghana as may be prescribed. Is it then not possible to prescribe the bonus payment in the law to ensure certainty? The provision continues to state that where the type and the quantum of the bonus are not prescribed, the bonus shall be paid as otherwise provided in accordance with the terms of a petroleum agreement. How secure is Ghana in earning revenue from bonus payments that will be provided in an agreement that is subject to negotiation? Does the Government of Ghana have the capacity and resource specialists to negotiate such terms?

The fiscal provisions in the petroleum agreements are found in Article 12 of the agreements. There has been a significant improvement in the effectiveness of the provisions. It is positive for Ghana that steps have been taken to prevent the loss of revenue that hitherto was occasioned by the provisions in the earlier agreements signed prior to 2013. Whereas the earlier agreements pre-dating 2013 provided a kind of fiscal enclave for the international oil companies, such that owing to the stability clauses, no changes in fiscal legislation could affect them, the agreements after 2013 did not create such an enclave. Unfortunately, no challenge of the pre-2013 oil and gas agreements in the courts has ever occurred, hence the issue of its provisions overriding the laws of Ghana has not yet been tested in the courts.

Contrary to the earlier agreements, the petroleum agreements signed in the year 2013 (that is the Petroleum Agreement amongst the Government of the Republic of Ghana, the Ghana National Petroleum Corporation, the GNPC Exploration and Production Company Limited and the AGM Petroleum Ghana Limited in respect of the South Deepwater Tano Contract Area dated 10th September 2013; and the Petroleum Agreement amongst the Government of the Republic of Ghana, the Ghana National Petroleum Corporation, COLA Natural Resources and MEDEA Development Limited in respect of the East Cape Three Points Contract Area of September, 2013) have specific provisions governing the fiscal regime.

Article 12.1 provides as follows:

> Subject to applicable laws and regulations as the same may be amended from time to time, the tax, duty, fee and other imposts that shall be imposed by the state or any entity or any political subdivision on contractor, its sub-contractors or its affiliates in respect of works and services related to petroleum operations and the sale and export of petroleum shall include but not be limited to the following.

This is, indeed, a marked departure from the earlier agreements based upon the model petroleum agreement, which sought to create a fiscal enclave by restricting the taxes applicable to the petroleum sector to only the taxes stated in Article 12. From the above rendition, it means that petroleum operators may be subject to changes in the fiscal regime in Ghana from time to time.

The following taxes are then provided for in Article 12.1:

a. Corporate income tax at the rate of 35 per cent with the chargeable income being calculated in accordance with the Petroleum Income Tax Act, 1987 (P.N.D.C.L.188);
b. The vexing issue of taxation of assignment of interest is also now addressed more clearly as follows:

Notwithstanding Article 12.1(a), a tax in respect of income and/or gain (in either case, calculated in accordance with Ghanaian law) resulting from the direct or indirect sale, transfer or assignment of:

(i) a partial or the entire interest in this agreement;
(ii) assets acquired or used in petroleum operations under this agreement; or

(iii) shares of contractor,

at the rate determined by Ghanaian law in effect at the time of the sale, transfer or assignment.

In as much as an attempt is made here to address the issue, the uncertainty still remains when the rate of tax applicable is not stated but left to the Ghanaian law in effect at the time of the sale, transfer or assignment. It is rather better now, as the Income Tax Act, 2015 (Act 896) in Section 66(1)(d) provides that "a gain from the assignment or other disposal of an interest in the petroleum right with respect to which the operation is conducted" shall be included in the income of a person from petroleum operations and taxed. In this way, one is certain that since the corporate income tax rate is 35 per cent, then that is what will be applicable to the gains arising out of an assignment of an interest or a part thereof.

Article 12.1 also makes provision for:

c. Payments for rental of government property, public lands or for the provision of specific services requested by the contractor from public enterprises; provided, however, that the rates charged to the contractor for such rentals or services shall not exceed the prevailing rates charged to other members of the public who receive similar services or rentals.
d. Surface rentals are also payable by the contractor to the state, and it varies as per agreement, and is calculated per square kilometre of the contract area remaining at the beginning of each contract year as part of the contract area, in the amounts as set forth below:

Phase of Operation	**Surface Rentals per Annum**
Initial Exploration Period	USD 50 per sq. km.
1st Extension Period	USD 100 per sq. km.
2nd Extension Period	USD 100 per sq. km.
Development & Production Area	USD 200 per sq. km.

It is noteworthy that these rentals shall be pro-rated where the beginning of a period and the end of a period or the creation of a development and production area occurs during the course of a calendar year.

Under Article 12.2 of the agreement in respect of the East Cape Three Points Contract Area, the following is provided:

Save for withholding tax at the rate provided for under applicable law from the aggregate amount due to a resident sub-contractor or non-resident sub-contractor, the contractor shall not be obliged to withhold any tax in respect of tax from any sum due from the contractor to any sub-contractor in respect of work and services for or in connection with this agreement.

In respect of the South Deepwater Tano Contract Area, the following addition is included: "Notwithstanding the foregoing, the withholding of tax in respect of services provided to the contractor by an affiliate of any company comprising the contractor shall be waived, provided such services are charged at cost".

The question remains as to how 'cost' will be determined, even more so in the ever-rising case of transfer pricing as a major concern in international taxation? This paper posits that this is another avenue for loss of revenue to the state that needs urgent attention. This apprehension is premised on the observation that most international oil companies have affiliates, associates and sub-contractors in which they hold shares, hence making it possible for costs to be uploaded amongst the parties, which practice will impact on profits. High upload of costs, which will be non-arm's length, can lead to low profits, or possible losses in related entities, hence low revenue to the government or none, if it is a loss position. The uploaded costs are then transferred to other associates outside Ghana, leading to transfer pricing abuse.

There is no application of indirect taxes on petroleum operations, either by way of import duties, export duties or VAT. It is provided that, subject to the local purchase obligations, the contractor and sub-contractors may import into Ghana all plant, equipment and materials to be used solely and exclusively in the conduct of petroleum operations, without payment of customs duties and taxes upon imports, save administrative fees and charges (Clauses 12.3 and 12.4 of the agreement in respect of the South Deepwater Tano Contract Area and the East Cape Three Points Contract Area respectively). The contractor shall not be liable for any export tax upon petroleum exported from Ghana, and no duty or other charge shall be levied on such exports. More so, vessels and other means of transport used in the export of contractors' petroleum from Ghana shall not be liable for any tax, duty or other charge, by reason of their use for that purpose. The contractor shall not be liable to pay VAT in respect of plant, equipment and materials, and related services supplied in Ghana, to be used solely and exclusively in the conduct of petroleum operations. Foreign national employees of contractors or their affiliates, and of their sub-contractors, shall be permitted to import into Ghana, free of import duty, their personal and household effects in accordance with Section 22.7 of the Ghana National Petroleum Corporation Law, 1983 (P.N.D.C.L. 64), with the provision that no property imported by such employee shall be resold by such employee in Ghana.

The above provisions are too sweeping to be incentives that seek to protect government revenue, as they rather narrow the tax base from which the state can earn tax revenue. The intent of the government could be premised on attracting investors into the oil and gas sector of the economy. Unfortunately, it has dire revenue loss consequences. The only provisos are that the Ghana National Petroleum Corporation (GNPC) shall have the right of first refusal for any item imported duty free, which is eventually later sold in Ghana, and it is only when the GNPC does not exercise its right of purchase that the contractor may sell to any other person. The authors do not find this a credible solution to such exemptions, since it leaves questions to be answered. The question that still begs an answer pertains to how all the duty-free purchases and imports would be monitored to ensure that revenue is not lost. This is all the more reason for the advocacy that the Income Tax Act should be the only legislation to provide for the effective and efficient taxation of petroleum operations, and not provisions in the agreements that forfeit too much to international oil companies who come in as contractors with affiliates and sub-contractors.

The Minister of Energy is required to issue guidelines for contractors to make contributions to a decommissioning fund on estimated costs of abandonments in proportion to their participating interest. Such contributions shall be allowed as a deduction from the assessable income for the year of assessment in which the contributions commenced. In the year of assessment in which the decommission has been completed, in accordance with an approved decommission plan, the surplus funds shall be treated as chargeable income and subject to tax. Any amount remaining thereafter shall be subject to an additional oil entitlement at the highest rate at which the contractor paid Additional Oil Entitlement (AOE) during the period of contributions to the relevant decommissioning fund. Any surplus thereafter shall revert to the contractor.

This is a laudable provision that should raise revenue for the state, but the now-familiar question applies again: how is this going to be monitored to ensure transparency and accountability? This will ensure the protection and resuscitation of the environment, since the policy rationale behind the provision for a decommissioning fund is to enable the international oil companies to raise funds internally from their profits to do so. This policy is thus not a revenue generation measure by the Government of Ghana, but a policy direction to secure and protect the country against environmental degradation occasioned by oil and gas production activities in Ghana.

Ghana's fiscal regime in the oil and gas sector is a hybrid system of production sharing and a concessionary regime, which governs the contractual arrangements with the international oil companies (IOCs) in the upstream production (Amoako-Tuffour and Owusu-Ayim, 2010). Under the Production Sharing Contracts (PSC), the international oil companies (IOCs) pay the Government of Ghana royalties on gross production. The IOCs are allowed a pre-determined share of production for the recovery of their costs of investment in exploration, referred to as cost oil, after which the remainder, which is known as profit oil, is shared between the IOCs and the Government of Ghana on agreed terms. The IOCs are, thereafter, also required to pay tax on their share of profit. The IOCs, under the concessionary system, are to bear all costs and risks associated with the exploration and development of the oil blocks. Ghana's adoption of the hybrid system means that the best aspects of the PSC and also of the concessionary system have been combined to ensure that the country receives the best advantage of both systems. The fiscal terms of the oil and gas sector are found in the various petroleum agreements signed between the Government of Ghana and the IOCs.

2.2 The United Kingdom's Fiscal Regimes

The nature and character of the petroleum fiscal regime originates from a July 1974 Labour Government White Paper, entitled "United Kingdom Offshore Oil and Gas Policy". The principles espoused in the White Paper were later formally legislated through the Oil Taxation Act of 1975, which unusually stressed private involvement, rather than state monopoly of the industry. The fiscal regime required the following three main tax instruments: (1) royalty; (2) petroleum revenue tax (PRT) and (3) corporation tax (CT).

Prior to 1975, there were two elements to the United Kingdom North Sea fiscal regime: a royalty charged at 12.5 per cent and corporation tax charged at 50 per cent. The required royalty of 12.5 per cent was charged on a half-yearly basis and fixed on the gross revenues of each field with a deduction for conveying and treating costs, which represents the cost of bringing the petroleum ashore and its initial treatment. Subsequent developments saw the abolition, in 1983, of the royalty on fields that received development consent after 1983. The royalty regime was abolished subsequently, between the fourth quarter of 2002 and the first quarter of 2003.

The 1975 regime varied from the pre-1975 corporate tax rate of 50 per cent upwards to an initial 52 per cent on company net profits, which was the uniform rate applicable to all categories of industries in the United Kingdom. Both exploration and development costs were deemed deductible, except that exploration costs were fully deductible at the time expended, while development costs were made subject to various tax depreciation allowances. Contrary to normal company corporate tax applications, a company engaged in petroleum operations in the United Kingdom's continental shelf is subject to a ring fence arrangement. Consequently, a company could neither use its losses from other activities to reduce the profits originating from within this continental shelf ring fence, nor set losses and capital allowances inside the ring fence against income arising outside the ring fence. The exception is that losses and capital allowances inside the ring fence may be set against income arising outside the ring fence.

By the end of 1986, the broader requirements of the United Kingdom industry influenced a sharp reduction of corporate tax that applied on oil activity in the North Sea to 35 per cent (Nakhle, 2010; Riley and Chate, 2014). Further reforms took place in 2002 when a 10 per cent supplementary charge on profits subject to corporate tax was introduced to be calculated on the same basis as normal corporate tax, although deduction on financial costs was not guaranteed. A further 100 per cent capital investment allowance was introduced against both the corporate tax and the supplementary charge. Oil price volatilities and increase in public spending led the United Kingdom Government to increase the level of the supplementary charge by another 10 per cent.

In 2002, the United Kingdom Government introduced a 10 per cent supplementary charge on profits subject to corporate tax. This charge was calculated on the same basis as normal corporate tax, but there was no deduction for financing costs. Additionally, a 100 per cent capital investment allowance was introduced against both corporate tax and the supplementary charge, with effect from 1 January 2006.

In addition to royalties and corporate tax, which are pre-1975 elements, the Oil Taxation Act of 1975 introduced the Petroleum Revenue Tax (PRT) as an additional tax and sets out the main regulations governing the administration of petroleum taxation in the United Kingdom.

Consistent with the Oil Taxation Act of 1975, PRT was initially charged on a half-yearly basis at the rate of 45 per cent on the value of oil and gas produced. PRT is a special petroleum profits tax related to separate geological and technically determined fields assessed equally on a field-by-field basis under a "ring fence" arrangement (Nakhle, 2008; Tordo, Johnston and Johnston, 2009; Nakhle, 2010; Tordo, Tracy and Arfaa, 2011). The fundamental aim of introducing PRT was to capture economic rent from commercially viable and profitable fields, while shielding less profitable projects from tax burdens. To this extent, three major allowances/reliefs were introduced, namely: (1) uplift, (2) oil allowance and (3) safeguard. A good summary of the nature and purpose of these reliefs is that given by Nakhle (2008: 54) as follows:

> Uplift, which is an additional allowance of 75 per cent to capital expenditures (CAPEX), so companies will not start paying PRT until they have at least recovered 175 per cent of their CAPEX…Oil allowance, which allows one Mt of oil per annum to be exempt from PRT up to a cumulative maximum of ten Mt. As a result, PRT is unlikely to be payable on fields with reserves of less than 100 mmbbls. The oil allowance was introduced to help the development of marginal fields…Safeguard, which limits the PRT liability in any chargeable period to 80 per cent of the amount by which cumulative gross profit exceeds 15 per cent of cumulative expenditure. Safeguard was introduced to ensure that, while it applies, PRT – calculated after taking account of all other reliefs – does not reduce a participator's return on capital in any chargeable period to 15 per cent or less. As such, the safeguard limits PRT liability for a part of the field's life and allows fields to achieve a certain level of return on investment before they incur any PRT liability.

In 1978, the United Kingdom Government tightened up the PRT to 60 per cent to increase its level of total tax take when oil prices increased. Other measures taken by the government include reducing the uplift allowance to 35 per cent, as well as reducing the oil allowance from one Mt to 500,000 tonne per year, with a maximum allowance of 5 Mt. While further upward adjustment in the rate of PRT occurred in 1980 to 70 per cent, the tax was drastically reduced to 50 per cent on existing fields and abolished on all fields receiving development consent after April 1993. Incentives for exploration and appraisal drilling were also removed at the same time in 1993. The

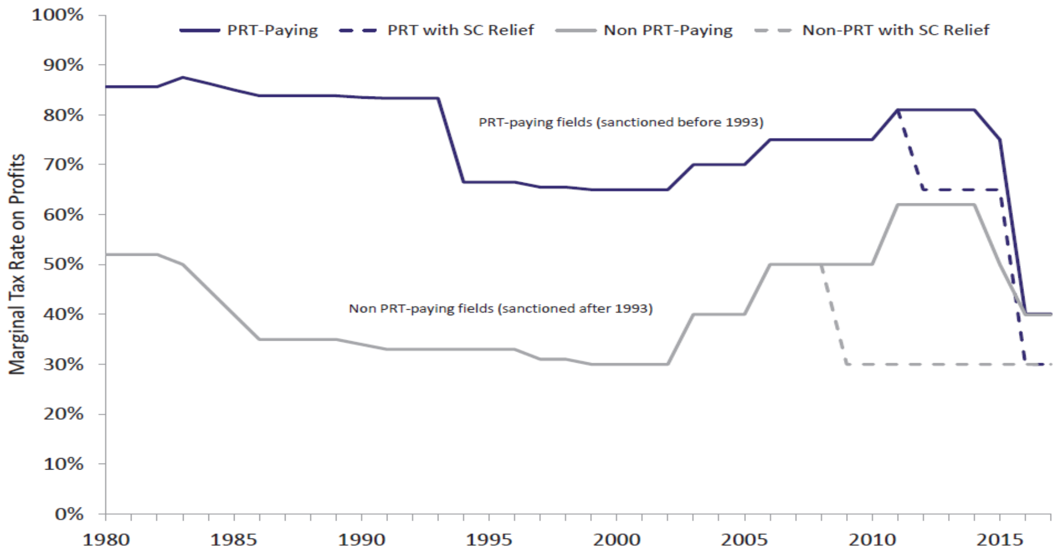
PRT was thus effectively abolished (Zhang, 1997; Nakhle, 2008; Kemp, 2013; Kemp and Stephen, 2016).

The United Kingdom petroleum fiscal regime remains volatile as its structure keeps changing. As of June 2014, the fiscal regime comprised two elements: (1) “ring fence” corporation tax (RFCT), and (2) supplementary tax and PRT (HMRC, 2014). The “ring fence” corporation tax is calculated the same way as the standard corporation tax, applicable to all companies but with the addition of a “ring fence” and the availability of 100 per cent first year allowances for virtually all capital expenditure. The ring fence prevents taxable profits from oil and gas extraction in the UK and its North Sea petroleum activities from being reduced by losses from other activities or by excessive interest payments. The rate of tax on ring fence profits, which is set separately from the rate of mainstream corporation tax, was 30 per cent. The Supplementary Charge is an additional charge, which stood at a rate of 32 per cent (increased from 20 per cent from 24th March 2011), on a company’s ring fence profits (but with no deduction for finance costs). A “field allowance” removes from the charge to supplementary charge a slice of production income from qualifying small or technically challenging new fields.

Finally, the rate of PRT, which is a field-based tax charged on profits arising from oil and gas production from individual oil and gas fields given development consent before 16 March 1993, stood at 50 per cent. The year 2016 saw a reduction in the number of taxes paid by United Kingdom continental shelf fields from three to two. Much of PRT was proposed to be abolished by the Chancellor in the March 2016 Budget – the PRT having been permanently zero-rated from 1 January 2016 with supplementary charges reduced to 10 per cent from the 2015 rate of 20 per cent (O&G UK, 2016).

Further reductions to the Supplementary Charge in 2016 reduced the headline rate of tax paid on United Kingdom oil and gas production from 50 -75 per cent to a flat rate of 40 per cent across all fields (Kemp and Stephen, 2016). The United Kingdom petroleum fiscal regime is now made up of two taxes: (1) Ring Fence Corporation Tax (RFCT) and (ii) Supplementary Charge (SC). RFCT is a tax on company profits computed in a similar way to normal CT, but levied at a higher rate of 30 per cent. It is currently 50 per cent higher than the 20 per cent CT rate applicable to the rest of the UK between 2016 and 2017. There is, however, a 100 per cent first year capital allowance as well as some enhanced loss flexibilities to reflect the high levels of investment and project life cycles typical of the UK continental shelf (O&G UK, 2016).

Figure 1 Historic Upstream Tax Rates in the United Kingdom



Source: O&G UK (2016: 77)

Conversely, SC is an additional layer of corporate taxation computed like RFCT, but finance costs are not deductible. The rate is chargeable at 10 per cent from 1 January 2016, having halved from 20 per cent in 2015 and 32 per cent before then (O&G UK, 2016).

Furthermore, while PRT has now been effectively abolished for income and profits, the tax remains relevant for the purposes of generating tax relief on future losses, especially arising from decommissioning. PRT paid by a field in the past is refundable on a last in, first out (LIFO) basis at the rate of tax levied on profits in the respective period.

Similar reforms were made in the 2015 Budget, which transformed and simplified the tax allowance regime by moving away from bespoke Field Allowances, which have been replaced with the Investment Allowance. O&G UK (2016) summarises the important features of the current allowance regime as follows:

(i) The Investment Allowance (IA) – this is a basin-wide capital investment-based allowance against a company's SC liability. It is available for all capital investment incurred on or after 1 April 2015 at a rate of 62.5 per cent. If a company has access to the allowance, only RFCT will be levied on its profits, reducing the effective tax rate to 30 per cent; and

(ii) 100 per cent first year Capital Allowances – for almost all investment expenditure incurred on the UK continental shelf, an immediate deduction against RFCT and SC is available within the year, making the regime a true cash-flow tax.

Additionally, current reforms permit any of a company's expenditure (whether capital or operating) that cannot be relieved in the year it was incurred to be carried forward for an unlimited period until the company returns to having taxable profits. Similarly, a company can claim up to ten instances of Ring Fence Expenditure Supplement (RFES) that enhances the cash value of the loss by 10 per cent per period claimed (O&G UK, 2016).

2.3 Norway's Fiscal Regime

The foundation of the Norwegian petroleum fiscal regime is in the Taxation of Subsea Petroleum Resources Act of 1965, Section 2, which requires the application of the general rules of taxation to petroleum activities. Considering that the Norwegian continental shelf was a frontier province with uncertain prospects at the time, the Taxation of Subsea Petroleum Resources Act of 1965 introduced tax reliefs in the form of reduced rates to increase the competitiveness of the province and to give it a comparative advantage over that of the North Sea concessions under the jurisdiction of neighbouring countries. This facilitated a massive exploration programme, leading to the discovery of the first commercial field (Ekofisk Field) in 1969. During this period, royalty was applied at a 10 per cent flat rate.

Subsequent discoveries and commencement of production in 1971 effectively de-risked the Norwegian continental shelf and served as the basis for revision of the fiscal regime in 1972 in favour of increased government take. The privileges under the 1965 Tax Act were abolished, and the industry paid taxes on the same basis as other Norwegian business enterprises for the next four years. The royalty rate was however revised to a range between 8 to 16 per cent applied on a sliding scale (depending on production). In 1975, however, external market pressures arising partly from significant increases in oil prices led the Norwegian Government to reconsider the fiscal regime. An expert committee was established in this regard, which proposed the enactment of a new Petroleum Tax Act to replace the 1972 revised regime. The resultant Petroleum Tax Act introduced (i) the Special Tax, and (ii) the Norm Price system for determining the tax value of crude oil produced. The rate of Special Tax was set at 25 per cent, giving a marginal tax rate in the range of 76 per cent. Uplift was introduced as a relief against the Special Tax, with 10 per cent of cost price of production and pipeline installations over 15 years (Bustneshi, 2018). To avoid transfer pricing issues on sales between related companies, the new act also required crude oil sales to be valued at Norm Price, an administratively fixed price (Bradley and Mead, 1998; Readhead, 2018).

In 1980, due to oil price increases, the Special Tax rate was increased from 25 per cent to 35 per cent, only to be reduced to 30 per cent in the mid-1980s in reaction to decreasing oil prices at the time (Berger, Cappelen, Knudsen and Roland, 1988; IMF, 2000). Depreciation was accelerated (allowing it to commence in the year of investment, rather than when the asset was taken into use), while a production allowance was introduced to replace uplift for new projects (Osmundsen *et al.*, 2014). Major reforms also took place in 1987 (the royalty was further abolished for all fields receiving development approval from 1 January 1986), 1992, 2000 through 2005 to 2007, all intended to secure a fair share of the economic rent while incentivising investors to inject capital into the Norwegian continental shelf (Tordo *et al*., 2011).

Lund (2014) posits that the Norwegian petroleum fiscal regime is based mainly on corporate income tax (CIT) and special petroleum tax (SPT). While CIT applied at a rate of 28 per cent as of 2008 down from the 1992 rate of 50.8 per cent – which was the general income tax that applied to all companies operating in Norway - SPT applied to offshore production income at 50 per cent (Nakhle, 2008). The Norwegian SPT, unlike PRT in the UK, is not deductible for CIT purposes. Furthermore, depreciation for capital expenditures is allowed on a six-year straight-line basis, for both CIT and SPT purposes (Nakhle, 2008). This effectively equates SPT deductions and depreciation when dealing with CIT, except that an additional uplift applies in the case of SPT. Similarly, for all fields approved before 1986, while the SPT uplift is an extra 100 per cent on expenditures incurred for each asset used in production and pipeline transportation, a rate of 5 per cent over six years applies to fields whose development plan was accepted after 1 January 1986 (Nakhle, 2008).

While allowing at most 50 per cent losses from operations on the Norwegian continental shelf to be offset against profits from producing fields, the Norwegian fiscal regime requires the application of the ring fence principle in calculating SPT (Daniel, Keen and McPherson, 2010; Osmundsen *et al.*, 2014). Additionally, both the SPT and CIT allow losses to be carried forward, implying that no tax is paid unless all losses have been absorbed (Lund, 2014). The fiscal regime also allows the deduction of abandonment costs at a rate equal only to the effective tax rate (Tordo, 2007; Lund, 2014). Finally, the Norwegian fiscal regime allows for losses from operations on the Norwegian continental shelf to be offset against profits from producing fields (Noord and Vourc'h, 1999; Alnæs and Haugland, 2017).

2.4 Canada's Fiscal Regime

Petroleum exploration activities in Canada date back to 1850, when the geologist, Thomas Sterry Hunt of the Geological Survey of Canada reported seepages of crude oil in the swampy "gum beds" of Enniskillen Township, Lambton County, Ontario (CCEI, 2004). Since then, exploration activities steadily increased, pioneered by the International Mining and Manufacturing Company – the first registered oil company in North America. By 1858, a year before 'Colonel' Edwin Drake found a practical way to produce large quantities of crude oil in Pennsylvania in the United States, the International Mining and Manufacturing Company, owned by James Miller Williams, was reportedly producing and refining significant quantities of crude oil from its 15-metre-deep well in Petrolia (CCEI, 2004). It has been strongly canvassed by Canadian scholars and industry practitioners that crude oil was already being produced from wells in Ontario several years before the emergence of the modern petroleum industry following 'Colonel' Drake's 1859 discovery in the United States (CCEI, 2004).

The nature and character of Canada's petroleum fiscal regime is deeply rooted in the governance structure of the country. Given that Canada is a federal state, ownership of natural resource rights is held partly by the provinces, but largely by the Crown/federal government (Plourde, 2010). A classic example can be found in the western Canadian province of British Columbia. The Crown owns almost 100 per cent of producing oil and gas rights (CNWP, 2011). Similarly, in the Yukon, the Crown owns the majority of subsurface rights. Again, in the Northwest Territories and Nunavut, as well as the northern offshore, the federal government is the owner of the majority of petroleum and natural gas resource rights. In other provinces such as Alberta and

Saskatchewan, the province owns approximately 80 per cent of petroleum and natural gas resource rights; the remaining rights are classified as "freehold rights" (Taylor *et al*., 2004; CNWP, 2011). Freehold rights are rights owned by private individuals or companies. As such, depending on the area of exploration, royalties fall under provincial, or territorial or federal jurisdictions (Martin, 1975; Gault, 1985; CNWP, 2011). With the exception of the Yukon, natural resources in areas that are not provinces or not subject to special agreement (e.g. the Atlantic Accord and the Canada-Nova Scotia Offshore Accord) fall under federal jurisdiction (Hudec and Penick, 2003; Studin, 2009; CNWP, 2011). Federal royalties apply to these Crown lands, categorised as 'frontier' and 'reserve' lands.

Royalties on frontier lands are prescribed under the Canada Petroleum Resources Act (CPRA), while those on reserve lands come under the Indian Oil and Gas Act. Under the CPRA and the Frontier Lands Petroleum Royalty Regulations (FLPRR), the royalty applicable to oil and natural gas consists of a 1 per cent royalty on gross revenue at start-up, increasing by 1 per cent every 18 production months to a maximum of 5 per cent or until payout is reached (Holroyd and Dagg, 2011). After payout, the royalty is calculated at the greater of 30 per cent of net profit (gross revenue – allowed operating costs - allowed capital costs = net profit) or 5 per cent of gross revenues (Watkins, 2001; Mintz and Chen, 2012; Dobson, 2015). The frontier lands royalty regime permits operating and capital costs to receive 10 per cent and 1 per cent uplifts respectively, after project commencement to recognise indirect expenses (CNWP, 2011; Cameron and Stanley, 2017). Where allowed capital costs are incurred before a project commences, it receives an uplift based on the inflation index. In what is termed an Investment Royalty Credit, any un-recovered costs (prior to royalty payout) are given a return allowance equal to the long-term government bond rate plus 10 per cent (CNWP, 2011; Mintz and Chen, 2012; Tordo, 2017). Royalty payout is said to be attained when cumulative gross revenues exceed cumulative operating costs, capital costs, gross royalties paid and a return allowance (Watkins, 2001; CNWP, 2011; Boadway and Dachis, 2015; Shaffer, 2016). Payout is calculated on a working interest basis, by project. The Investment Royalty Credit was phased out through the 2008 amendments to the FLPRR, though some companies may continue to claim expenses incurred while the program was in effect (CNWP, 2011).

The royalty regime applicable to reserve lands is too varied to be studied, due primarily to a provision of the Indian Oil and Gas Act, which allows for a variation in the royalty payable by entering into a special agreement, usually with the consent of the Chief and Council of the respective native bands for which the particular reserve land was set apart (Wälde, 2008; CNWP, 2011). This has resulted in special royalty agreements for nearly all land dispositions since the mid-1980s.

Corporate income tax is another feature of the Canadian federal fiscal regime. The general federal corporate income tax rate was 16.5 per cent for 2011, reduced to 15 per cent for 2012 and subsequent years. Although capital tax and surtax for all corporations previously existed, these were abolished in 2006 and 2008 respectively (Chen and Mintz, 2011; CNWP, 2011; Hegemann, Kunoth, Rupp and Sureth-Sloane, 2016).

General deductions allowed to corporations include operating expenses, capital cost allowance, interest expense, resource expenses and general and administrative expenses, as well as Crown royalties. Provincial taxes, however, are not deductible. In the case of capital cost allowance, the regime provides, amongst others, a 25 per cent write off rate on a declining balance basis for oil and gas equipment (Ketchum, Lavigne and Plummer, 2001; Mintz, 2010; Siu, Picciotto, Mintz and Sawyerr, 2015). In the case of resource expenses, any of the following three groups of expenses, namely, (i) Canadian Exploration Expenses (CEE); (ii) Canadian Development Expenses (CDE); and (iii) Canadian Oil and Gas Property Expenses (COGPE), can be carried forward indefinitely.

According to the CNWP (2011), CEE (which can generally be deducted against income at up to 100 per cent of the balance) includes certain intangible costs incurred to determine the 'existence, location, extent or quality' of a crude oil or natural gas reservoir not previously known to exist (Tordo, 2007). On the other hand, CDE (which can be deducted at up to 30 per cent per year on a declining balance basis) generally includes the costs (to the extent such costs are not CEE) of drilling, converting or completing a well, building a temporary access road or preparing a site. COGPE (which can be deducted at up to 10 per cent per year on a declining balance basis), generally includes the cost of acquiring rights to explore for, drill or extract oil or natural gas, or to acquire an oil or natural gas well or other resource property (Ross, 1988; Taylor, Bramley and Winfield, 2005).

Since 2008/2009, small Canadian-controlled private corporations enjoy a reduced tax rate of 11 per cent on the first Canadian dollar (CAD) 500,000 of their qualifying income. This reduced rate stands to be phased out if the Canadian-controlled private corporation achieves a taxable capital between Canadian dollar (CAD) 10 million and Canadian dollar (CAD) 15 million (CNWP, 2011).

On the provincial front, the fiscal regime in each province plays a critical role in determining the competitiveness of the province's petroleum industry, while at the same time providing a return for that province and for the development of their resources, as well as tax revenue for the province (Plourde, 2010; Campbell, 2013). Similar to the federal fiscal regime, the provinces generally follow a royalty system that aims to strike the right balance between returning a share of the profits to the resource owner, while encouraging the development of the resource to create jobs and economic growth (Campbell, 2013; Dobson, 2015; Mansour and Nakhle, 2016).

Depending on the province in which the oil and gas activity is taking place, provincial income tax rates are within a range of 10 per cent to 16 per cent of the corporation's taxable income. The powers of the provinces to tax derive from Section 92 of the Constitution Act of 1982 (Courchene, 1984; Feehan, 2014; Siu, Nalukwago, Surahmat and Valadão, 2014). The Constitution Act of 1982 requires a corporation that has permanent establishment in more than one province to allocate taxable income to each of the provinces, calculated on the weighted average of revenue, salaries and wages 'reasonably attributable' to the respective provinces (Weiner, 1999; Feehan, 2014).

In provinces where certain mineral rights are owned by private individuals or companies (i.e. "freehold rights" arising from freehold leases), "freehold royalties" are nevertheless paid to the right holder (McGuire and Pak, 2005; Kaplinsky, 2012). However, the province in which jurisdiction the private right holder has his property reserves the right to levy "freehold mineral taxes" on privately held freehold leases. For federal income tax purposes, royalties, unlike provincial income taxes, are fully deductible in computation of federal income tax (McGuire and Pak, 2005; Kaplinsky, 2012).

2.5 Nigeria's Fiscal Regime

The evolution of Nigeria's petroleum fiscal regime originates from two British colonial laws, namely, the Petroleum Ordinance of 1889 and the Mineral Regulation (Oil) Ordinance of 1907 (Omorogbe, 1987). The first concession agreement was granted under the 1907 Ordinance to a German company in 1908, albeit contrary to the dictates of the 1907 Ordinance itself, which required oil exploration to be restricted to only British subjects and British controlled companies (Omorogbe, 1987). However, exploration activities of the German company did not survive World War I. Consequently, no further exploration took place in Nigeria until 1938 when the Shell D'Arcy Petroleum Development Company (the first predecessor of the modern Shell Petroleum Development Company of Nigeria (SPDC)) was awarded a concession grant to explore oil throughout the entire mainland of Nigeria (Omorogbe, 1987). This concession effectively granted the Shell D'Arcy Petroleum Development Company an early monopoly on the exploration of oil in Nigeria.

Following this early monopoly of oil exploration, Nigeria's first commercial oil discovery was made by Shell in 1956 at Oloibiri in Bayelsa State (Kwaghe, 2015; Donwa, Mgbame and Julius, 2015). Consequently, the first oil production in Nigeria was from 1914 to 1937. In 1958, however, Shell D'Arcy – producing 5,100 barrels per day from the country's first oil field, enabled Nigeria to join the ranks of oil producers in that year (Ayodele-Akaakar, 2010). This set the pace for other oil companies such as Mobil and Chevron/Texaco to enter the Nigerian oil exploration environment (Omorogbe, 1987). Notwithstanding the emergence of these and other new entrants, Shell remains, by far, the most dominant oil company in Nigeria – holding the largest acreage in the country from which it produces some 39 per cent of the nation's oil (Frynas, 1998; Manby, 1999).

Although various legislation was enacted after independence to alter the colonial Ordinances, the enactment in 1969 of the Petroleum Act and the accompanying Petroleum (Drilling and Production) Regulations (L.N. 69 of 1969) were what effectively caused the remaining vestiges of the colonial petroleum fiscal regime to disappear and ushered in more modern regulatory and fiscal regimes. Principally, Section 1(1) of the Petroleum Act of 1969 vested ownership and control of petroleum in the federal state. Under Section 2(1) of the Petroleum Act, companies incorporated in Nigeria can be granted one of three rights:

a. a license, to be known as an oil exploration license to explore for petroleum;
b. a license, to be known as an oil prospecting license to prospect for petroleum; and
c. a lease, to be known as an oil mining lease, to search for, win, work, carry away and dispose of petroleum.

Yahaya and Bakare (2018) confirm the importance attached to resource rents and royalties by the Federal Government of Nigeria as fundamental components of the country's petroleum fiscal regime. Furthermore, Ogbonna (2012) asserts that the major features of Nigeria's petroleum fiscal regime encompass fiscal instruments such as resource rents and royalties, petroleum profit tax, licensing fee and other incidentals.

The important centrality of resource rents and royalties is deeply rooted in relevant provisions of the Petroleum (Drilling and Production) Regulations (L.N. 69 of 1969). Regulation 60 provides for resource rents, dividing them into two categories – those paid on an existing oil exploration license, and those payable on an oil prospecting license or oil mining lease. While a minimum rent of NGN 500 is required annually for every year an exploration license is in force, annual rents payable on an oil prospecting license are USD 10 for each square mile. Mining leases attract rents payable at USD 20 for each square kilometer of the first ten years of the lease, then USD 15 for the remainder.

Royalties are provided for under Regulations 61 and 62 of the Petroleum (Drilling and Production) Regulations (L.N. 69 of 1969). Under the regime, royalties in Nigeria are charged at a rate per centum based on the chargeable value of crude oil produced under a license or lease, and vary according to the location or place of production (onshore versus offshore), and the depth of water in the area of production (Oshionebo, 2011). The current royalty regime for non-production sharing contract areas is structured as follows:

- 20 per cent for onshore areas;
- 18.5 per cent in areas up to 100 metres water depth;
- 16.5 per cent in areas up to 200 metres water depth;
- 12.5 per cent in areas from 201 to 500 metres water depth;
- 8 per cent in areas from 501 to 800 metres water depth;
- 4 per cent in areas from 802 to 1 000 metres water depth; and
- 0 per cent in areas beyond 1000 metres water depth.

Royalties charged as part of onshore and shallow offshore production sharing contracts are slightly lower than those listed above:

a. onshore areas -
   - 5 per cent for areas producing below 2000 bpd;
   - 7.5 per cent for production between 2000 to 5000 bpd;
   - 15 per cent for production between 5000 and 10000 bpd; and
   - 20 per cent for production above 10000 bpd.

b. Offshore areas -
   - 2.5 per cent for production below 5000 bpd in water depths up to 100 metres; and
   - 1.5 per cent for production below 5000 bpd in water depths between 100 and 200 metres.

In addition to the resource rent and royalties is the petroleum profit tax, a special dispensation to govern corporate income taxation of oil companies operating (other than refineries) in Nigeria, including local and foreign oil producers (Ayoade, 2010). Equivalent to corporate income tax charged to non-oil sector companies, the petroleum profit tax as a fiscal instrument is based on the Petroleum Profits Tax Act, (1990) (PPTA).

Ayoade (2010) and Madugba, Ekwe and Kalu (2015) summarise the computation of tax under the PPTA in a four-stage process as follows:

a. All income derived from petroleum operations must be ascertained;
b. Expenses permitted to be deducted under Section 10 of the PPTA must be effected to determine adjusted profits;
c. Establishing assessable profits by subtracting loss sustained in previous accounting periods from the present adjusted profit of the present accounting period; and
d. Deducting capital allowances granted on fixed assets from assessable profits to determine chargeable profits on which the appropriate [tax] rate can be levied.

Deductions allowed for petroleum profit tax include rents for lands or buildings, non-productive rents, royalty paid, administrative expenses and capital expenditure such as tangible or intangible expenses from the appraisal of an exploration well (Madugba, Ekwe and Kalu, 2015). Similarly, income generated from the transportation of chargeable oil from ocean going oil tankers operated by or on behalf of the oil producing company from Nigeria to another overseas destination, are excluded. In appropriate circumstances, however, especially in the case of petroleum investment allowance, a cap is set on allowances to the lesser of either the aggregate amount computed or a sum equal to 85 per cent of the assessable profits of the accounting period less 170 per cent of the total amount of the deduction allowed (Petroleum Profit Tax Act, Cap. 354 LFN, 1990).

Petroleum profit tax is currently rated at 85 per cent of chargeable profits, though new oil companies are charged a rate of 67.5 per cent for the first five years of production, and 85 per cent afterwards (Ayoade, 2010).

Another feature of Nigeria's petroleum fiscal regime is the existence of a number of one-time fees such as a signature bonus at the completion of a successful bid, a production bonus (generally limited to instances where a production sharing agreement is in place), various application fees for licenses or other applications, terminal dues (which are meant to facilitate the "evacuation of oil from export terminals"), commission paid to the central bank on taxes under the PPTA, royalties, and rents to the foreign exchange accounts of the Bank and federal tax authorities (Ayoade, 2010).

State participation is also an important feature of Nigeria's petroleum fiscal regime. State participation began in Nigeria as a requirement of the country's membership of OPEC in 1971, leading to the establishment in the same year of the Nigerian National Oil Corporation (NNOC) – the precursor to the current Nigerian National Petroleum Corporation (NNPC). This was established with an initial mandate to undertake exploration and marketing of oil and related activities in the petroleum industry.

Omorogbe (1987) maintains that the Federal Government of Nigeria, through this arrangement, succeeded in enhancing state participation as part of its fiscal regime by three important interventions, namely: (1) negotiating equity participation agreements of 35 per cent with Elf, Shell-BP191, Mobil and Gulf Concessions; (2) assigning to the NNOC in 1972 "all areas in the country not covered by existing licenses and leases, [as well as] concession areas…held by the oil companies which might be surrendered from time to time"; and (3) halting the issuance of new concessions. Cloaked with this arrangement, the state-owned oil company had the mandate to partner with international oil companies for oil exploration purposes. The result is the steady adoption of a variety of contractual vehicles for oil and gas activities in Nigeria, including production sharing agreements, which is the dominant contractual vehicle in Nigeria, followed by contractual joint venture arrangements, and service contracts, which are less commonly used.

Other features that impact the Nigerian petroleum fiscal regime include a limited range of incentives. Firstly, a unique measure that was developed by Nigeria in response to the decline in oil prices and the rise in cost of production in the 1980s was the Memorandum of Understanding (MOU), which provided incentives to joint venture partners in exchange for certain work commitments (Atsegbua, 1993; Ayoade,2010). As a result of the high exploration and production cost at the time, investor appetite for petroleum activity was low, leading to reduced revenues for the federal government (Ayoade, 2010; Eneh, 2011; Onye, 2012). Although the MOU survived for about two decades with occasional revisions in 1991 and 2000, the incentive package was effectively jettisoned by 2007, giving rise to concerns that investor appetite for injecting further capital in Nigeria's oil basins could be negatively impacted – particularly in the context of rising cost of oil production (Emoyan, Akpoborie and Akporhonor, 2008; Ayoade, 2010, Ojide *et al.*, 2012).

The PPTA also avails oil companies of some incentivising deductions, including not limiting the deductions of an oil company to a particular project. Although production sharing agreements provide for ring fence deductions on a project-by-project basis (Ayoade, 2010; Idubor, Asada and Adefi, 2015), oil companies can apply deductions available in the PPTA, broadly as a result of judicial interpretation of the term "petroleum operations". This endorsed the deductions regime in the PPTA for all oil companies and expanded the scope of deductions available to oil companies substantially, to include any "statutory or contractual obligation to incur an expense", whether that expense was 'incidental to petroleum operations' and/or not, provided it was 'wholly, exclusively, and necessarily' incurred (Odusola, 2006; Ayoade, 2010; Gboyega, Søreide, Le and Shukla, 2011).

Other incentives available to oil companies in Nigeria include:

a. Tax holidays offered by the Nigerian Investment Promotion Commission to companies that qualify for "pioneer status" – these tax holidays are limited to the first year that a company commences production. In the case of qualifying foreign companies, they must have incurred capital expenditures of at least NGN 5 million (Akinyomi and Akinyomi, 2011; Fawowe, 2013; Central Bank of Nigeria, 2013); and

b. Oil and gas export free zone – this zone, which encompasses three oil and gas service centers around the ports of Onne (near Port Harcourt), Calabar and Warri, was established by the Oil and Gas Export Free Zone Act No. 8 of 1996 to manage, control and co-ordinate all the activities within the zone. The zone provides facilities to support the export of crude oil. Incentives and fiscal measures approved by government that favour and encourage large investments in the zone include: exemption from "personal income tax", full repatriation of capital and profit, no foreign exchange restrictions, 100 per cent foreign ownership, and no pre-shipment inspection of goods imported into the zone (Ayoade, 2010; Chete, Adeoti, Adeyinka and Ogundele, 2014; Ogbuigwe, 2018).

3. Synthesis of Key Fiscal Regimes of the Countries Examined

Table 1 shows the key characteristics of the oil and gas industry in the countries examined – Canada, Nigeria, Norway and the United Kingdom, along with Ghana. The indicators under which the countries are examined are evolution and development policies of the oil and gas sector, the institutional framework in place, the legal and regulatory framework, and the fiscal instruments in place in securing revenue for the countries studied.

Table 1 Key regimes of the selected countries

Indicator	Ghana	Canada	Nigeria	Norway	United Kingdom
Evolution	1. No clear policy until discovery of oil and gas in 2007. 2. Energy policy document was drafted in 2010.	1. No single energy policy. 2. Policies are decentralised.	1. No clear-cut policy until the country joined OPEC.	1. The "ten oil commandments" drive the industry to date.	1. Currently the Maximising Economic Recovery Strategy is in place.
Institutional Framework	1. The Ministry of Energy is in charge of policy. 2. The Petroleum Commission is in charge of regulation. 3. The GNPC is into commercial production. 4. The GRA collects the revenues.	1. National Energy Board is responsible for the overall regulation. 2. Policies and regulation are left to the provincial governments.	1. The Federal Ministry of Petroleum Resources is in charge of policy. 2. The Department of Petroleum resources is in charge of regulation.	1. Ministry of Petroleum and Energy is in charge of policy. 2. The Norwegian Petroleum Directorate is in charge of regulation. 3. Equinor (formerly Statoil) handles commercial production.	1. The Secretary of State for Energy and Climate Change and the Department of Energy and Climate Change handle policy. 2. The Oil and Gas Authority handles commercial production.

Indicator	Ghana	Canada	Nigeria	Norway	United Kingdom
	5. The Ministry of Finance allocates for spending and monitors the revenue disbursed.		3. Nigerian National Petroleum Corporation performs commercial production.		
Legal and Regulatory Framework	1. The 1992 Constitution vests all natural resources in the President on behalf of citizens. 2. Hybrid of royalty tax. 3.Production sharing agreement. 4. Uses the competitive bidding system.	1. Canada's federal and provincial governments share jurisdiction over Canadian energy policy as well as the legal and regulatory framework. The laws for the oil and gas sector are the Canada Petroleum Resources Act, the Canada Oil and Gas Operations Act, the Canada-Newfoundland Atlantic Accord Implementation Act and the Canada- Nova Scotia Offshore Petroleum Resources Accord Implementation Act. 2. Lease system as a method of acquiring exploration rights.	1. The Constitution vests all oil and gas resources to the government. The Petroleum Act and its regulations govern the oil and gas sector. 2. Joint venture. 3. Production sharing agreement. 4. Service contracts, and 5. Marginal Field Concession.	1. The rights to the petroleum resources on the Norwegian continental shelf are vested in the Norwegian state. The regulatory regime is based on a licensing system, under which companies are granted rights to explore for and produce petroleum. 2.Concessionary	1. The Petroleum Act, 1998 governs oil and gas exploration activities in the United Kingdom. The act vests ownership of petroleum in the Crown and empowers the Secretary of State to grant licenses, through a competitive bidding process, for the search for and extraction of petroleum in the area covered by the license. 2.Concessionary
Fiscal Instrument	1. Royalty 2. Carried interest 3. Additional oil entitlement 4. Capital gains tax 5.Additional participating interest 6. Surface rentals	1. Three tier taxation system. 2. The state does not participate in exploration.	1. Petroleum profit tax 2. Bonuses 3. Royalties.	1. Area fees 2.Environmental tax 3. State's direct financial interest (SDFI). 4. There is no tax stabilisation.	1. Ring fenced corporation tax 2.Supplementary charge. 3. Petroleum tax. 4. The state does not participate in exploration.

Indicator	Ghana	Canada	Nigeria	Norway	United Kingdom
	7. Bonuses. 8. Fiscal regime is subject to negotiation; thus the state gets little. 9.Stabilisation clauses further stifle the ability of the state to increase rates of tax.				

Source: Author's own construct.

The presentation in Table 1 is further discussed and analysed below under the respective indicators identified in Table 1.

3.1 Evolution and Development Policies

From Table 1, whereas Ghana, Canada and Nigeria had no clear-cut policies at the beginning of their oil and gas discoveries, Norway and the United Kingdom had policies in place. In Norway, the standing committee of Parliament on the industry, in 1971 produced what is known as the "ten oil commandments" (Benghida, 2017). The United Kingdom has in place a maximising economic recovery strategy (MER), which was presented to Parliament pursuant to Section 9G of the Petroleum Act, 1998 as amended by the Infrastructure Act, 2015 and came into force on 18 March, 2016.

There is no single energy policy in Canada, rather policies are decentralised. Ghana had no clear policy until 2010 when the energy policy document was prepared. Although oil was discovered in Nigeria in 1965, it was not until 1971, when the country joined the Organisation of Petroleum Exporting Countries that it put a policy document in place.

3.2 Institutional Framework

The countries studied have an institutional framework in place in their oil and gas sectors. Canada has the National Energy Board responsible for the overall regulation of the country's oil and gas industry. Policies and regulations are left to the provincial governments to develop and administer. In Nigeria, the Federal Ministry of Petroleum Resources is in charge of policy, with the Department of Petroleum Resources overseeing regulation, while the Nigerian National

Petroleum Corporation undertakes commercial production. Norway's Ministry of Petroleum and Energy is in charge of policy, the Norwegian Petroleum Directorate is in charge of regulation and Equinor (formerly Statoil) handles commercial production. In the United Kingdom, the Secretary of State for Energy and Climate Change and the Department of Energy and Climate Change handle policy, while the Oil and Gas Authority handles commercial production.

In Ghana, the Ministry of Energy is in charge of policy, the Petroleum Commission is in charge of regulation of the oil and gas sector, while GNPC is into commercial production of oil and gas. The Ghana Revenue Authority collects the revenues accrued from the oil and gas sector while the Ministry of Finance allocates for spending and monitors the revenue disbursed.

The above institutional framework shows a common feature of the countries having an institution that handles commercial production, separate from the institution that handles policy issues, as well as a separate institution that handles regulation. The institutions that handle the commercial production are state institutions, except in the case of Canada.

3.3 Legal and Regulatory Framework

Canada's federal and provincial governments share jurisdiction over Canadian energy policy as well as the legal and regulatory framework. The laws for the oil and gas sector are the Canada Petroleum Resources Act (R.S.C., 1985, c. 36 (2nd Supp.)), the Canada Oil and Gas Operations Act (R.S.C., 1985, c. O-7), the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act, (S.C. 1987, c. 3) and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act (S.C. 1988, c. 28). Canada uses the lease system as a method of acquiring exploration rights to oil and gas deposits.

Nigeria's Constitution vests all oil and gas resources in the government. The Petroleum Act Chapter P10 (Chapter 350 LFN 1990) and its regulations govern the oil and gas sector in Nigeria. The legal and regulatory relationship with investors is varied amongst joint venture, production sharing agreement, service contracts and marginal field concession.

In Norway, the rights to the petroleum resources on the Norwegian continental shelf are vested in the Norwegian state. The regulatory regime is based on a licensing system, under which companies are granted rights to explore for and produce petroleum. Norway, thus, operates a concessionary regime in its legal and regulatory framework in its oil and gas sector. The Petroleum Taxation Act (Act of 13 June 1975 No. 35) governs the oil and gas sector in Norway.

The Petroleum Act, 1998 (1998 c. 17) governs oil and gas exploration activities in the United Kingdom. The act has undergone amendments and with the incorporation of the amendments as at 16 March 2017, the act is now Petroleum Act 1998 (No. 96 of 1998). The act vests ownership of petroleum in the Crown and empowers the Secretary of State to grant licenses, through a competitive bidding process, for the search for and extraction of petroleum in the area covered by the license. The United Kingdom operates the concessionary system in their oil and gas sector.

The United Kingdom and Norway have adopted the concessionary regime for the taxation of their petroleum resources.

In Ghana, the 1992 Constitution vests all natural resources in the President on behalf of the citizens. Ghana applies a hybrid of royalty tax and production sharing agreement in its legal and regulatory relationship with oil companies operating in Ghana. The competitive bidding system is used in allocating oil blocks to prospective investors in the oil and gas industry in Ghana. The Petroleum Income Tax Law, 1987 (P.N.D.C.L. 188) governed the fiscal regime in the oil and gas sector until 2015 when the Income Tax Act, 2015 (Act 896) was enacted, with its attendant regulations to govern the oil and gas sector.

3.4 Fiscal Instruments

Canada has a three-tier taxation system, which is aligned with the three levels of government, namely federal, provincial and territorial, and municipal. The state does not participate in exploration. Nigeria imposes a petroleum profit tax, bonuses and royalties. Norway imposes area fees, environmental tax, state’s direct financial interest (SDFI) as its fiscal instruments in the oil and gas sector. There is no tax stabilisation in Norway. The United Kingdom has a ring-fenced corporation tax, supplementary charge and petroleum tax as its fiscal instruments in the oil and gas sector. As is the case in Canada, the state does not participate in exploration.

The income tax rate in the United Kingdom is now below 30 per cent with a supplementary charge of 20 per cent, which was imposed in April 2002 and calculated upon the same base as the income tax, except that no relief for interest expense is permitted (Boadway and Keen, 2010).

In the United Kingdom, no project pays any tax until payback is achieved. This is a favourable arrangement for investors, because the effective tax rates in the United Kingdom range from 50 per cent for new fields to 75 per cent for older fields (Boadway and Keen, 2010).

A special resource tax applies in the United Kingdom and Norway, however, in the United Kingdom, only fields that received development consent before 1993 qualify. The rate in each country ranges between 40 per cent and 50 per cent, based upon the deemed profitability after allowance for a threshold rate of return representing normal profits (Hogan and Goldsworthy, 2010). The two countries provide tax incentives and extra expenditure reliefs, which result in the taxes typically being paid only when net cash flow begins to turn positive (Hogan and Goldsworthy, 2010).

In Norway, the special petroleum tax (SPT) is not deductible from the income tax but rather acts as an income tax with uplift, leaving Norway with a static 78 per cent take across all classes of investment (Hogan and Goldsworthy, 2010).

The fiscal instruments in Ghana are royalty, carried interest, additional oil entitlement, capital gains tax, additional participating interest, surface rentals and bonuses. The fiscal instruments are subject to negotiation; thus, the state gets little. Stabilisation clauses in petroleum agreements further stifle the ability of the state to increase rates of tax within the stability period.

It is evident, from the discussions above, that in assessing a fiscal regime, the tax rate should not be the only indicator in determining the effectiveness or otherwise of that fiscal regime. Other factors, such as the nature and extent of incentives provided to investors, have to be taken into consideration. This is why Ghana has to take a cue from the experiences of other countries in determining its own fiscal regime for the oil and gas sector, hence its hybrid model. Ghana thus combines the best amongst the contractual and concessionary systems, to give the country, the best of both systems.

4. Conclusion

The lessons Ghana can learn from the comparative country overviews are, first, that Ghana levies 35 per cent as corporate tax rate, whereas the United Kingdom levies 50 per cent for new fields and 75 per cent for older fields. Ghana can thus revise the corporate tax rate for oil and gas companies to 50 per cent as used to be the case in its earlier Petroleum Income Tax Law, 1987 (P.N.D.C.L. 188). The challenge the authors find, however, is that the various petroleum agreements contain the rate of 35 per cent and the companies would surely plead *pacta sunt servanda*, that is, the government should obey faithfully to the terms of the petroleum agreement.

Secondly, Ghana can learn from Norway's position that special petroleum tax is not tax deductible from income tax by also legislating for royalty payments not being deductible from income tax of the petroleum companies. Nigeria has the bad experience of its fiscal regime being driven by its overreliance on oil and gas revenue, a situation which is a caution to Ghana. This is an experience Ghana has to avoid in order not to turn its economy into one driven by oil and gas, otherwise, upon the depletion of these oil and gas reserves, the economy stands to undergo severe macroeconomic shocks, which may lead to the "oil curse" on the economy.

Finally, Canada has a relatively stable fiscal regime and this is a quality that Ghana can learn from, since a stable fiscal regime assures investors of certainty with regard to their investment decisions. Canada, due to its stable fiscal regime, provides certainty in its tax instruments in the oil and gas sector. This is another positive trend which Ghana can adopt by ensuring certainty in the tax instruments in its oil and gas sector.

The analysis of the petroleum fiscal regimes as illustrated in the comparative study in this paper demonstrates clearly that Ghana can review and revise its fiscal regime to enable the country earn more revenue for its growth and development. Ghana can improve on the stability of its fiscal regime with the lessons from Canada and Norway, as well as enhance its revenue inflows through the revision of its corporate income tax rate from lessons from the United Kingdom, and finally avoid the resource curse by learning from the lessons from Nigeria by relying less on the oil and gas revenue for its development.

The need for certainty in the legislation on the fiscal regime for Ghana's oil and gas is observed to be necessary if Ghana is to harness its fair share of the revenue from the petroleum sector. Provisions identified to require a review include Section 66(1)(g) of the Income Tax Act, 2015 (Act 896), the safeguarding of Section 68 of Act 896, an amendment to the Transfer Pricing Regulations, 2012 (L.I. 2188) and a reform of Article 12.1 of the petroleum agreements, as well as a review of Section 71(3) of the Income Tax Act, 2015 (Act 896), to ensure that expatriates are subject to tax, as are all taxpayers not in the petroleum sector.

The fiscal regime, which Ghana adopted for its oil and gas sector, has allowed the country to benefit from the positive impact of revenue inflows from royalties and corporate income tax, as well as the state receiving its share of oil.

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