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Acquah-Andoh, E., Ike, O., Ifelebuegu, A. & Owusu, A.

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Elijah, Acquah-Andoh
[a] School of Energy, Construction and Environment, Coventry University, Priory Street, CV1 5FB. Email: ab4882@coventry.ac.uk

Onyekachi Ike
NPDC – Nigerian Petroleum Development Company, OML 111 Asset. Email: Ike.kachi@gmail.com

Augustine O. Ifelebuegu
School of Energy, Construction and Environment, Coventry University, Priory Street, CV1 5FB. Email: aa5876@coventry.ac.uk

Andrews Owusu
School of Economics, Finance and Accounting, Coventry University, Priory Street, CV1 5FB. Email: ac1980@coventry.ac.uk

Abstract

The UK is believed to hold prolific reserves of shale gas; the quality of which has been compared and sometimes branded superior to the much successful US shale plays. Nonetheless, after more than ten years since the 13th Onshore Licensing Round, the fracking industry is said to have benefited from just £400 million - £500 million of estimated investments and only one partially fracked well with yet an uncertain fate of commercial production. This paradox motivated the current research. Based on a discounted cash flow model, the economic feasibility of the tax regime was evaluated with a special interest in the pad allowance [PA], a major incentive of the fiscal regime. We find that the design of the fiscal regime well achieves the Government's financial objectives, but fails to support shale gas investments at lower gas prices. PA introduces further variability in investor cash flows, ultimately defeating the ethos of the incentive. We propose a reduction in the overall tax rate from 40% to no more than 21%; a removal of the additional tax charge (Supplementary Charge) and an amendment of PA rules to; (1) allow an extension of RFES to PA; (2) permit transfer of activated PA across companies in the same group; and (3) redefine capital expenditure to include intermediate well retirement costs necessary to drill new wells to stimulate production. Such a tax strategy would simplify and align the UK fiscal regime with practices across the US, China, Algeria and Canada. Importantly, it would better match the risk of shale gas investments to its rewards and could better attract investments. We recommend the strategy for emerging unconventional oil and gas producing countries for an efficient design of their fiscal regimes.

Keywords: Fiscal regime, shale gas, pad allowance, risk, investment, taxation

1.0 Introduction

The UK is believed to hold shale gas deposits in the Bowland Hodder of Northern England; the Midland Valley Basin in Scotland and a small area of Wales (BGS-DECC[1] 2014). Indeed, the Oil and Gas Authority's (OGA) reserves models indicate a central estimate of 1,419.6 trillion cubic feet (tcf) of total in-place shale gas resources from all basins (Department for Energy and Climate Change [DECC] 2013; BGS-DECC 2014). Relatedly, the US Energy Information Administration [EIA] (2013; 2015) predicts that about 26 tcf of UK's shale gas reserves are technically recoverable. Importantly, the UK Onshore Oil and Gas Group (UKOOG) recently revised its central production scenarios for shale gas up by 72% to 5.5 billion cubic feet (bcf) per lateral well (UKOOG 2019). This was in recognition of Cuadrilla Resources Ltd, the operating company's higher than anticipated initial flow test results which had shown production of between 3 and 8 million cubic feet (mmcf) a day of shale gas per lateral well from its PNR-1z site (Cuadrilla 2019). Whilst these are promising geological results, the development presents a challenge to the government and industry to consider the most suitable regulatory and fiscal environment that will support the effective and efficient development of the resource.

Extant research on the economics of UK shale gas generally show a very high breakeven natural gas price of over $7 per mmcf (Acquah-Andoh 2015; Ahmed and Rezaei-Gomari 2018). Cooper, Stamford and Azapagic (2018) report that UK shale gas is twice more expensive than liquefied natural gas (LNG) imports and thrice more expensive than the US shale gas. By extension, UK's shale gas may not be profitable within the current regulatory, market, fiscal or geological environments. Nonetheless, the recent drilling results by Cuadrilla and an initial test by Ineos Gas Ltd. from its

[1] BGS - British Geological Survey, DECC – Department for Energy and Climate Change

Tinker Lane site in Nottinghamshire, England, suggest some empirical evidence to believe that geological conditions, although subject to further testing and confirmation, may not be the primary cause for concern about profitability (Cuadrilla 2019; DECC 2013; UKOOG 2019a).

Oil and gas companies are price takers due to the oligopolistic nature of the markets (Berger 1988; Lin 2014). Individual companies thus refrain from investing or cut back on capital expenditure (CE) during low product price regimes (Lin 2014; Liu 2017; Kim and Choi, 2019; Financial Times June 15 2016; Reuters October 3 2018). Generally, fiscal regimes could increase overall operating costs, drive breakeven prices higher and deter investments (Goldsworthy and Zakharova 2010). Nevertheless, regulatory and fiscal factors could be influenced by governments to render otherwise economically unattractive oil and gas development projects attractive by reviewing them. The 13th Onshore Petroleum Licensing Round which awarded first production, exploration and development licences (PEDL) for shale gas in the UK, is now over 10 years. Yet, the industry can only boast of some £400 million to £500 million of investments in the resource, with only one well fractured so far without any certain prospects for commercial production in the near future (Cuadrilla 2019; UKOOG 2019; UKOOG 2019a). Because unconventional oil and gas are riskier to exploit than conventional resources (Aguilera 2014; Le 2018; Hanania et al. 2019), the UK government introduced fiscal incentives to differentiate the tax treatment of shale gas investments from conventional gas investments (HM Treasury 2013a).

In a consultation launched in 2013, the UK government invited evidences on the economics of shale gas development upon which it based the country’s shale gas fiscal regime (HM Treasury 2013a). Generally, respondents agreed with the government over some aspects of its proposed fiscal regime. For example, it was agreed that Pad

Allowance (PA) and Ring Fence Expenditure Supplement (RFES), important incentive features of the proposed fiscal regime, satisfied the government's envisioned objectives for shale gas (HM Treasury 2013a). However, some respondents also raised fundamental issues over the operation of the PA. For example, losses from unsuccessful pads could not be paid from revenues from successful ones; RFES did not cover PA; activated PA could not be transferred across companies in the same group, among others (HM Treasury 2013a). Subsequently, following the consultation, the government introduced cross pad relief (CPR) to allow the settlement of losses from unsuccessful pads with revenues from successful ones, but all other issues were, and remain, unchanged as the government did not believe in additional changes. The said fiscal regime has thus been left unrevised due to what in the authors' opinion stems from an acute lack of scientific research that comprehensively evaluates the economic effects of the critical tax and incentive features that purport to render the fiscal regime generous as claimed by the government. Energy security, job creation, tax revenues for the exchequer among others are the envisioned benefits from shale gas and the government has offered specific fiscal incentives that in its opinion should support the industry to exploit the resource economically (HM Treasury 2013a; OGA 2017; Acquah-Andoh et al. 2018). Yet, since its introduction in 2013, a review of the fiscal regime has been lacking and ultimately led to a lack of feedback on its continued viability in response to current developments such as the level of investments, industry production tests results and geological potential, natural gas markets and pricing, delayed industry projects due to environmental protests, operational difficulty and the general health of shale gas production business with specific lessons from the US.

With motivation from the foregoing paradox, this paper seeks to test the viability of the fiscal regime through an investigation of the efficiency of investments in shale gas exploration and development in the UK. Based on the unique characteristics of the Midland Valley Shale (MVS), we investigate and address the question of the extent to which PA and RFES prove government support for the industry at the early stage of investment in the resource.

The study makes a number of important contributions to our understanding of the impacts of fiscal regimes on unconventional oil and gas investments. For example, as a novel research, it contributes to the development of literature on the economics and fiscal analysis of UK shale gas through a comprehensive analysis of the implications of the proposed shale gas fiscal regime for investor capital and returns. Also, it provides initial feedback on the shale gas fiscal regime and recommends important policy options for its amendment. Finally, the study recommends a fiscal strategy that satisfies capital efficiency tests for investments in an emerging unconventional oil and gas producing country and such strategy should provide a model approach of development to similar emerging countries with potentially commercial volumes of unconventional oil and gas reserves in Europe and elsewhere.

The rest of the paper is organised as follows. Capital efficiency measures and the UK fiscal regime for shale gas, and the MVS are presented in section 2. In section 3, the methods of data analysis, cost and fiscal basis along with production decline considerations and production curves are presented. Section 4 presents and discusses the results, while section 5 concludes the paper with key policy recommendations.

2.1 Capital Investment Efficiency Factors for Shale Gas Development

Total US shale gas production reached 17 tcf in 2016 (EIA 2018), but at the same time substantial amounts have been invested by the industry with a 53% rise in shale oil and gas projects in 2017 over 2016 (Forbes 2017). Developing oil and gas is expensive and risky but shale gas development, in particular, has a higher cost structure although with a larger reserves base than conventional oil or gas (Forbes 2017). Significantly, companies that engage in this venture require a minimum return on risk capital to approve investments. Thus, oil and gas prospects must satisfy a capital efficiency test by showing at least a minimum rate of return.

Recently, the IEA in its *World Energy Investments 2017* noted a transformation in the way oil and gas companies currently operate by focusing on simplified and streamlined projects that have shorter investment payback period (PBP) (IEA 2018). This seems to arise from the high-risk/ high cost, but a low commodity price environment for oil and gas operators . Forbes (2018) reports that the marginal cost of shale gas was \$4/ million British thermal units (mmbtu) for US companies against a unit price of \$3.77/mmbtu (see Figures 1 and 2). Investment in shale gas, under the current market and cost structures thus may even be met by industry with stricter economic evaluation criteria. Some major players in the US Marcellus shale have struggled to keep their heads above water at the current market price for gas. For example, while “Cabot, Range and Antero spent an average of \$1.43 for every \$1.00 they earned in 2016, Chesapeake had negative earnings for 2016 and could not even pay for operating expenses out of its revenues” (Forbes 2018).

For prospective investment and in particular, for mutually exclusive projects, project economists have developed metrics around cost-benefit ratios to measure the relative benefits that projects return vis-à-vis the cost to accept the investment. For example, metrics such as return on investment (ROI), profitability index (PI), net present value (NPV), internal rate of return (IRR), growth rate of return (Komlosi 1999; Capen, Clapp and Phelps 1976; Burkolder, Coopersmith and Schulze 2014; Abughazaleh 2018) are among the simple but most popular measures that have been used in the oil and gas industry to determine capital investment efficiency.

In this research, efficient investment is defined as the ability of shale gas development projects to return investor risk capital plus a premium, within reasonable certainty and timeframe. In other words, a shale gas development project that adds economic value to shareholders' wealth through a fair return on investor capital, which is commensurate with the level of risk borne by the oil and gas company within the operational, market and fiscal environments is considered as an efficient investment. For any oil and gas development investment, the effects of the fiscal regime can be captured as the difference between pre-tax and post-tax cash flows. To gauge the capital investment efficiency, investors may use the IRR as a proxy for the "reservation utility", thus, the return which should trigger investing in the mineral resources (Mommer 1999). For a risky mineral resource project to go ahead, the investor requires a higher risk premium, something that increases the supply price of investment and consequently reduces the economic rent[2] the state can tax (Baunsgaard 2001).

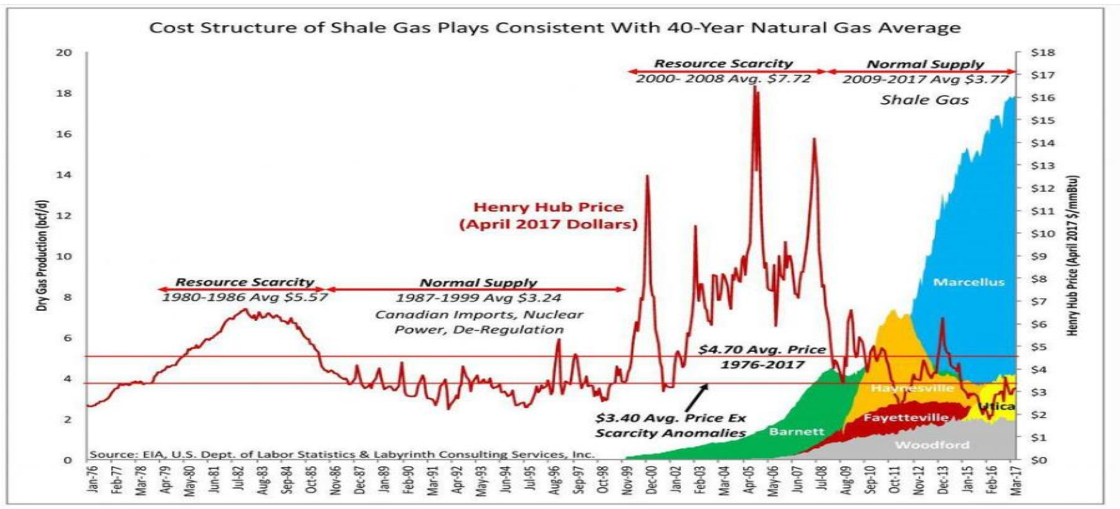

Figure 1. Cost Structure of Shale Gas Plays Consistent With 40-Year Natural Gas Average. Source: EIA, U.S. Dept. of Labor Statistics and Labyrinth Consulting Services, Inc.

Figure 1: 40-Year Cost Structure of Shale Gas Showing (Forbes 2018)
The current cost structure of shale gas production has been found to be consistent with a 40-year average natural gas price at of $3.40 per mmbtu. This price is lower than a typical marginal cost of shale gas production of $4 per mmbtu.

[2] The portion of project returns the state can tax without discouraging investment

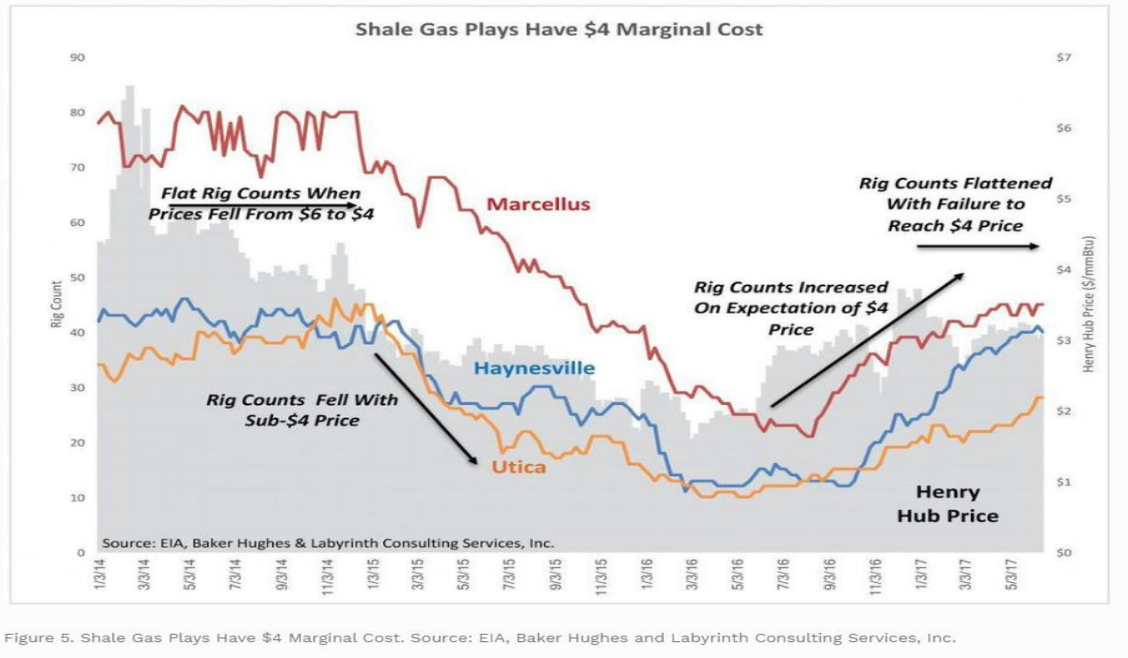

Figure 5. Shale Gas Plays Have $4 Marginal Cost. Source: EIA, Baker Hughes and Labyrinth Consulting Services, Inc.

Figure 2: Marginal Cost of US Shale Gas Plays at $4/MMBTU since 2014 (Forbes 2018)
Shale gas plays have been found to have a typical marginal cost of $4 across the Marcellus, Haynesville and Utica shales.

2.2 Oil and Gas Fiscal Regimes and Investments

Petroleum fiscal regimes (PFR) have been conventionally crafted based on rent theory, to capture economic or resource ‘rent’, defined as the excess profit or excess of hydrocarbon development and production revenues over costs (Tordo, Johnston and Johnston 2010; Johnston 2003; Mommer 1999). The fiscal regime guides and governs transactions that occur between the state that owns the subsurface mineral rights as a principal, and the oil and gas company as an investor and agent that normally takes the risk of exploration with the view to successful commercialisation of oil and or gas to recover their investments and make a profit.

Mommer (1999) describes two types of PFR as Liberal Petroleum Fiscal Regimes (LPFR) and Proprietorial Petroleum Fiscal Regimes (PPFR), and explains that marginal fiscal take is zero in the former but not the latter. Specifically, in LPFRs the state attempts to avoid obstructing the free flow of investments and therefore taxes only excess profits over capital and operating costs. The objective of

LPFR is to achieve low prices; hence fiscal terms attached to a licence may be crafted to encourage competition and cooperation among operators. Significantly, taxes are mostly income based rather than revenue based, which ultimately take into account the geological and market factors before taxing the operator's revenues from resource extraction. PPFR, on the other hand, has a positive marginal rent as a hallmark. This is a reservation ground-rent, which puts a threshold on investment (Mommer 1999). Such fiscal regimes are somewhat efficient too, but the ultimate objective is to collect higher rent, similar to a landlord-tenant relationship. Whereas government policy aims to tax away excess profits from the investor in PPFRs, LPFRs aim to lower prices for consumers via efficient management of natural resources and unhindered development of the resource. According to Mommer (1999), investors require a minimum reservation profit on their investment, but note that above the reservation profit, the host government also requires a reservation ground-rent to be paid by an oil company. Arguably, oil or gas will be invested in and exploited only as long as it is profitable for companies to do so.

The UK's PFR for conventional hydrocarbons has been cited as an excellent example of LPFR in response to the oil industry nationalisations in the 1970s (Mommer 1999). However, to what extent might the UK's excellent management of conventional hydrocarbons extend to unconventional hydrocarbons in a radically different shale industry? Baunsgaard (2001) argues that pure rent represents excess profits unrequired to influence economic behaviour, something that the states can tax away without distorting investor decision to invest in the resource. Baunsgaard (2001), however, cautions that rent is affected by the opportunity cost of investment or the supply price of investment; equated to the investor's minimum required return, which is made up of their CAPEX and operating expenditures (OPEX) plus a risk premium. Cost and cost of capital, the author argues, are affected by commercial and political risks. Consequently, the nature of a country's fiscal design can affect the risk premium that investors expect from oil and gas investments in that country, based on the perceived and the actual inherent political, economic and geological risks.

As argued by Acquah-Andoh *et al.* (2019b), Brexit and geological uncertainty appear to have increased the risk premium for energy investments in the UK. For a given return on investment, the lower the supply price of investment or cost of capital, the higher the economic rent. For this reason, it is argued that during petroleum contract negotiation, host governments may forfeit some revenues to offer incentives to companies in the interest of attracting risk capital to develop and produce their oil and gas resources (Baunsgaard 2001). For emerging unconventional natural gas producer states, this may be a crucial imperative to developing their resource due to the characteristically high risks and uncertainty to investor capital and returns.

Given the specific risky atmosphere for fracking investments in the UK, it might be pragmatic for the government to sacrifice more than normal economic gains at this early stage by redesigning the fiscal regime to a more pro-liberal one in order to incentivise investment as necessary. This will exert a downward force on the supply price of investment to potential investors in shale gas and ultimately, holding the effects of company specific financial risks constant, lead to reduced discount rates (i.e. risk premiums) in investment appraisal models. The pro-liberal PFR is more likely to attract investment because shale gas projects are more expensive and have a longer PBP than conventional offshore field (HM Treasury 2013; Le 2018 p.8; Hanania et al. 2019; Aguilera 2014). The UK government confirms its awareness and notes that "shale gas developments require multiple investments, often across a much wider area than a traditional oil field – increasing ongoing cost and uncertainty" (HM Treasury 2013a). Hence, a potential redesign of the current fiscal regime could be consistent with the government's beliefs and commitment to support the nascent industry.

2.3 The UK Fiscal Regime for Shale Gas

As Table 1 illustrates, the UK Hydrocarbon tax regime shows three major elements: Ring Fence Corporation Tax (RFCT); Supplementary Charge (SC); and Petroleum Revenue Tax (PRT) (Ernst and Young [EY] 2018). RFCT works in similar ways to corporate tax, but restricts the way taxable profits are applied to recover finance costs and losses from oil and gas operations in the UK. SC on the other hand, does not allow for the deduction of finance costs, but applies additional charges on the operator's ring fenced profits. PRT only applies to fields that were granted development consent before 16th March, 1993 (HM Treasury 2013; Acquah-Andoh, 2015). For this research, PRT is not applicable.

Table 1: Summary of Petroleum Taxes

Tax Regime	%	Description
RFCT	30	This is taxed on profits from oil and gas exploration and production.
SC	10	This was 32% in 2011, but reduced to 20% as of 1 January 2015 and then to 10%, from 1 January 2016
PRT	50	Petroleum Revenue Tax Rate is only applicable for fields which received development consent before 16th of March 1993.

Sources: EY (2018); HM Treasury (2013); Acquah-Andoh, (2015)

Specifically, the UK government has stated that "it would be irresponsible of government not to do everything it can to support the safe and sustainable development of shale gas" (HM Treasury 2013a). To this end, the government has created additional incentives regime that should in its own words help to "unlock the investment needed by putting the right fiscal and regulatory framework in place" (HM Treasury 2013). To encourage early investment in shale gas exploration, the government in its Budget 2013, announced additional tax incentives as outlined in Table 2.

Table 2: Tax Incentives for Shale Gas Development in the UK

	Incentive	Description
1	PA	Similar to Field Allowance for conventional fields, PA exempts a portion of shale gas revenues from SC, reducing an operator's effective tax liability on the exempted portion of revenues to potentially 32% or the prevailing rate for RFCT. PA exempts only a share of pad related expenditure – typically those expenditures that qualify for 100% first year capital allowance.
2	Extended RFES from 6 to 10 years	Enables companies to compound uplift their losses of pre-production costs by 10% per annum for up to 10 years, until losses/ costs are fully repaid from future production revenues. This is analogous to the existing regime for conventional hydrocarbon development
3	First Year 100% Capital Allowance	The first year investments by an operator are all allowed to be treated as losses carried forward and recovered from future production revenues before income tax is due. Tax measures recognise there are huge upfront costs to shale gas development and aim to support the industry during this difficult phase, through the recovery of all first year CAPEX plus RFES at 10% capital uplift for 10 years and PA to reduce the initial higher costs per pad. PA could be transferred to unsuccessful pad but could only be activated on the revenues from same pad

Source: HM Treasury 2013; 2013a; EY 2018 and 2019

The government is of the view that, collectively, the tax proposal in Tables 1 and 2 make a "generous" fiscal regime for shale gas in the UK (HM Treasury 2013). In particular, the regime combines the fiscal features of the traditional Ring Fence Tax Regime and the additional incentives to potentially spice investment (HM Treasury 2013). Figure 3 summarises the fiscal regime and illustrates a schematic flow of the split of shale gas revenues between investors and the state. From left to right, operator gross revenues are taxed twice at a RFCT gate (E2), and SC gate (E4) before reaching operator net revenues after tax. RFCT is charged after allowing for ring fence costs (E3), whilst SC is made after allowing for finance costs and a moderating effect of PA and RFES for all first-year CAPEX as well as exploration costs.

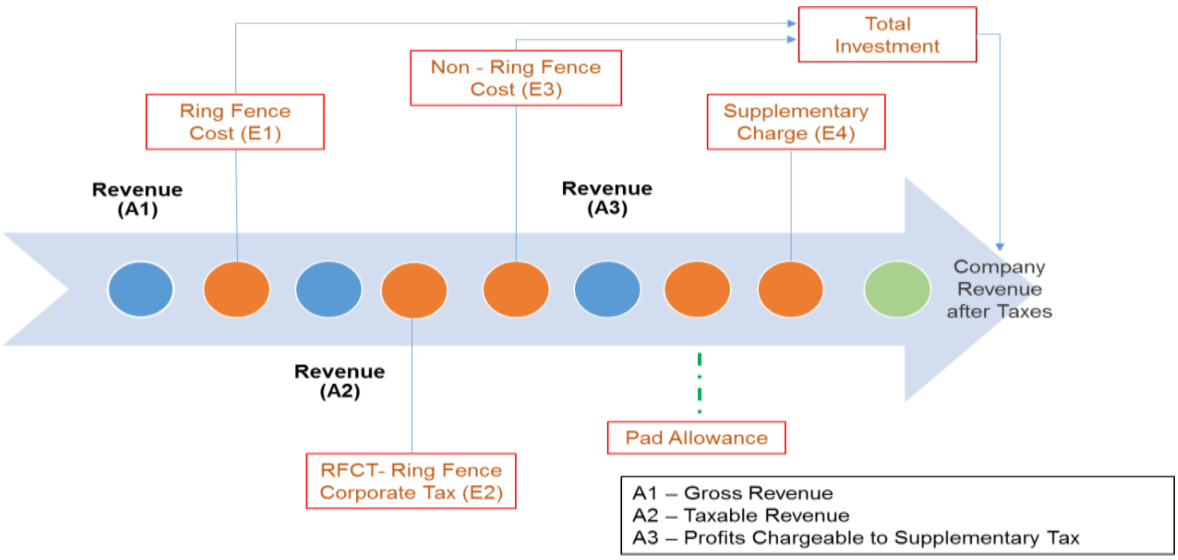

Figure 3: Illustration of the UK's Shale Gas Tax Framework

2.4 The Midland Valley Shale of UK

The midland valley (MV) is made up of four carboniferous stratigraphic units that contain shale oil and gas at different depths stacked vertically. Its mature organic-rich mudstones are stacked in a sandstone-limestone-shale interval of up to 9,800 feet (ft) (3,000 metres (m)) thick. The thickness of the various shale units varies from a few inches up to 160ft and the percentage of shale in the succession varies from 0 to 85%. Due to burial, uplift and erosion, shales in the MV are matured for oil generation from depths of about 2,300ft. The total gas in place is about 49.4 -134.6 tcf (BGS-DECC 2014). Whereas Table 3 summarises the geophysical and petrophysical properties of the MV shale used to develop this research, Figure 4 represents the map of the carboniferous units and areas with potentials for shale resource exploration.

Table 3: Summarised Petro-Physical & Geophysical Properties of the MV Shale

Reserve Estimates	Total Gas In Place (GIP) Estimates in TCF				Petrophysical Properties	Parameter	Value	Description
	Shale Gas	Low (P90)	Central (P50)	High (P10)		Porosity	Less than 10%	The shales have a porosity which ranges from between 4-7%. However, there is limited data on this aspect.
	Limestone Coal Formation	1.4	3.2	6.1		Shale Thickness	50-160 feet	The shale units are generally thin but occur in a stacked sequence
	Lower Limestone Formation	3.7	6.3	10.8		Area (Km^2)	30,000	Figure has been provided from course work notes.
	West Lothian Oil-Shale Unit	16.2	32.6	66.7		Permeability	1E-5 to 1E-4 millidarcy (md)	Figure assumed from U.S Shale Gas Data (Andrews 2013)
	Gullane Unit	12.5	32	73.2		Reservoir Pressure	3,800 Psi	Figure assumed from U.S Shale Gas Data (Andrews 2013)
	Combined	49.4	80.3	134.6		Average RF	From 10% - 19%	Figure assumed from U.S Shale Gas Data (British Geological Survey [BGS] 2013)

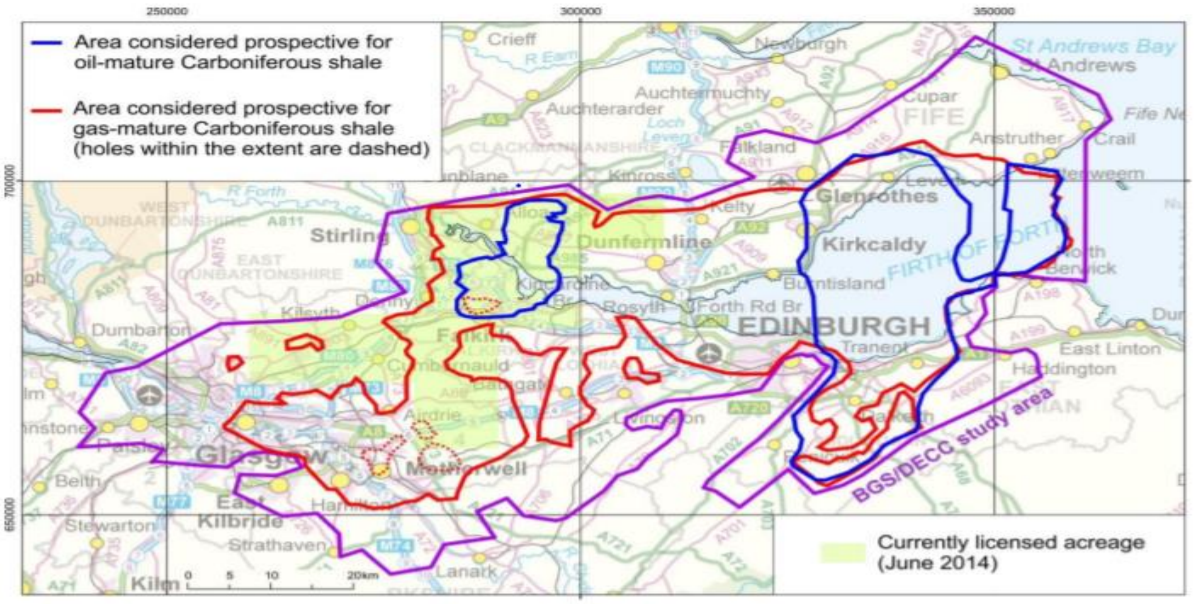

Figure 4: Prospective Area for Shale Gas and oil of the Midland Valley Shale.
Red Area (gas), blue area (oil) and purple area (study area). (Source: BGS-DECC 2014)

3. Methodology

This section presents the assumptions and models that underpin the research. Specifically, we detail the geological basis for production decline for three development concepts in subsection 3.1, and present the resulting production curves (subsections 3.2 – 3.3). We also present economic and fiscal assumptions as well as the models that were used to generate the results of the study (subsections 3.4-3.6). Of the three development concepts, cases one and two arguably produce the production curves that best align with current research and industry data about the UK's shale gas production (UKOOG 2019, Cuadrilla 2019, Acquah-Andoh 2015; Institute of Directors [IoD] 2013). Nonetheless, for the sake of the analysis, case three was also considered for its economic and fiscal implications.

3.1 Development Concepts and Data

A multi-pad drilling was assumed for the development of the MV shale due to its cost efficiency and popularity within the fracking industry. Preliminary development considerations are summarised as development concepts in Table 4.

Table 4: Field Development Concepts and Production Curve Scenarios

Parameter	Concept/ Case 1	Concept/ Case 2	Concept/ Case 3
Drilling	10 well pads with 10 laterals	10 well pads with 40 laterals	10 x 10 well-pads with 40 laterals per pad
Drilling Schedule	1 well pad per year	1 well pad per year	10 well pads per year
Exploratory Wells	4	4	4
Well Flow Rate	2mmscf per day	3mmcf per day	4mmcf per day
Gas Recovery/ Well	4.9 billion cubic feet	7.4 billion cubic feet	9.87 billion cubic feet
Estimated Ultimate Recovery	1.8 trillion cubic feet	2.8 trillion cubic feet	3.8 trillion cubic feet

As Table 4 demonstrates, the technical considerations for well pad density adopted are aimed at achieving an average of 10-15% recovery rate. The average well spacing ranged 40-150acres/well. The average surface well pad requirement was 5 acres

(2ha) IoD 2013). The drilling and fracturing of development wells follow a phased yearly approach, with 1-40 average number of pad drilled per year. Similar economic simulations have been considered in the work of Acquah-Andoh (2015). Overall, Table 4 results in various production curves as shown in Figures 5 and 6.

3.2 Production Curves

Production profiles were modelled based on three initial flow rate (Qi) scenarios and varying total number of wells drilled throughout the proposed field life. Guoa et al. (2017) and Wachtmeister et al. (2017) in a study of US shale gas wells production data found that a hyperbolic decline based on the Arps's decline equation best explained the decline behaviours of US shale gas wells. Hyperbolic decline based on Arps's equation was thus used to construct the production model for the UK shale gas, in line with the reasoning in authoritative research on UK shale gas resource potential (BGS-DECC 2014; IoD 2013; Regeneris and Cuadrilla 2011). B-factor of 0.6377 and average monthly (Di) factor of 0.0325, assumed from the Fayetteville Field of the US to generate a 45-year well production profile. For this model the abandonment production rate (economic limit) was assumed to be 0.09mmscfd. It is important to note that the average well production decline generated with a hyperbolic formula decreases a well's production life. The consequent decline trend was analogous to those from Regeneris and Caudrila's work on the Bowland shale of the UK in 2011 (Regeneris and Cuadrilla 2011).

Figures 5 and 6 show the resulting production curves for the single well and multi-well full field development concepts for cases one, two and three. The yearly drilling requirements imply a need for substantial yearly CAPEX and will also imply a percentage increase in OPEX. This is typical of shale gas development projects because costs tend to be much higher in the early years of exploration and development.

3.3 Initial Production

The production profiles displayed in Figures 5 and 6 present three scenarios of estimated ultimate recovery (EUR) of reserves based on assumed initial production of 2 million cubic feet per day (mmcfd) to 4mmcfd. The EUR is affected by the value of the decline and hyperbolic constant used in modelling. Average well production per year for the 45-year period ranged from 4.9 to 9.8 bcf. This rate is similar to that reported in earlier work by Regenris and Cuadrilla (2011), IoD (2013), Hughes (2014), Acquah-Andoh (2015) and more recently by UKOOG (2019).

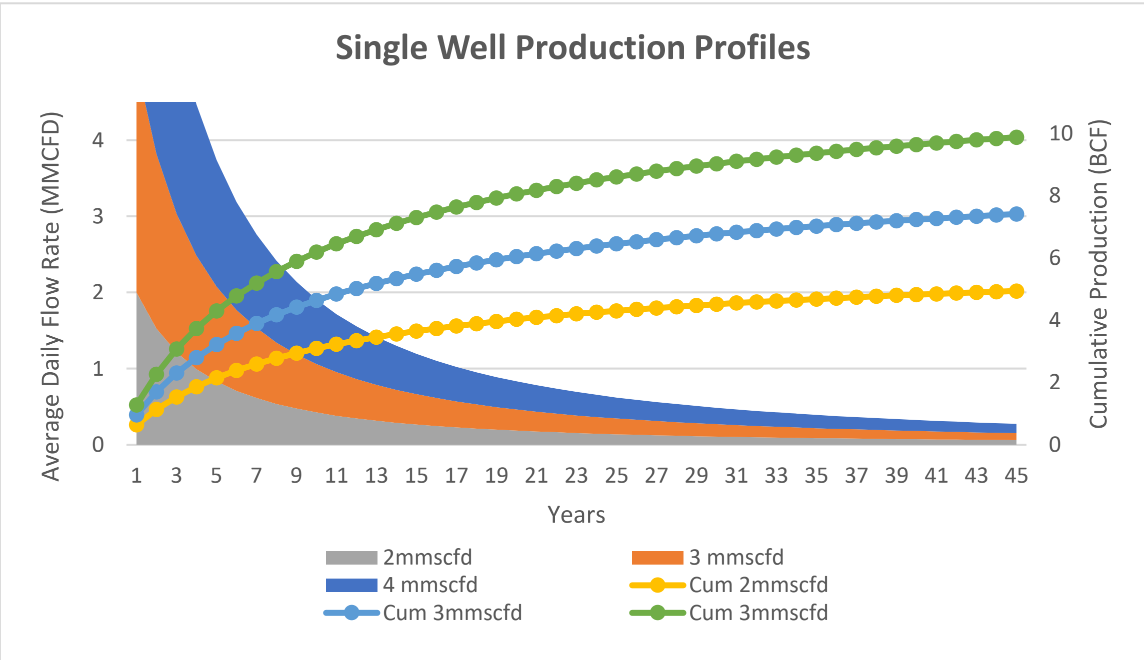

Figure 5: Production Curves/ Profiles for a Single Lateral Well

Figure 5 shows the full range of production curves based on initial well flow rates of 2 mmcfd, 3 mmcfd and 4 mmcfd. The graph also illustrates the estimated ultimate recovery EUR for all 3 production concepts at 4.9 bcf, 7.4 bcf and 9.8 bcf for a single lateral well. These production profiles translate to the total pad production profiles presented in Figure 6 below for all lateral well production scenarios.

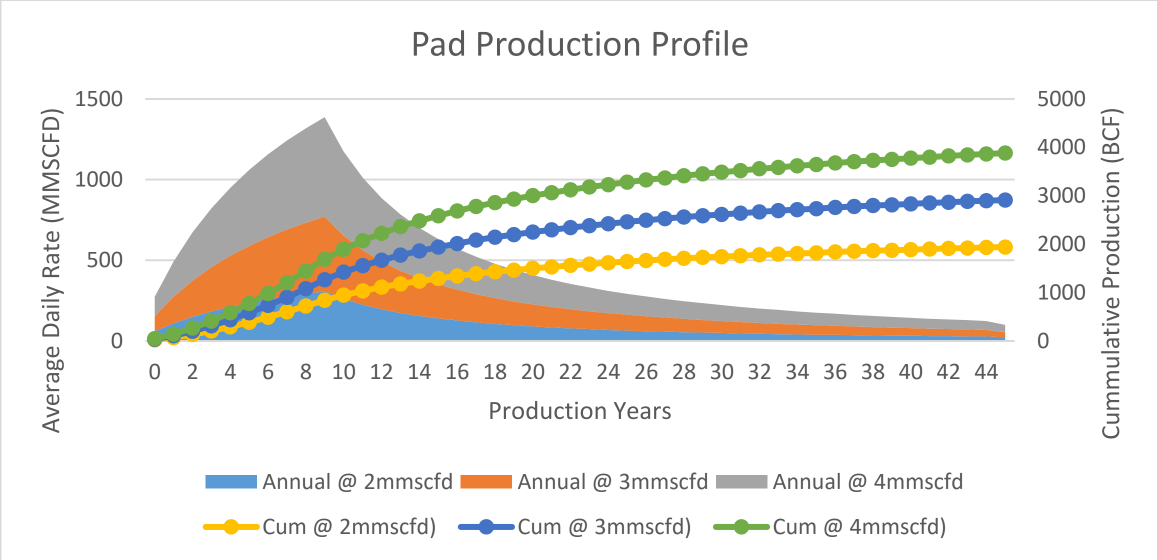

Figure 6: Pad Production Profiles Showing Annual Cumulative Pad Rates

3.4 Field Abandonment

In this research, we assumed that wells will be abandoned at an economic rate of 0.09 mmcfd or after 45years of production, whichever occurs first. This is because production rates for a well are expected to be so low leading to a negative cash flow on a well by well basis, a situation typical of shale gas wells (Hughes 2014). We also assumed that 10 well pads with 40 laterals will use 2 hectares of land (Acquah-Andoh 2015; Kaiser 2012).

3.5 Capital and Operating Expenditures

CAPEX comprise drilling, completion, fracturing cost, license, land acquisition and facility costs (Kaiser 2012). Costs from the US Haynesville shale wells were used as a guide in CAPEX assumptions for this study. Abandonment costs are included in the cost of wells. Community benefits are not a legal requirement of the shale gas fiscal regime of the UK; industry players who are members of the UKOOG have signed up to this proposal by UKOOG as a way of earning community trust to operate. As it has been argued, industry players are not obliged to pay these fees hence this has not been captured in our models as the study attempts to capture and measure the implications of the UK fiscal regime as it exists by law. Exploration expenditure was immediately depreciated and all other CAPEX was depreciated at 10% on a RBB.

Because shale gas is still at an early stage in UK and the difficulty in obtaining OPEX data, fixed OPEX and Variable OPEX were assumed based on inputs from the IoD (2013) estimates. Therefore, OPEX is escalated at 3%. Gas price of 32.12 pence per therm was used in our models and converted to its $/mmbtu equivalent of $4.69/mmbtu. Tabel 5 summarises our cost references for this research.

Table 5: Comparative CAPEX and OPEX References

Cost	**Reference Project**	**Cost/ Source**
Drilling & Completion	Haynesville shale, US	$7- $10 million (Kaiser & Yu 2011); $5 million - $15 million (Kaier 2012)
Drilling and Completion	Bowland shale, UK	£8 to £12 million (EY and UKOOG 2014); £10.5 million (Regeneris Consulting & Cuadrilla Resources Ltd. 2011); $15 - $20 million (Acquah-Andoh 2015)
Facility Costs	Bowland shale, UK	15% of drilling and fracturing costs (Regeneris Consulting & Cuadrilla Resources Ltd. 2011); £5 million (Amion Consulting and Peel Gas and Oil Ltd. 2015)
Operating costs	Bowland shale, UK	Fixed opex = £0.5 million per year; variable opex 2.5% of cumulative capex (IoD 2013); $1.50/ Mcf variable; $25,000 fixed plus 15% overheads (Acquah-Andoh 2015);
Operating costs	Haynesville shale, US	2008 = $0.85; 2009 = $0.80; 2010 = $0.50 (Kaiser 2012)

3.6 Economic Modelling

3.6.1. Cash Flow Modelling

Net Cash Flow (NCF) is the summation of all cash received, less all associated expenses, taxes and investment on an annual basis over the life of a project. Equation (1) specifies the cash flow model for our analysis.

$$NCF_t = [GR_t - RF\,Exp_t - RFCT_t - FinCost_t - (SupCharge_t + PA_t) - OtherCosts_t - CAPEX_t * (1 - B) - OPEX_t] \quad \text{...... (1)}$$

Where NCF_t is the net cash flow in year t, GR_t is the gross revenues in year t, $RF\,Exp_t$ is the ring fence expenditure in year t, $RFCT_t$ is the RFCT charge in year t, $FinCost_t$ is finance cost in year t, $SupCharge_t$ is a SC in year t, PA_t is the PA in year t, $OtherCosts_t$ is all other costs incurred by an operator, but which do not qualify as ring fence expenses under the fiscal regime in year t, $CAPEX_t$ is the capital expenditures in year t, B is proxy for the investment credit/ capital allowance, such as the RFES and $OPEX_t$ is for all qualifying operating expenditures in year t. From left to right, equation (1) also illustrates the point at which various variables entered the determination of NCF in our modelling. RFCT was charged at 30%, before SC at 10%.

It is important to highlight that the cash flow model adopted in this study has been applied by other researchers (e.g. Iledare 2004; 2010; Kaiser 2012; Sen 2014). Whereas Iledare (2004; 2010) applied a similar modelling concept to model a progressive development strategy for oil and gas in Nigeria, Kaiser (2012) applied a similar concept to analyse the profitability of Haynesville shale of the US. Recently, Sen (2014) applied the same modelling concept to analyse India's fiscal regime for petroleum exploration.

3.6.2. Gross Revenues

The gross revenues in year t are proceeds from the sale of shale gas. This was modelled using equation (2) below.

$$GR_i = \sum g_t^i P_t^i Q_t^i \quad \text{...... (2)}$$

Generally, g_t^i, P_t^i, and Q_t^i each represents the conversion factor of commodity *i* in year *t*, projected price of commodity *i* and total production of commodity *i*, respectively. In this research, the saleable unit of gas is mmbtu. Gas is not converted, hence equation (2) was adapted as:

$$GR_i = \sum 1\, x\, P_t^i Q_t^i \qquad \text{..... (3)}$$

3.6.3 Investment Decision Criteria

In this study, and in line with existing oil and gas economics literature and practice, three investment appraisal methods were used to appraise the viability of the project which include PBP, NPV and IRR. PBP is the time it takes for project investments to be fully recovered. Subsequent revenues received after the PBP are considered profits generated by the project. As reported earlier, oil and gas companies now prefer projects with shorter PBP (Forbes 2018). Equation 4 represents our PBP model as follows:

$$PBP = Cumulative - ve\ NCF\ years + \frac{1}{(+ve\ NCF - (-ve\ NCF)) * (-ve\ NCF)} \qquad \text{.... (4)}$$

where *Cumulative -ve NCF* years represents the cumulative negative net cash flows years; +ve NCF represents positive net cash flows and -ve NCF represents negative net cash flows.

NPV is the summation of all future project cash flows discounted back into the present value to recognise the time value of money (Clews 2016). It represents the worth of future cash that would be invested today at a specified interest rate to yield that cash at that time in the future. Considering our analysis is based on a 45 year well life, it was necessary to convert future costs and revenues into present worth for valid and reliable economic reasoning. Equation 5 represents our NPV model as follows:

$$NPV = \sum_{t=1}^{k} \frac{NCF_t}{(1+r)^t} \qquad \text{…..... (5)}$$

where NCF_t is the net cash flow, t is the reference period (years) and r is the discount rate.

The IRR is the discount rate at which the NPV of the project cash flow reduces to zero. It is an important parameter in measuring the profitability of projects. Equation 6 represents our IRR model as follows:

$$IRR = \sum_{i=1}^{n} \frac{NCF_t}{(1+r)^t} = 0 \qquad \text{…. (6)}$$

Where IRR represents the internal rate of return, NCF_t represents the net cash flows in time t, r represents the discount rate and t represents the time in years.

Significantly, the development and profitability of shale gas plays depend on a range of factors that influences the field economics, which includes the gas price, production volumes, CAPEX and OPEX (Kaiser 2012). Table 6 summarises the input parameters used in this research. Consistent with previous literature, a discount rate of 10% was applied to our cash flows. For example, the Society of Petroleum Evaluation Engineers' [SPEE] (2007; 2009; 2013; 2018; 2019) survey of the oil and gas industry's asset valuation practices has reported the application of an average of 10% discount rate as common practice. This is indeed confirmed by the application of 10% in most oil and gas economics research (see Daniel 2017; Tinker 2013; Kaiser 2012; Chen et al 2015; Acquah-Andoh 2015, 2019).

Table 6: Summary of Input Parameters

Parameter	Assumed Rate
Well drilling, completion & abandonment costs	$15 million – $25 million
Facility costs	$10 million – 20 million
Variable opex, including overheads	2% of capex
Fixed opex	$25,000 per annum
Gas price	$4.69/ mmbtu
Land Acquisition cost	$0.43 million/ acre
Well spacing	40 acres
Cost of capital	10%
Ring fence corporate charge	30%
Supplementary charge	10%
Pad Allowance activated	100%
Initial production	2 mmcfd – 4 mmcfd
Gas price escalation	3%
Opex escalation	3%
Capex escalation	3%

In this study, the effects of the parameters in Table 6 on project profitability were examined and we now present and discuss the results in section 4.

4.0 Results and Discussion

4.1 Economics of the Midland Valley Shale

Table 7 presents the results of economic analysis of the production curves.

Table 7: Results of Economics Analysis[a]

Case/ Model Input Parameters	Results	Pre-tax	Post-tax
Case One: EUR = 2mmcfd; Capex = $100M/ well; Opex = $1.2/ Mcf; IP = 2mmcfd; FRCT = 30%; SC = 10%; PA = 100%; Gas price = $4.9/ mmbtu	NPV ($Million)	-2,732	-2,732
	IRR (%)	-9.6	-9.6
	Average yearly EUR per well (Bcf)	4.9	4.9
Case Two: EUR = 3mmcfd; Capex = $110M/ well; Opex = $1.5/ Mcf; IP = 3mmcfd; RFCT = 30%; SC = 10%; PA = 100%; Gas price = $4.9/ mmbtu	NPV ($Million)	-1,189	-1,189
	IRR (%)	4	4
	Average yearly EUR per well (Bcf)	7.4	7.4
Case Three: EUR = 4mmcfd; Capex = $120M/ well; Opex = $1.5/ Mcf; IP = 4mmcfd; RFCT = 30%; SC = 10%; PA = 100%; Gas price $4.9/ mmbtu	NPV ($Million)	2,517	2,098
	IRR (%)	22	18
	PBP	13	19
	Average yearly EUR per well (Bcf)	9.8	9.8

[a] Table 7 presents the economic feasibility of all production scenarios as earlier presented in Table 4. At gas price of up to $4.69 per mmbtu, average EUR of up to 7.4 bcf per well over the life of shale gas project is unprofitable. At 7.4 bcf EUR, a minimum gas price of $6.20 per mmbtu is required to breakeven. An EUR of 9.8 bcf per well returns a post-tax NPV of ~ $2.1 billion but this recovery rate is about 22.5% higher than the current maximum estimates for the US's prolific Marcellus shale and also 22.5% higher than the UKOOG's current average estimate of 8 bcf per well for UK shale gas wells and is thus highly unlikely to be warranted during the short to medium term of shale gas investment.

As shown in Table 7, at a flow rate of 3 mmcfd per well (case two), equivalent to an average yearly production of 7.4 bcf per well, the results are unfavourable with a pre- tax NPV of negative $1,189 million, an IRR of 4% and a break-even price of $6.2 per mmbtu at 10% cost of capital; this is $4.2/ Mcf for Canada (Chen et. al 2015). At ~ 5 bcf per well EUR (i.e. case one), the results are less favourable with pre-tax NPV of negative $2,732 million and IRR of negative 9.6% at 10% discount rate and require a breakeven price of $10.29 per mmbtu.

Figures 7 and 8 illustrate the pre-tax and post-tax cash flows for case three – the only positive economics of the three scenarios, with EUR of ~ 10 bcf per well. The results indicate acceptable but not very strong economics. At gas price of $4.69/ mmbtu (~47p per therm), a pre-tax NPV of positive $2,517 Million is obtained along with an IRR of 22%. Post tax NPV and IRR drop to $2,098 million and 18% respectively. Relatedly, PBP increases from 13 years to 19 years for pre-tax and post-tax economics, respectively. This sharply contrasts the average PBP of 6 years for conventional oil and gas projects in UK (Oil and Gas UK 2019).

To put the results into perspective, the US shale wells which have been cited widely as a benchmark for the UK shale potential have been noted to have produced an average of about 1 bcf per year only, during the initial years of shale gas production (UKOOG 2019; EIA 2011). It is thus uncertain that UK shale gas wells would be as much as four times more productive at 4 bcf initially. Although UKOOG estimates a central case production of 5.5 bcf per well on average for UK shale gas, it is argued in this research that such is highly unlikely to be warranted given the limited extent of fracking on Cuadrilla's initial flow test on its PNR-1z well and the fact that the UK is an emerging producer with enormous uncertainty around recovery rates, price and costs. We believe that the EUR used in the foregoing analysis underscores a cautious approach to modelling the economics of UK shale gas at this early stage of industry in this research.

It must be said that given the nature of the riskiness of unconventional gas exploitation and in particular the UK as an emerging producer, 10% cost of capital is unlikely to be acceptable for fracking operations. Yet, ironically, at a typical gas price of $4.69 per mmbtu and an EUR of 7.4bcf, ~35% more than the UKOOG's new estimate of 5.5 bcf and 45% more than the current average well production of 5.1 bcf in the Marcellus Basin of the US (UKOOG 2019), fracking operations fail to add economic value based on the analysis contained in this research. Ultimately, the unstable economic results warrant a government intervention to inject further confidence in the industry in order to spur the much needed early, but risky investments in shale gas development.

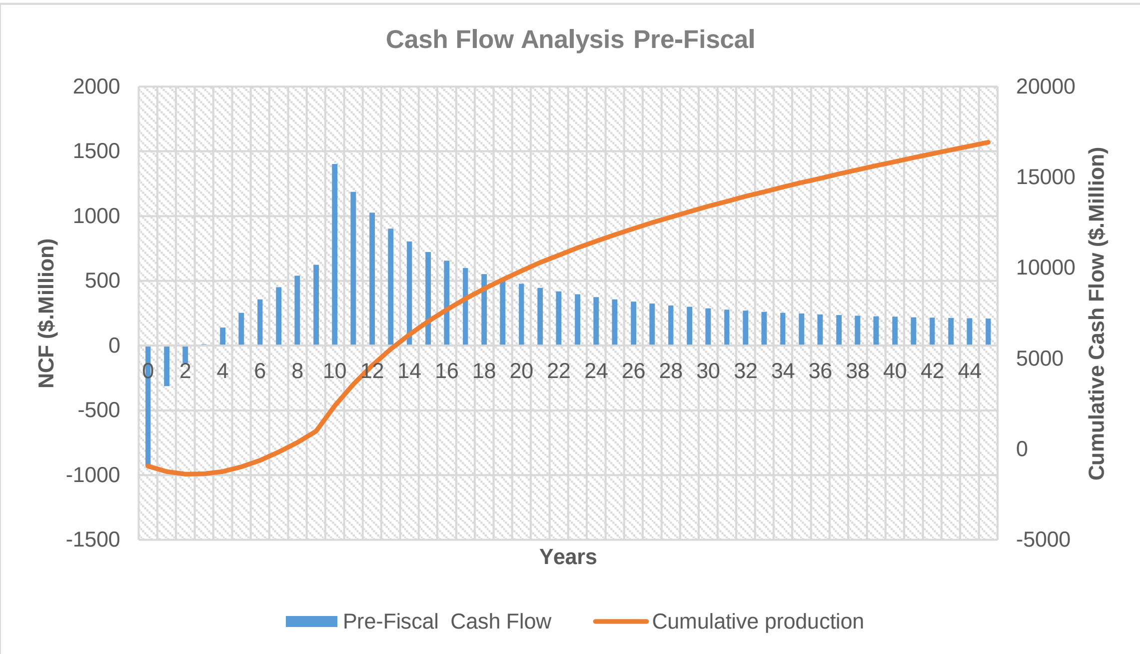

Figure 7: Pre-Tax Cash Flow at $4.69/mmbtu Gas Price for Case Three

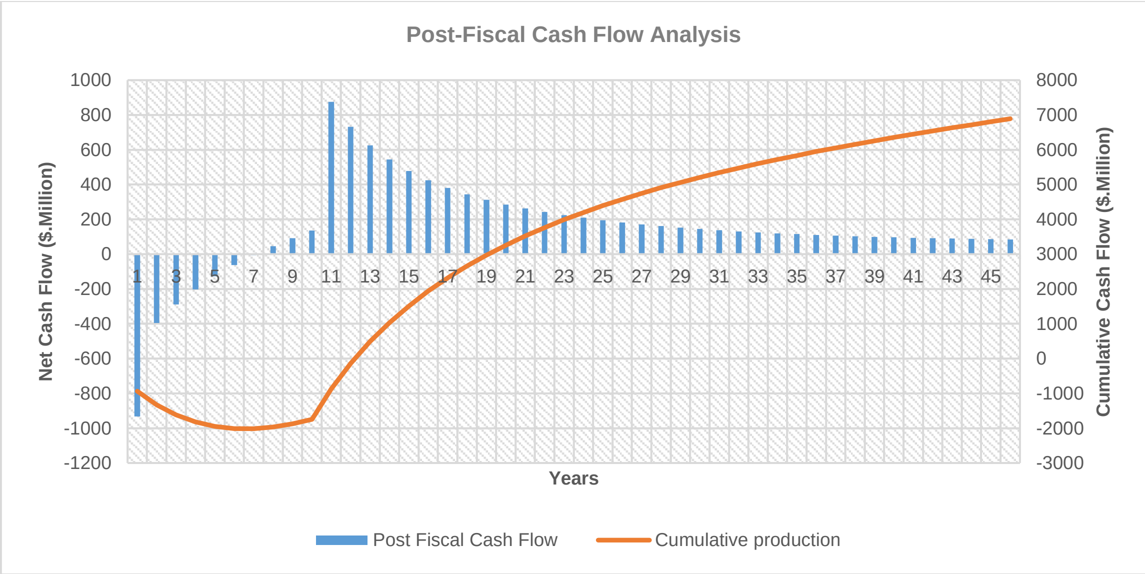

Figure 8: Post-Fiscal Cash Flow at $4.69/mmbtu

Designing pro-liberal fiscal regimes for the development of natural resources by emerging oil and gas producers is no new practice (Baunsgaard 2001). Such liberal regimes appear to evidence government commitment to: (1) attracting risk capital; and (2) understanding the potential of the resource. Subsequently, the fiscal regime may be redesigned to extract more economic rent following the elapse of the time for learning about the potential for the resource in their territory. Emerging unconventional producing states must be willing to embrace these truths in order to make their attempts at developing their resources successful. We argue that 19 years is too long a time for the recovery of investor capital in shale gas development. It would thus be a beneficial decision for the UK government to introduce further confidence in investors in shale by way of additional incentives that better guarantee the recovery of investor capital over a more reasonable period and at more acceptable and stable returns.

4.2 Effects of the PA on Investor Returns

PA is a shale gas tax incentive which was announced by the Conservative Government in Budget 2013 with the following objectives: (1) encourage early investment in shale gas exploration and development in UK; (2) maximise economic production from UK shale reserves; and (3) ensure a fair return to UK tax payer (HM Treasury 2013). Further, the Government intends to use the PA as a vehicle for ensuring flexibility of, and avoiding complexity within the shale gas fiscal regime. By these objectives, it hopes to adapt the fiscal regime as the industry develops and moves from exploration through development and production.

It is important to highlight that PA operates to exempt a portion of operator profits from additional taxes called SC, and reduce the effective tax on the said portion of profits from 62% to 32% (currently 40% to 30%). The amount of profit exempt from SC is set to a proportion of the capital expenditure incurred on the pad. In addition, there is a cross pad relief; a PA operational feature which permits losses from unsuccessful pads to be covered from allowances generated from successful pads, subject to two conditions. Firstly, PA can only be activated from revenues from successful shale gas sites. Secondly, for cross pad relief purposes, allowance can only be activated 3 years after the expenses were incurred. The government's reason for the latter condition is to discourage premature abandonment of projects. The spirit of the regime's incentives is consistent with good petroleum fiscal regime design practice because the tax regime targets profits rather than revenues (Johnston 2003; Nakhle 2016; Nauffal, Kassab, and Nakhle 2016; Nakhle 2010). From Figure 9, analogous to R-Factor contracts, the PA appears to introduce a dampening effect into the fiscal regime; wiping out the upside potential of shale gas investor returns on one hand - the windfall profits that may result from favourable geological, cost and price conditions, but protecting the investor's risk capital to an extent, on the downside too as suggested by Johnston (2003).

It can be seen from Figure 9 though, that as gas price increases from $3.10/ mmbtu towards $10/ mmbtu, the vertical distance between the pre-fiscal IRR on one hand and PA and post- fiscal IRR line widens. This gap indicates the effects of PA at higher gas prices on investor returns; taxing away economic rent in a manner similar to PPFRs as suggested by Mommer (1999). Interestingly, this gap disappears as natural gas price falls to the lower end of the 3 curves and in fact all curves converge at $3.10/ mmbtu. This situation implies that the PA machinery provides less and less protection/ support for investors at lower natural gas prices where they need it most, but quickly gathers the windfall that may result from increased prices for the government. This "hidden tax" machinery well satisfies government objective of ensuring returns for taxpayers, but the situation conflicts with popular fiscal design ideals of fair government-investor risk-reward sharing in petroleum fiscal design literature (Nakhle 2008).

Currently, PA rules do not permit the extension of RFES to allowances; RFES allows an operator to uplift their losses by 10% for up to 10 years, to reasonably protect the time value of the loss, until it can be recovered. In addition, activated PA cannot be transferred across companies in the same group. The joint implications of these rules are that: (1) the effectiveness of cross pad relief still depends on the availability of sufficient income from an operator's pool of pads, but without recourse to group production income. It is thus still likely that an operator may not receive all of its investments in unsuccessful pads even though it may have generated production income and hence PA within its group of companies, and this rule could be too restrictive; and (2) delayed activation of PA suggests potential accumulation of interest cost for, many years, at least 3 years. For smaller companies, this could prove burdensome, and although the benefits of RFES could mitigate such impact and likely create further investment incentive, RFES does not extend to PA. For early investors in UK shale gas, the risk of unsuccessful pads is plausible due to uncertainty surrounding the geological potential at the early stage.

In addition, for the purposes of PA, the definition of CAPEX is limited to expenditure that attracts 100% first year capital allowances. By extension, the definition excludes incidental expenditures required to incur such qualifying CAPEX. Further, unconventional oil and gas wells cost more to drill and deplete faster (Kaiser 2012). Continuous drilling of new wells is thus required to maintain production (Kaiser 2012). Consequently, incurring plug and abandonment costs on existing lateral wells mid-life is a requirement in order to drill new ones. Currently, such intermediate periodic expenditure is not covered by the allowance and it is argued that this could potentially discourage investment at the initial exploration phase of industry when geological potential has yet to be firmly established. Although the government consultation recognised that it would have to redefine this later, we argue that by resolving this issue at the present time, further certainty could be introduced into the fiscal regime; by assuring certainty of tax treatment, and boost early investment.

In a response document to the UK government-public consultation on the shale gas fiscal regime, a majority of respondents suggested that the PA increased the attractiveness of economic but uncommercial projects (HM Treasury 2013) and therefore acts as incentive for shale gas investment. Based on the findings of this research and as Figure 9 shows, it is argued that the PA only partly achieves the government's intended incentives effects of PA. The regime very well taxes away economic rent as gas price increases, an evidence consistent with the response received by the government in its public consultation (HM Treasury 2013), but offers less and less protection to investors as gas price falls. In addition, there seem to be excessive restrictions in the operational rules of PA that collectively negate its incentive effects. This, we would like to name, a 'Reverse Policy' – one in which the results are inconsistent with government motives. The policy, therefore, needs to be reviewed with urgency in order to render shale gas investment more attractive to fracking majors with the requisite skill, technology and money to invest in the UK.

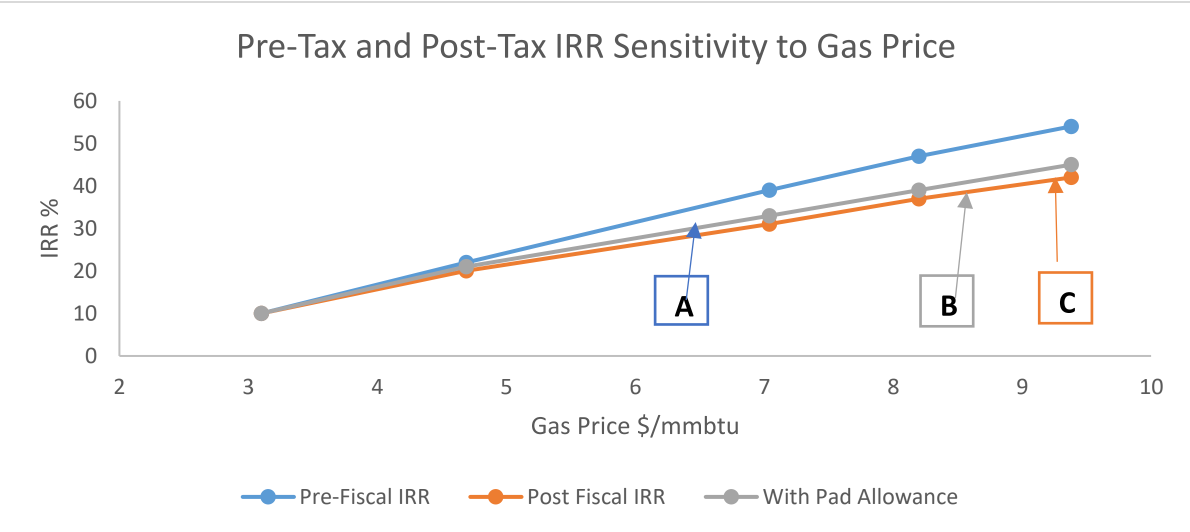

Figure 9: Effects of Gas Price Changes and Pad Allowance on Investor Returns [b]

[b] Figure 9 Shows the relative balance of UK tax effects and also PA effects on investor returns. At lower levels of gas price, all 3 curves almost converge at $3.1/ mmbtu (31 pence per therm). However, as prices increase, the tax burden represented by the gap AB widens more than proportionately, compared to the marginal operator returns represented by the gap BC, implying an imbalance of the split of risk and reward between shale gas investors and the Government. A further test shows the standard deviation of the slope for A, B and C returns 0.70, 0.90 and 0.88 respectively. The investor returns (with PA [B] show the most variability). Thus, instead of stabilising investor returns, the presence of the PA appears to introduce a higher variability of investor returns in response to natural gas price changes. This is contrary to the recommended petroleum fiscal design principle of 'stability'.

UK fracking is widely reported to be unprofitable at typical gas prices. For instance, Bloomberg, in a report to the UK Parliament estimated that it will cost between $7.10 and $12.20/ mmbtu to produce UK shale gas, whilst noting that spot gas price was in the region of $8 to $11/ mmbtu (House of Lords 2013). The Oxford

Institute for Energy Studies estimates the cost of extraction at $8 to $16/ mmcf; EY) estimates at least $8 to $12/ mmbtu whilst Centrica estimates 46 to 66 pence per therm [equivalent to $0.46 to $0.66/ mmbtu[3]] (Boren 2015; Geny 2010; EY 2013). At the same time, these studies report the average natural gas price of less than 50 pence per therm ($5/ mmbtu). In Poland and Germany, EY reports a break even gas price of $8 to $16/ mmcf (EY 2013).

As noted earlier, the US government's tax cuts of 2017 reduced corporate tax rate from 35% to 21%. The tax cut came in recognition of the current market and operational situation of oil and gas business (US Public Law 115-07-Dec. 22, 2017; US IRS 2018), and has resulted in reduced average effective tax rates for the 5 years ending December 31 2017 from negative 14% to positive 31% for some major fracking companies as reported in Appendix 1. The direct response to the initiative was a barrage of announcements of new investments in shale gas and tight oil by major oil companies in the US, with ExxonMobil and Chevron alone pledging a total of nearly $40 billion investment in the Permian Basin - the US's largest hub for shale gas and tight oil between 2018 and 2023 (FT 2018; CNBC 2018; CNBC 2018a; OilPrice.Com 2018). It is worth noting that at the previous 35% corporate tax rate, most fracking giants were reported to be struggling to cover their costs of operation (Forbes 2018).

Table 8 presents a comparative account of selected unconventional oil and gas producing countries and helps to place the discussion in perspective. As Table 8 shows, there are broad similarities but also marked differences between the UK's and other fiscal regimes globally. For example, operators may carry forward losses (LCF) indefinitely in the UK and Alberta, Canada and this is an encouraging feature of the

[3] See Appendices 2 and 3 for conversion approach

fiscal regime. In addition, exploration expenditures may be fully depreciated upon incurring them, whilst the presence of PA and RFES allow UK companies additional deductions which are only found in the Algerian shale fiscal regime. Cost recovery limit (CRL), known to prolong the PBP of investments, carried government participation interests, royalties, and other fiscal features that have been tagged regressive are excluded in the UK fiscal regime. Together, these support the profit-based tax approach of the fiscal regime.

Nonetheless, the UK has the highest definitive tax rate even though there is limited understanding of its resource potential as well as an uncertain fate of production. With 30% RFCT and 10% SC, UK tax is far above the tax rates of the much successful North American shale oil and gas producers at 21%, well progressing Chinese CBM and shale gas development at 25% and the much successful Canadian tar sands and steadily progressing shale gas development. The evidence thus suggests that the UK hopes to tax its fracking industry even more than the much prolific US shale gas, and confirms an industry consultation feedback to the government in 2013 that even with PA, an overall effective tax rate of 40% to 50% would be payable by a company depending on the level set and that was very high. Indeed, this appears to be very high compared to typical rates in the world’s biggest shale gas hub – US, and for the reason of the current market structure with low prices, may not be a competitive or suitable fiscal regime to attract investment.

In addition, although UK compares favourably with best practice on the depreciation of exploration costs, with 100% immediate write off, with its 25% depreciation for P&M costs, it is likely that UK could be relatively at a competitive disadvantage due to the application of RBB of depreciation (See Acquah-Andoh et al. 2019a).

Table 8: Comparative Summary of Fiscal Regimes for Selected Shale Gas States

Parameter	United Kingdom	Pennsylvania	Texas	Alberta	Saskatchewan	Algeria	China
Corporate income tax rate	30%	Federal 21%; State 9.9%	Federal 21%; State 1%	Federal 15%; State 10%	Federal 15%; State 12%	10% – 40%[a]	25%
Additional tax rate	10% SC; on	N/A	N/A	N/A	N/A	15% - 80%[a]	0% - 40%[b]
Depreciation (exploration cost)	100% - immediately	7 years SLB	7 years SLB	100% - immediately	100% - immediately	100% - immediately	3 years SLB
Depreciation of capex	10% RBB for mineral extraction assets; 25% RBB for P&M and long-life assets	IDC - 5 years SLB Non-IDC - 200% accelerated with 7-year SLB	IDC - 5 years SLB Non-IDC - 200% accelerated with 7-year SLB	25% - 30% RBB	25% - 30% RBB	8 years	8 years SLB for pre-production costs; 10 years SLB for others
Additional allowable deduction	10% RFES (uplift of Up to 100% PA could reduce effective tax to 30%	N/A	N/A	N/A	N/A	20% development costs	N/A
Losses carried forward (LCF)	Indefinite	20 years	20 years	Indefinite	Indefinite	5 years	5 years from production start-up
Cost recovery limit	N/A	N/A	N/A	N/A	N/A	N/A	Oil 60%; gas 70%
Royalty	N/A	Oil 12.5%; gas 12.5%	Oil 20%; gas 20%	Oil 0% - 5%; gas 5%-36%[a];	0%-40%[a] Applies to both oil and gas	Oil 5%; gas 5%	Oil 11%; gas 11%
Additional royalty	N/A	$5k - $60K per well for gas; N/A for oil	Oil 4.6%; gas 0%-7.5%[c]	N/A	N/A	N/A	N/A
Guaranteed state share	N/A	N/A	N/A	N/A	N/A	N/A	Min 5%; max 55%
State participation	N/A	N/A	N/A	N/A	N/A	51%[d]	51%

[a] varies with profitability ratio; [b] varies with oil price; [c] varies with cost of well; [d] carried interest until development with repayment; RBB – Reducing balance basis; Straight line basis; IDC – Intangible drilling costs; P&M – Plant and machinery; N/A – Not applicable.

Source: Daniel 2017; EY (2019); US Public Law 115-07-Dec. 22, 2017; US IRS 2018)

Whilst the US and China allow straight line methods of depreciation, over 5 to 8 years for companies to recover their development costs, the UK allows 10% depreciation on RBB for mineral extraction assets, an approach which undoubtedly could defeat an accelerated depreciation policy. Although there are fewer fiscal features in UK's fiscal regime compared to China and Algeria, it is essential that the UK's fiscal policy is benchmarked against the more successful US policy for two reasons: (1) its success with shale gas extraction; and (2) the similarity in geological characteristics between US and UK shale formations (BGS-DECC 2014).

Clearly, the fiscal regime for shale gas has tenets of a LPFR in the sense its tax strategy targets shale gas income rather than revenues, via the PA, RFCT, SC and RFES features. Nevertheless, the regime equally contains quasi proprietorial tax features revealed through the implementation approach of the PA, and the high overall effective tax, which ultimately kill the incentive (i.e. profits reflected in the IRR in Figure 9) to invest and an amendment of the fiscal regime in general is needed. The PA implementaion must be reviewed to allow the transfer of activated PA across companies in the same group and the definition of CAPEX requires an expansion to include mid-life well retirement costs necessary to drill new laterals to stimulate production. Also, a removal of SC from the fiscal regime could potentially simplify the tax regime by removing the distortion it causes to the operator after tax cash flows without economic detriment to the state. Such single line taxation strategy could render the regime more comparable to the practices in more successful countries like the US, China, Algeria and Canada. Ultimately, a reduction in the overall tax for shale gas from 40% to no more than the US rate of 21% is proposed. This would seem reasonable for UK shale gas and could better reward operators under the particular industry circumstances.

5.0 Conclusion and Policy Implications

The UK is believed to hold prolific shale gas reserves. Nonetheless, development progress has been noted to be slow with often cited environmental, health concerns and protests blamed for the slow growth. Meanwhile, more than ten (10) years on, since the government's offering of commercial licenses for shale gas exploration at its 13th Onshore Licensing Round in 2007, the fracking industry is said to have benefited from only £400 million to £500 million investments, and only one (partially) fracked well, with still no certainty yet, of the commercial potential of fracking within UK. The current research focused beyond the often cited environmental protests and planning/ permitting delays for the current fate of shale gas development in UK and explored the likely impacts of the fiscal/ tax regime on the practicality of investments in shale gas in UK. PA and RFES are important features of the UK shale gas fiscal regime. The implications of these incentives as well as the relative burden of the RFCT regime was evaluated. We find that PA and RFES only provide marginal cushioning support to fracking operators. At an average EUR of 7.4 bcf per well, 22.5% higher than the UKOOG's recent estimate of 5 bcf per well and 22% more than the average US (Marcellus) well recovery rate, shale gas investments return unstable economics at typical gas prices, with most scenarios resulting in losses, whilst positive economics are characterised by a long PBP. It is normal for shale gas exploitation projects to have longer PBP, and although the UK Government recognises this situation, the tax incentives package included in the shale gas fiscal regime does not appear to provide sufficient protection for shale gas investments during weak price, low production, or high cost environments. At lower gas price, the tax regime appears to carry a moderate economic burden for operators but at the same time, fiscal incentives also appear to be almost non-existent and hence shale gas investments are not efficient over a wide range of realistic gas prices up to $6.20/ mmbtu at a relatively very high EUR of 7.4 bcf per well. On the other hand, at higher gas prices, the impact of the tax regime becomes quickly noticeable with progressively wider and higher tax costs to operators.

By implication, although the philosophy behind the tax regime appears to derive from profit based taxation principles, the tax approach seems to withdraw support from the industry at lower gas prices at a time when industry would need such support the most in order to survive. We also find that at higher gas prices, operator profits are quickly taxed off more than proportionately from price increases. This mechanism introduces risks to the fiscal regime. As the UK is only an emerging shale gas developer with higher risks around commercial production, Brexit, environmental protests, and more recently seismology challenges, amongst others, we argue that the current fiscal regime appears risky, and less attractive, for investment in shale gas. It is thus likely that UK may have lost potential investments as a result of the fiscal regime and it could lose further investor interests with the current configuration of its fiscal regime for shale gas, especially the delivery of PA.

Although the PA contained within the fiscal regime has been well received by the industry, the same PA has provoked some concerns about its implementation, importantly on how losses from non-performing pads may be recovered by a company or group of companies. Generated PA cannot be transferred across companies in the same group; PA can only be activated three years from the time of investment; RFES does not extend to PA and CAPEX definition excludes mid-life asset retimrement costs required to incur qualifying CAPEX, among other restrictions. In effect, the collective impact of these restrictions appear to negate the incentive effect of PA. In this research, we also find an unfair balance of risk-reward sharing between government and operators within the nascent fracking industry.

The current study evaluated the economic impacts of the UK fiscal regime for shale gas. In addition, it examined the extent of risk–reward sharing between shale gas investors and the UK Government as implied by the shale gas fiscal regime and uncovers an uneven distribution of the risks of developing shale gas as well as the division of profits amongst the Government and industry. Overall, a reduced effective tax rate from 40% to 21% is proposed. In addition, it is recommended that additional tax charges, the SC, be removed from the fiscal regime and PA rules be amended to extend RFES benefits to PA, and allow intercompany transfer of activated PA within the same group in order to better guarantee availability of the allowance. Essentially, a refocused government fiscal strategy which drives more and more investments at the early and relatively riskier stage of industry would be an optimal strategy for the UK government. This approach is practically true for similar emerging countries in Europe and elsewhere that wish to develop their unconventional oil and gas resources.

This study was limited to economic impact analysis of the fiscal regime for shale gas. Future research could survey industry operators and service providers for information on their confidence in the fiscal regime to offer first-hand information to corroborate the findings of this research. In addition, further research that attempts to model fiscal scenarios that better distribute risks and rewards of developing shale gas fairly would support the UK Government's efforts to stimulate investment in shale gas development.

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