

Economic Evaluation of Bowland Shale Gas Wells Development in the UK

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Abstract—The UK has had its fair share of the shale gas revolutionary waves blowing across the global oil and gas industry at present. Although, its exploitation is widely agreed to have been delayed, shale gas was looked upon favorably by the UK Parliament when they recognized it as genuine energy source and granted licenses to industry to search and extract the resource. This, although a significant progress by industry, there yet remains another test the UK fracking resource must pass in order to render shale gas extraction feasible – it must be economically extractible and sustainably so. Developing unconventional resources is much more expensive and risky, and for shale gas wells, producing in commercial volumes is conditional upon drilling horizontal wells and hydraulic fracturing, techniques which increase CAPEX. Meanwhile, investment in shale gas development projects is sensitive to gas price and technical and geological risks. Using a Two-Factor Model, the economics of the Bowland shale wells were analyzed and the operational conditions under which fracking is profitable in the UK was characterized. We find that there is a great degree of flexibility about Opex spending; hence Opex does not pose much threat to the fracking industry in the UK. However, we discover Bowland shale gas wells fail to add value at gas price of \$8/ Mmbtu. A minimum gas price of \$12/Mmbtu at Opex of no more than \$2/ Mcf and no more than \$14.95M Capex are required to create value within the present petroleum tax regime, in the UK fracking industry.

Keywords—Capex, economical, investment, profitability, shale gas development, sustainable.

I. INTRODUCTION

THE UK has long had the potential to extract shale gas but policymakers treated this as a non-existent opportunity [1] relative to more conventional hydrocarbon resources until a recent shift in focus, to meet part of the country's growing energy needs from unconventional sources. In consequence parliamentary sanction for a campaign for shale gas exploration in the UK led to the award of blocks for the exploration of shale gas during the country's 13th Round of Onshore Licensing in 2008 [2]. While this is a major milestone attained by the fracking industry, there yet remains other hurdle that must be managed in order to render shale gas production in the UK sustainable - high capex that characterize shale gas reservoirs.

This paper presents an evaluation of the economic viability of a commercial scale extraction of the Bow land shale gas play using the Two-Factor Model applied by [3] in a similar work on Haynesville shale gas wells in the US. NPV, IRR and Parameter Sensitivity Analysis are used as decision outputs to

assess the conditions under which investment in Bow land shale gas play and hence production of the same would be economical and sustainable.

The rest of the paper is organized as follows. Section II offers some background to the Bow land shale play and summarizes the UK's petroleum tax regime, Section III presents our economic model, major cost components and results from production simulation, Section IV presents and discusses the results, and Section V concludes.

II. THE BOWLAND SHALE PLAY AND THE UK PETROLEUM TAX REGIME

A. The Bowland Shale Gas Play

The British Geological Survey (BGS) produced a report for the Department of Energy and Climate Change (DECC) in 2012 in which it identifies the geological maps where Britain's most prolific shale gas potential is located. Geological models indicate that carboniferous organic rich basinal marine shale formations are present in the Bowland- Hodder unit of Central Britain among others running roughly through North-East England to the South and South-West coast [2] (Fig. 1). Of the basins assessed by the British Geological Survey in 2010, the Bowland Basin (Fig. 2) was the largest in the assessment area, continuing westwards below the Irish Sea, where the Upper Bowland Hodder, is a source rock for conventional fields [2].

TABLE I
TOTAL GIP AND RECOVERABLE RESERVES [2], [4]

	Total gas in-place estimates (tcf)			Total gas in-place estimates (tcm)		
	Low (P90)	Central (P50)	High (P10)	Low (P90)	Central (P50)	High (P10)
Upper unit	164	264	447	4.6	7.5	12.7
Lower unit	658	1065	1834	18.6	30.2	51.9
Total	822	1329	2281	23.3	37.6	64.6

A 2013 BGS/DECC report presents a preliminary assessment of the gas – in – place (GIP) for the Bowland shale gas play. In this initial assessment the DECC reports that potential shale gas resources could reach 1,329 tcf (Table I) with an organic content in the range of 1% - 3% or even up to 8% [2]. In this assessment DECC thinks that the Bowland shale is prolific and draws a potential comparison between the Bowland and Barnette shale and estimates that if the two are equivalent then the former could yield up to 4.7 Tcf as its central estimate of recoverable reserves, in instances where organic material have been buried to sufficient depths to generate gas [2]. Table II summarizes some current general information available concerning the nature of the Bowland

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and other UK play with the proven shale gas plays of North America.



Fig. 1 Location of the BGS/DECC shale gas study area - central Britain [2]

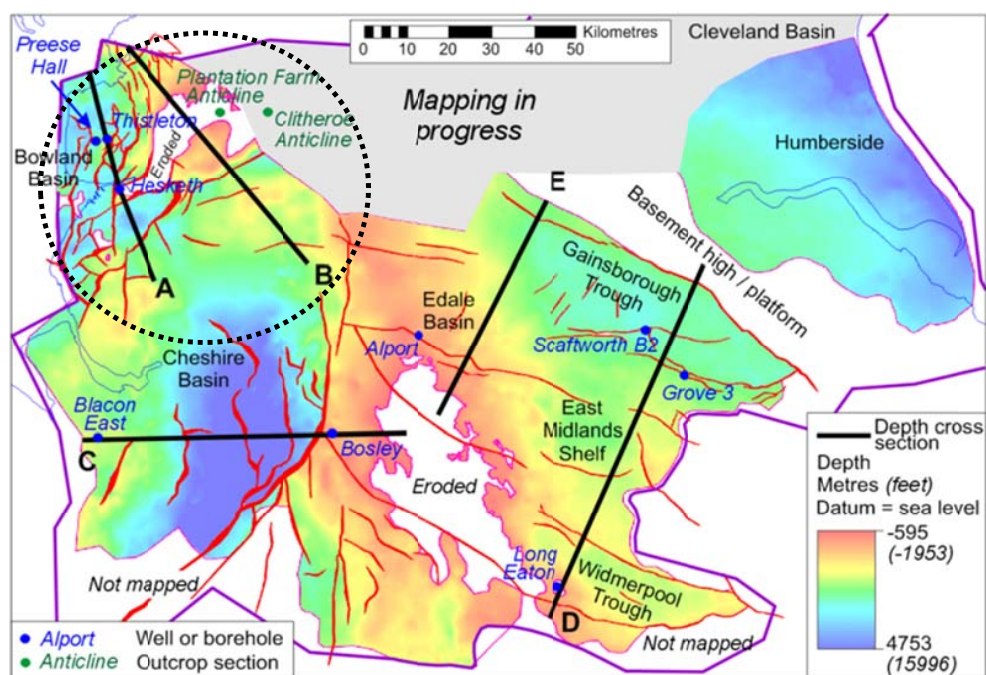


Fig. 2 Values Depth to the top of the Bowland-Hodder unit [2]

TABLE II

SUMMARY OF POSITIVE, NEGATIVE AND UNKNOWN OR POORLY KNOWN FACTORS AFFECTING THE UK'S CARBONIFEROUS POTENTIAL SHALE GAS PLAY [2]

Positive factors	Negative factors	Unknown or poorly known
Thickness of >2% TOC intervals	Variable organic content in lower unit isopach thick areas.	Limited well penetrations in lower unit isopach thick areas.
Some Type II kerogen	Some Type III kerogen	Gas yield
Brittle shale (interbedded w/brittle limestones)	Structural complexity and inversion	IP and decline rate
Thermal maturity >1.1 R_0 >3.5 R_0	Relatively low gamma response compared to North American analogues	Extent of over-pressuring
Evidence of gas in shale wells and producing fields sourced from Bowland Shale	Lower unit isopach thick areas have no North American shale gas analogues	

The first shale gas well to be hydraulically fractured in the UK, Cuadrilla Resources Ltd.'s Preese Hall 1 well is located in its 500 square mile block in the Bowland basin in Western Lancashire [2], although operation at PH1 were suspended following two induced minor earthquakes of 2.3 ML and 1.5 ML magnitudes in the Blackpool area [5]

B. The UK Petroleum Tax Regime

The current petroleum tax regime of the UK comprises 3 major elements- ring fence corporation tax RFCT, supplementary charge, SC and petroleum revenue tax (PRT) [6]. RFCT works in similar ways as traditional corporate tax, except that RFCT restricts the extent to which taxable profits from oil and gas operations in the UK and UK continental shelf may be applied to recover finance costs and losses from "other operations". An oil and gas operator may recover 100% of drilling and completions costs incurred in the first year of operations from profits chargeable to RFCT [7]. SC makes further charges on an operator's RFCT but without allowance for interest costs. SC has been fairly stable over the years until recently. It was increased from 20% from 24th March 2011 to 32% till 31st December 2014. The current SC is 20% effective 1st January 2015 [7]. PRT only applies to fields that were

given development consent before 16th March 1993 and is thus not covered here (see [7] for further detail).

The UK's shale gas industry is very young and government proposals thus far point to a commitment to offer incentives to industry to stimulate investments at this early stage. The outcome of a 2013 government consultation with industry on a proposed fiscal regime for shale gas includes a proposal of shale gas pad allowance which aims to exempt part of a company's profits chargeable to SC and reduce the effective tax to 30% [6] as well as an the carrying forward of, and uplifting unrecovered first year capex at 10%. These incentives are only at the proposal stage. In consequence, at present it is clear from the UK Government that profits from shale gas production would be subject to the RFCT regime for conventional oil and gas.

The economic model used in this study assumes the present "ring fence tax" regime with an effective tax of 44% ($30\% + 20\% \times (1-30)$); RFCT of 30% and SC of 20%. First year unrecovered capex are carried forward and uplifted at 10% for a maximum of 10 years [6]. Fig. 3 summarizes the tax framework used in modelling the project cash flows.

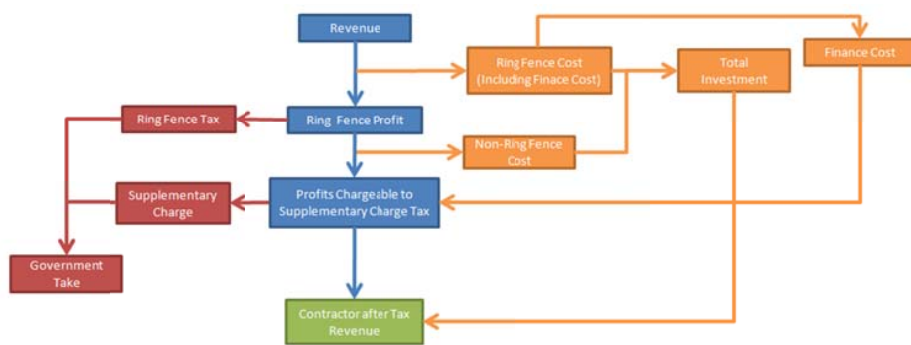


Fig. 3 Petroleum Tax Framework [6]-[8]

III. ECONOMIC MODELLING

A. Investment Decision Criteria

The decision to invest in the Bowland shale was evaluated based on a discounted cash flow valuation. All cash flows arising from the shale gas project were forecast and discounted using an assumed cost of capital and discount factor of 10% to account for the time value of money. A decision variable, the NPV was then derived from (1) as the sum of the discounted cash inflows and outflows over the project life. The NPV is sensitive to the discount rate and could change the economics and acceptability of a project drastically, hence a lower discount rate; and cost of capital is usually better preferred as it generally favors the acceptability of projects.

$$NPV = \sum_{t=1}^T \frac{X_t}{(1+\mu)^t} \quad (1)$$

where X_t represents the project net cash flows and μ represents the cost of capital. Another decision variable used

was the IRR which calculates the rate of return at which the NPV is zero. The decision criteria used was to reject the NPV if it is negative and reject the IRR if less than the cost of capital or a company's expected return from capital projects. Further decision variables focused on measuring the efficiency of investments in the Bowland shale as well as risk factors and these are discussed further in the sections that follow.

B. Production Profile

Regeneris and Cuadrilla Resources Ltd. [9] investigated 3 possible drilling scenarios assuming 10 wells per pad and simulating across several pads found that it was possible to drill 400 wells using 20 pads in 9 years assuming there is a build-up of activity in the initial years. Shale gas wells have a much shorter lifespan and peak quickly although they have a high initial flow rate [10].

In order to maintain and grow production additional wells need drilling each year and this is a substantial ongoing capital requirement. "Production in shale plays can certainly grow

very rapidly; but drillers' experience so far shows that maintaining very high rates of production for years—let alone decades—is no sure thing” [10, p. 5]. For this reason, we assume averages of 58 new wells, with a spacing requirement of 40 acres, are brought on stream each year in our model in order to maintain and grow production. A total of 1,160 wells were assumed to be invested in over the life of the project. Beyond year 20 it is assumed further investment is uneconomic because sweet spots have been exploited and further investment results in lower and lower rate of return. Production from already completed wells just before year 20 will however continue until year 30, bring our central cumulative production from the field to 4 Tcf; an average well production of 3.4 Bcf over 30 years. This is equivalent to the performance of the average well of the top 7 shale plays in the US [10].

Table III summarizes key assumptions and Fig. 4 presents the resulting graph from our production simulation. Initial flow rates for shale gas wells are typically high but rapidly decline later before flattening out over the life of the well [11] [10]. Since initial production rates are unknown for the Bowland shale, we have assumed this as 3,666 Mcfd for our central scenario.

US shale gas wells declined at 23% in 2001 [12] but declined between 32% and 42% in 2012. It is noteworthy that these decline rates are a function of the geological and geophysical characteristics of the shale play and here again similar properties have been assumed for the US shale and Bowland shale. A decline rate of 40% was assumed for the Bowland shale wells.

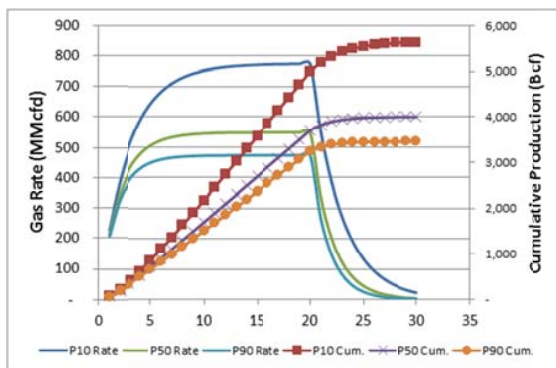


Fig. 4 Simulated Production Profile for the Bowland Shale Gas Play

C. Major Cost Components and Gas Price

1. Land Acquisition Cost

The UK oil and Gas Licensing Regime however requires operators to secure access rights from the legal owners of onshore lands and adjacent lands, separately for the purposes of drilling wells [13], [14]. Land acquisition costs can be a good part of the cost of onshore drilling expenditure. In the US these have been as ranging between \$3000 per acre and \$25,000 per acre. In this paper, land acquisition costs are assumed to be \$11,700 (£7,000) per acre. All major costs involved in this work, their distribution and all relevant

assumptions have been explained below

2. Capital Expenditure (CAPEX)

Capital expenditure for a shale gas project comprises well drilling and completions costs, pipeline infrastructure costs, road construction costs, land acquisition and permitting costs, geological and geophysical costs and related facility costs. Although capex spending depends on the specific subsurface properties and technological solutions, [3] notes that the average US shale wells in the Haynesville ranged between \$7M and \$10M in 2010. Ernst & Young [15] estimate £330M per well pad with 10 vertical wells and 40 laterals in a pad; i.e. each 1 vertical well has 4 laterals and they cost £33M, resulting in average well cost of £6.6M. Similarly, in this paper, a 10 – well pad drilling program is assumed with each pad comprising 1 vertical well and 4 laterals of an average length of 4000 ft. and each is assumed to cost between £8.97M and £12M comprising site preparatory work for permitting, drilling and related costs and fracking and related costs including technical testing costs. These have been converted into dollars using 2013 exchange rate at \$/ £0.60 [9] and escalated at 3% per annum to allow for inflation. Regenris and Cuadrilla [9] estimate that additional infrastructure costs comprising the cost of producing, supplying and installing gas conversion as 15% of drilling and fracturing costs and Peel Gas and Oil Ltd. [16] predicts £5M per well pad site. Although in this paper we assume gas produced from the Bowland shale is largely dry, a related capex factor of 15% is assumed each year to cater for minor additional surface facility costs such as well stimulation costs, manifolds and flowlines to connect to main UK gas pipeline and or to construct electricity generation plant at each well pad site and to connect to the national grid. We assume there is no requirement for the construction of a central treatment facility. The full range of capex assumptions are summarized in Table III. Capex is depreciated at 20% on straight line basis.

3. Operating Expenditure (OPEX)

UK shale gas is currently at its exploration phase. It is therefore difficult to source actual operating costs from industry relating to shale gas licenses with any accuracy. Opex comprises a fixed expenditure per well per year as well as variable Opex to cater for gathering, compression and (treatment where required). IoD [17] estimate fixed Opex for the Bowland shale at £0.5 M and variable Opex at 2.5% of cumulative capex per year. Kaiser [3], however, while studying the economics of Hahnville shale in the US, noted that average Opex were \$0.85, \$0.80, and \$0.50, per Mcf in 2008, 2009, and 2010 respectively. Browning, Ikonnikova, Gulen and Tinker [11] report \$25,000 fixed Opex per year plus 13% overheads and a variable Opex of \$1.66/ Mcf and a one-off abandonment cost of \$75,000. In this paper, variable Opex is assumed at \$1.5/ Mcf for the P50 well and a fixed annual Opex of \$25,000 plus 15% overhead. These will cater for water disposal, gathering, and depletion. Dry gas is cheaper to produce and we assume the need for surface equipment for separation is removed. Abandonment costs are

included in the well cost.

Opex is assumed to increase over a well's life due to equipment repair costs, water treatment and disposal costs, and costs arising from the need for compression and maintenance. The central case Opex used in this paper is \$1.5/Mcf and an Opex escalation of 3% *per annum* was assumed.

D. Natural Gas Price

Shale gas development proposals may receive a final investment decision (FID) or may be suspended or delayed due to the gas price to be received from gas sales and or the (un)certainly surrounding the price. Shale gas price is affected by the same factors that affect conventional gas price [3]; hence we apply the DECC's projections for conventional gas price to the Bowland project. The UK prices gas in pence per Therm. These have been converted into \$/MMBtu at 10.028 using Barclays Bank's \$/£ exchange rate forecast of \$1.54/£. Gas prices are escalated at 3% per annum to cater for inflation. The central case gas price used is \$9.55/MMBtu.

E. The Two-Factor Model

The development of shale gas wells very much depends on gas price [3], [11], [10] in addition to a host of other factors including Opex, Capex, production volumes, etc. The effects of variations in these input parameters on the decision to develop the Bowland shale wells was evaluated using the sensitivity of the project NPV and IRR. The method of sensitivity analysis applied here follows the concepts laid out in the Two-factor model used by [3] to appraise the profitability of Haynesville shale gas wells in the US. The output from a discounted cash flow analysis for 3 production well scenarios following the triangular distribution (P10, P50 and P90) was used to quantify the complete range of prospective outcomes of the project. The P50 represents the average and most likely case while the defined expected boundaries for all outcomes were represented by the P10 (optimistic outcome) and P90 (pessimistic outcome). P10 production profile yields the most favorable economics whereas the P90 results in the least favorable economics, with the scale of the differences between these 2 scenarios indicating possible sets of results as well as the possible risks and rewards to the project. Here, we use the project input parameters to capture the operating conditions under which the shale gas production from the Bowland shale is economically viable. Table III summarizes the input parameters and their notations. The input variables are combined thus; gas price and capex, gas price and Opex, and Opex and capex. Every other variable is held unchanged and output variables are NPV and IRR. Tables IV–VIII present the results.

IV. RESULTS

A. Results of the DCF Analyses

In this section we present results of the 30-years DCF model to evaluate the economic viability of Bowland shale gas wells.

TABLE III
ECONOMIC MODEL PARAMETERS

Parameter	Notation	Unit	Minimum	Maximum
Well Cost	CAPEX	\$MM	14.94	20
Operating Expenditure	OPEX	\$/Mcf	1	2.5
Gas Price	GASP	\$/MMBtu		15.83
Land Acquisition	LANDA	\$M/ ac	6.67	16.67
Well Spacing	WELSPC	ac	40	40
Cost of Capital	COSCAP	%	10	10
Ring Fence Corp Tax	RFCT	%	30	30
Supplementary Charge	SC	%	20	20
Initial Production	IP	Mcf/d	3,555	3,878
Gas Price Escalation	GASPe	%	3	3
Opex Escalation	OPEXe	%	3	3
Capex escalation	CAPEXe	%	3	3

The pre-tax results indicate acceptable economics for the Bowland shale gas wells with P50 wells yielding a NPV @ 10% of \$3.6 billion and an IRR of 22%. The total investment of \$20.4 billion in 1160 wells in this scenario is recouped in approximately 6 years from production and renders the project very competitive with a breakeven gas price of \$7.69/MMBtu. The post – tax results, however, are markedly *unfavorable* for the central scenario with a negative NPV of \$1.9 billion and a breakeven gas price of more than \$11/MMBtu. The IRR is 2.5% and thus given cost of capital of 10%, this renders the project uneconomical. We attribute this to the present petroleum tax environment in which shale gas finds itself. We argue that the present tax regime is unfavorable for the fracking industry which unnecessarily introduces a high degree of uncertainty in an operator's cash flows. In contrast, the P10 results are far more robust and better than the P50 economics. This is due to the *favorable* reservoir conditions assumed for the present scenario with an annual decline rate of 30%. This rate is typical of US shale plays [11], [18] and thus can be thought of as a very much conservative assumption for our P10 scenario, if indeed the Bowland shale is equivalent to prolific shale plays in the US per BGS/ DECC's prediction. The post-tax NPV now recovers from negative in the P50 scenario and sits at about \$15 billion with pay out occurring in just about 3 years with a breakeven gas price of \$5.77/MMBtu and an IRR of 75%. This economics is very much robust and supports any argument to invest in the Bowland shale play. P90 economics are just prohibitive of any investment in the Bowland shale with a post –tax breakeven price of \$17.45/MMBtu. It is significant to note, however, that the present petroleum tax regime appears to be regressive in the shale gas environment. The P50 case results in Government Take of approximately 90% and leaves the fracking company just about 10% cash flows, which is insufficient to even cover their investment. The P10 scenario which is much more economically profitable sees the Government Take reduce overwhelmingly by approximately 40%. If not addressed this will be a major obstacle to the development of the Bowland shale gas and the UK's shale gas in general as such a regressive fiscal environment has been found to discourage investments in hydrocarbons – leaving suboptimal benefits to the government and contractor in the

long term [19] [20]. Even though the shale gas fiscal regime is still under creation in the UK, it will be very necessary to introduce high order progressive features to offset any tendencies of discouraging capital spending by the fracking companies within the tax framework. We therefore highlight here that the post-tax economics of the Bowland shale play are not very stable as much as they are robust for the pre-tax results. We attribute this to the application of the conventional oil and gas tax regime, which has rather proved regressive, to the shale gas industry and wish to mention that once resolved investment in the Bowland shale, should be very much viable. Government take is very high during low price, high cost environment but overwhelmingly shrinks during favorable economic environments.

TABLE IV
PRE-TAX ECONOMICS FROM DCF ANALYSIS

Economic Indicators	Unit	P ₁₀	P ₅₀	P ₉₀
Pre-Tax				
POT	Year	1.26	5.96	n/a
NPV at 10%	MM\$	31,269	3,635	(8,736)
IRR	%	125.36	22.35	n/a
Economic Limit	Year	30	30	25
Break Event Gas Price	\$/MMBTU	3.98	7.69	11.93
Post-Tax				
POT	Year	2.71	20.97	n/a
NPV at 10%	MM\$	14,921	(1,944)	(10,465)
IRR	%	75.55	2.53	n/a
Economic Limit	Year	30	27	25
Break Event Gas Price	\$/MMBTU	5.77	11.30	17.45
Government Take	%	49.24	89.77	n/a
IOC Take	%	50.76	10.23	n/a

B. Gas Price and Capital Expenditure Sensitivities

Table V summarizes the results from modelling the sensitivity of gas price and capital expenditure variations alone. This enabled the capturing of the implications of differing gas prices scenarios for investment requirements and hence a measure of the risks and rewards for any investment in the Bowland shale wells as indicated by the elasticity of the NPV to such variations. Every other model parameter was held constant as follows; \$11,670/ ac for land acquisition costs, 40 acre well spacing, \$1.5/ Mcf for operating expenses and 10% cost of capital.

At \$4/ MMBtu gas price, the project fails to be profitable under all CAPEX scenarios for all well types, including P10 wells. Operators are thus unlikely to hold their acreage under low gas price conditions. Given, the lower levels of losses for lower CAPEX scenarios such as \$5MM and \$10MM, a risk-taking and highly efficient operator may wish to use their expertise to drill sweet spots in order to leverage their costs and produce high quality shale. Similar to Kaiser's [3] discovery in his Haynesville shale study, if wells in such a low price environment turn out to be average producers then the Bowland shale will not be profitable in such environments.

At \$8/ MMBtu gas price, most wells types are still uneconomical under most capex scenarios although P10 wells may be brought on stream at \$10 MM for a marginal NPV of

\$2.27 billion and \$5.73billion at \$5MM. It appears that in order for an operator to produce the P50 and P90 wells, they have to be very much cost efficient and leverage any geological challenges that may come with shale gas extraction in the Bowland basin.

At gas price of \$12/ MMBtu and higher, P10 wells are economical for most capex scenarios, except for \$20MM. P50 wells are mostly profitable but only fairly so in relation to P90 wells.

Important from the foregoing is that the Bowland shale wells cannot be developed for less than \$10MM in a low price environment. Given that investment in shale gas wells are typically much more expensive, low gas price prohibits investing in these wells for most scenarios. These must be managed in order to render shale gas extraction attractive enough, especially as gas from shale has to compete against conventional gas.

TABLE V
GAS PRICE, CAPEX SENSITIVITY ANALYSIS

NPV (Gas, CAPEX) Sensitivity Analysis (\$ Billions)					
P10, OPEX = \$1.5/Mcf					
Gas Price (\$/MMBTU)	CAPEX/Well (\$MM)				
	5	10	15	20	25
4	-0.23	-2.00	-7.25	-9.98	-14.00
8	5.73	2.27	-1.21	-4.70	-8.16
12	11.67	8.21	4.75	1.29	-2.18
16	17.58	14.15	10.69	7.23	3.77
P50, OPEX = \$1.5/Mcf					
Gas Price (\$/MMBTU)	CAPEX/Well (\$MM)				
	5	10	15	20	25
4	-1.22	-4.76	-7.73	-11.76	-15.82
8	3.25	-0.22	-3.71	-7.15	-10.73
12	7.66	4.20	0.74	-2.70	-6.21
16	12.06	8.62	5.16	1.70	-1.76
P90, OPEX = \$1.5/Mcf					
Gas Price (\$/MMBTU)	CAPEX/Well (\$MM)				
	5	10	15	20	25
4	-1.57	-5.08	-8.37	-12.41	-16.49
8	2.36	-1.11	-4.61	-8.11	-11.65
12	6.23	2.77	-0.70	-4.17	-7.67
16	10.09	6.64	3.18	-0.29	-3.75

C. Gas Price and Operating Expenditure Sensitivities

In Table VI, the impact of gas price and Opex sensitivities is measured. Here, capex is fixed, just as every other input variable as before, at \$14.95MM per well. Well spacing is fixed at 40 acres and land acquisition cost of \$11,670/ ac is used.

P10 and P50 wells fail to create value under all capex scenarios at \$4/ MMBtu and \$8/MMBtu, except for P10 wells that are marginally profitable at \$8MM and \$0.50/ McfOpex. Both well types are profitable at gas price of \$12/ MMBtu and higher for almost all Opex scenarios, except for P50 wells that may be brought on stream for slightly less than \$2.5/ Mcf. It is noteworthy that the white portion of the matrix representing the profit window is larger for the present analysis than it was for the "Gas price, Capex" analysis. This is indicative of the fact that the Opex chosen for our analysis is favorable and that

Opex may not be a big hindrance to the development of shale gas in the Bowland basin. When gas price is \$12/ MMBtu P10 wells are profitable across the entire matrix. P50 wells may also be brought in for all Opex scenarios up to a little under \$2.5/Mcf. Such a wide variation in Opex allows the operator a high degree of flexibility in spending and project management in order to create value/ make profits. It appears that the safety net for making Bowland shale profitable under Opex scenarios is gas price of \$12/ MMBtu and opex of not more than \$2/ Mcf. P90 wells are not profitable for the most part of the analysis except at gas price of \$16/ MMBtu and across the entire Opex range.

TABLE VI
GAS PRICE, OPEX SENSITIVITY ANALYSIS

NPV (Gas, OPEX) Sensitivity Analysis (\$ Billions)					
P10, CAPEX= \$ 14.95MM					
Gas Price (\$/MMBTU)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
4	-5.76	-6.50	-7.21	-7.29	-8.67
8	0.29	-0.44	-1.17	-1.90	-2.64
12	6.23	5.51	4.79	4.07	3.34
16	12.17	11.45	10.72	10.00	9.28
P50, CAPEX= \$ 14.95MM					
Gas Price (\$/MMBTU)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
4	-7.13	-7.64	-7.69	-8.73	-9.81
8	-2.58	-3.13	-3.68	-4.22	-4.77
12	1.85	1.31	0.78	0.24	-0.30
16	6.27	5.73	5.19	4.66	4.12
P90, CAPEX= \$ 14.95MM					
Gas Price (\$/MMBTU)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
4	-7.64	-7.43	-8.33	-9.25	-10.24
8	-3.62	-4.10	-4.58	-5.06	-5.51
12	0.28	-0.19	-0.66	-1.13	-1.60
16	4.15	3.68	3.21	2.74	2.27

D. Capital Expenditure and Operating Costs

In this section we fix gas price at \$9.55/ MMBtu, \$11,670/ ac. Well spacing, 10% cost of capital, and 44% effective tax rate. Table VII presents the results. P10 and P50 wells see a broader profit window in this analysis. Value is created across all Opex scenarios at a maximum capex of \$10MM per well. P90 wells are not profitable here but markedly improve to create value across all Opex scenarios at capex of \$5MM and at \$10MM for \$1.5/ Mcf or less.

At \$15MM capex and \$0.50/ McfOpex, there is a loss of \$2.11 billion recorded. As capex reduces by 50% to \$10MM but Opex triples to \$1.50/ Mcf, we see a remarkable increase in NPV to +\$0.40 billion. A further 50% reduction in capex to \$5MM and a 50% increase in opex see even bigger increase in NPV to \$3.39 billion, an increase of 747.5%. This further supports the earlier discussion that Opex is not a critical problem for the development of the Bowland shale. In the present analysis the reduction in capex very much overwhelms the tripling up of the Opex each time and results in higher and higher NPVs.

TABLE VII
CAPEX, OPEX SENSITIVITY ANALYSIS

NPV (CAPEX, OPEX) Sensitivity Analysis (\$ Billion)					
P10, Gas Price= \$ 9.55/MMBTU					
CAPEX (\$MM)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
5	9.48	8.75	8.03	7.31	6.59
10	6.02	5.30	4.57	3.85	3.13
15	2.56	1.84	1.12	0.39	-0.34
20	-0.91	-1.64	-2.37	-3.10	-3.83
25	-4.40	-5.13	-5.86	-6.59	-7.32
P50, Gas Price= \$ 9.55/MMBTU					
CAPEX (\$MM)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
5	6.03	5.49	4.96	4.42	3.88
10	2.57	2.03	1.50	0.96	0.42
15	-0.89	-1.42	-1.97	-2.52	-3.06
20	-4.38	-4.92	-5.47	-6.01	-6.56
25	-7.87	-8.42	-8.96	-9.45	-10.07
P90, Gas Price= \$ 9.55/MMBTU					
CAPEX (\$MM)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
5	4.80	4.33	3.86	3.39	2.92
10	1.34	0.87	0.40	-0.08	-0.54
15	-2.11	-2.61	-3.09	-3.56	-4.04
20	-5.63	-6.10	-6.58	-7.06	-7.54
25	-9.12	-9.60	-10.03	-10.57	-11.07

E. IRR Sensitivity Analysis for P50 Profiles from Tables IV - VII (Percentage)

Table VIII shows the results of post-tax IRR for all P50 wells presented in Tables IV–VII. The results indicate the broad envelope of returns and are consistent with the NPVs discussed earlier. Project returns are very high at gas price of \$12/ MMBtu and capex of no more than \$20MM at Opex of \$1.5/ Mcf. Also, value is created at gas price of \$8/ MMBtu and Opex of \$1.5/ Mcf with a capex of \$10MM or less. At the average Capex of \$14.95MM, value is created throughout all Opex scenarios with gas price of \$12/ MMBtu or higher. The average gas price used in our model, of \$9.55/ MMBtu is still profitable at capex of \$15MM and Opex of \$1.5/ Mcf. Also, an increase in Opex of up to \$2.5/ Mcf with a reduction in Capex to \$10MM and subsequently to \$5MM at Opex of \$9.55 present a post-tax IRR of up to 43%. This is remarkable performance and brightens the prospects for the development of the Bowland shale. It is significant to note, however, that at gas price of \$8/ MMBtu or less almost all the matrix is shaded grey for all capex scenarios and the profit window disappears. These regions (marked n/a) are characterized by large negative returns/ huge losses as the projects fail to even break even. Thus although there are good prospects in the Bowland shale play, low gas prices render production of the play economically unsustainable. It is noteworthy that an effective tax of 44% may be too high for the fledgling fracking industry and if shale gas production is to be sustainable in the UK, a large incentive that rewards efficiency and technological advancements, geared towards a low Capex future for the fracking industry.

TABLE VIII
POST-TAX IRR FOR ALL P50 PROFILES

IRR Post-Tax Sensitivity Analysis for P50 Profiles (%)					
P50, OPEX = \$1.5/Mcf					
Gas Price (\$/MMBTU)	CAPEX/Well (\$MM)				
	5	10	15	20	25
4	n/a	n/a	n/a	n/a	n/a
8	35.24	8.84	n/a	n/a	n/a
12	65.58	31.00	12.78	2.03	n/a
16	93.43	51.93	28.88	14.93	5.82
P50, CAPEX= \$ 14.95MM					
Gas Price (\$/MMBTU)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
4	n/a	n/a	n/a	n/a	n/a
8	n/a	n/a	n/a	n/a	n/a
12	16.90	14.91	12.92	10.90	8.87
16	32.92	30.99	29.06	27.12	25.18
P50, Gas Price= \$ 9.55/MMBTU					
CAPEX (\$MM)	OPEX (\$/Mcf)				
	0.5	1	1.5	2	2.5
5	54.52	50.86	47.18	43.47	39.73
10	23.09	20.43	17.75	15.02	12.23
15	6.62	4.58	2.45	n/a	n/a
20	n/a	n/a	n/a	n/a	n/a
25	n/a	n/a	n/a	n/a	n/a

V.CONCLUSION

The discovery of shale gas in the UK has aroused keen interests from across industry, academia and not for profit organizations. Although, the development of shale gas is largely agreed to have been delayed, there is now momentum in what the UK looks forward to in deriving gas supplies to augment its energy needs, create jobs and generate revenues to the exchequer. For industry, shale gas has, although has lower exploration risks and is mined onshore, the resource is expensive to extract. We presented a characterization of the operating conditions under which the most prolific UK shale gas play, the Bowland shale, would be economically sustainable. Pre-tax economics are generally highly economical with an IRR of up to 125% in our P10 scenario. It is however unfortunate as post-tax economics are not encouraging enough. In our P50 analysis, the project fails to return the cost of capital with only 2.53% IRR at \$9.55/MMBtu gas price and a realistic capex of \$14.95 per well.

Break even costs are generally between \$0.5 and just under \$2.5/ Mcf for most cost scenarios. Operators thus have a great degree of flexibility in managing Opex. The safety net for making Bowland shale profitable under Opex scenarios is gas price of no less than \$12/ MMBtu and Opex of no more than \$2/ Mcf at \$14.95MM capex.

We analyzed pre-tax and post-tax economics as well as government take outputs and find that government take is rather unacceptably high at 90% in low-price/ high cost environment, leaving the operator with a huge loss and an IRR of 2.53%. In a profitable environment however, the government take dropped sharply by 40% whereas the operators IRR recovered quickly to 75%. We attribute this to the application of the conventional oil and gas tax regime,

which has rather proved regressive, to the shale gas industry but we wish to add that once resolved investment in the Bowland shale will be very much viable and sustainable.

Finally, at realistic gas price of \$8/ MMBtu or less the Bowland shale play fails to create value in the present tax environment. There is a potentially bright operational future for the Bowland shale play; however, it appears that low gas price render production of the play economically unsustainable under the present ring fence petroleum tax regime.

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