Submission to the Scottish Government consultation on unconventional oil and gas

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EXECUTIVE SUMMARY

The Minerals Section of Planning Practice guidance of 2014 defines unconventional hydrocarbon resources, or unconventional oil and gas (UOG) in an unsound way. The definitions used in the Scottish Government (SG) consultation paper and the KPMG report commissioned by the SG are better but still incomplete. I have reviewed the literature to arrive at a scientific definition for UOG, which requires that: the host rock permeability be less than 0.1 mD; it has a diffuse or non-defined distribution, in contrast to a conventional trap; and it requires stimulation to make the fluid flow. The SG definition of hydraulic fracturing includes all types of wells; the Infrastructure Act definition of fracking of shale uses a definition based on water volume used of 10,000 cu. m per well, which has no sound basis. If water use is to be the criterion, I show from a recent US study of more than a quarter of a million fracked wells that horizontal shale fracked wells for oil use more than 2000 cu.m and for gas 2500 cu.m, so these are robust volume thresholds with which to define shale fracking, which is High Volume Hydraulic Fracturing, or HVHF.

Local authorities are required to draw up mineral plans consistent with national guidance, including the unsound definitions of UOG and of shale fracking. I submit that they should modify or ignore these aspects of the guidance. National energy policy dates back to the 2007 white paper 'Meeting the energy challenge'. This is also unsound because the paper pre-dates UOG. Other aspects of the paper, including the question of stability of gas imports, are also out of date. Given current and predicted gas import supplies, there is not the supposed gas supply crisis in the UK during the next 10-20 years that proponents of UOG assert. Therefore there is no valid reason to develop the new and polluting form of energy industry that is UOG.

In complex geology such as the UK shale basins there is a real risk of contamination of shallow groundwater resources from deeper UOG activities, in part because geological faults may act as conduits. Several separate computer modelling studies now confirm this possibility. It is a separate issue from that of fracking-induced triggering of small earthquakes, which I do not consider to be a problem. But faulting is consistently underplayed by the shale developers. The government has avoided defining a safe distance between shale fracking and nearby faults, probably because to do so would rule out practically all UK shale basins from UOG exploitation.

Wastewater (*flowback* from fracking, along with that *produced* by subsequent production) has not been addressed. The Environment Agency is now in favour of underground re-injection, which is known to trigger severe earthquakes, and marine dumping has been mooted. The latter is probably illegal under international conventions even if the dumping takes place in inland waters. The residual acrylamide contained in the polyacrylamide used in slickwater fracking is highly toxic, and can return to contaminate groundwater in possibly local and concentrated volumes, sufficient to be toxic.

The economics of UOG do not work. Gas imports are and will continue to be cheaper than the price achievable by a domestic UOG industry. In the USA the break-even prices for UOG are of the order of $5 per MMBtu for gas and $60 per barrel of oil. The entire US UOG industry is running at a loss, with the gas price at around $3 and the oil price at $50. Historically, the raw sale value of UOG gas (around $200 billion) has been less than half the production cost. The gap has been financed by debt in the form of junk bonds that are now worthless.

Estimates of UK shale gas costs vary from $6 to $13 per MMBtu. Over-optimistic projections of possible UK UOG production rely on unrealistically long lifespans for wells and on an assumed total volume of gas produced which is over double that of actual US values. Well production peters out after 5-8 years, and the estimated ultimate recovery (EUR) is more like 1.4 billion cubic feet (bcf) per well, not the 3.2 bcf assumed by KPMG. The time taken to drill multi-well pads and the capital cost of the equipment required both mean that a UK, still less a Scottish, UOG industry can never be realised. Redundant US equipment cannot be mobilised for UK use because the vehicles are not homologated for European roads.

Regulation, split between four agencies, is currently not up to the task, as I demonstrate with numerous examples. It relies far too much on self-reporting. The nascent UK UOG industry to date is dominated by small-time cowboy operators whose technical shortcomings are legion. The financial soundness of some of them has been questioned. However, they feel they have practically *carte blanche* to ignore or modify retrospectively the imposed planning conditions, boosted by the support of the current Westminster government. No bonds are required to cover the costs of possible future pollution and restoration. The promises of community support are empty because the companies will never make a profit.

Industry influence is insidious, and present even in the SG-commissioned reports. There is no need for even limited licensing for 'test' fracking, since we already know enough about the geological structure of the shale basins and the properties of the shales themselves. We should instead learn from other jurisdictions such as France, Germany, Bulgaria and New York State, all of which have either banned UOG outright or else have instituted an extended moratorium.

Lastly I present evidence from several academic research groups, including my own *alma mater* the University of Glasgow, which demonstrates the hidden hand of the UOG industry in trying to skew the fracking debate in its favour amongst academics, and to silence dissenters. The views of certain academics should therefore be treated with the greatest caution. Fortunately, not all UOG research groups and individuals have succumbed to industry influence in this way.

I recommend that the current moratorium on UOG be converted into a permanent ban.

However, in the event that the SG decides in favour of resuming UOG, I present a list of recommendations that should be put in place before any such activity recommences.

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1 INTRODUCTION

1.1 Relevant personal details from my CV

I am Emeritus Professor of Geophysics in the University of Glasgow. I have no current link with any research group at the University, nor would I wish to. Although I am now a French resident I remain a British citizen, and take an active interest in UK, French and foreign affairs, as well as in various facets of scientific research.

Prior to my taking up the Chair of Geophysics at the University of Glasgow in 1988 I was employed by the British Geological Survey (BGS) in Edinburgh, from 1973 to 1987. I was a research scientist, rising to the post of Principal Scientific Officer. My work in the BGS from 1973 to 1986 was funded by the UK Department of Energy as part of a Commissioned Research programme on the geology of the offshore UK region. I also gave geological advice to the Foreign & Commonwealth Office on matters pertaining to UK territorial claims offshore. This was during the exciting phase of early discoveries and development of the North Sea. I headed a team of seismic interpreters working mainly on the prospectivity of the western margins of the UK, using the industry seismic and well data supplied to the Department of Energy. As a result I became the UK's leading expert on the deep geology of the continental margin west of the British Isles. Although our interpretation groups in the BGS were never able to commission our own wildcat wells, we had many 'virtual successes', where our independent interpretations were confirmed by subsequent drilling, and where the industry operator was proved spectacularly off-course.

In the 1990s I was closely involved in the search for a UK underground nuclear waste repository. I served on the BNFL Geological Review Panel from 1990 to 1991. I served on this panel to support BNFL's case for a Sellafield site for a Potential Repository Zone (PRZ), at the time when Nirex was investigating both Dounreay and Sellafield. I resigned from the panel after the case for Sellafield had been successfully made.

I was closely involved with Nirex at this epoch, and conducted for Nirex an experimental 3D seismic reflection survey, which took place in 1994. The survey encompassed the volume of the proposed rock characterisation facility (RCF) – a deep underground laboratory planned as a precursor to actual waste disposal. This was a double world 'first' – the first ever 3D seismic survey of such a site, and the first academic group to use this method, which at the time was just emerging as an essential tool of the oil exploration industry.

Since my retirement from the university in 1998 I have carried out private research, acted as a consultant to the oil industry, and maintained an interest in the geological problems raised by nuclear waste disposal, shale gas exploration and coal-bed methane exploration.

1.2 Declaration of interest

I declare no conflict of interest. I acted as a consultant to the Government of India and several small oil companies during the period 2001-2010, investigating conventional fossil fuel exploration. I ceased such consulting work in 2011.

For the avoidance of doubt, I have more recently been paid small honoraria in return for providing evidence on behalf of groups opposing planning applications for specific projects. The sum total of these emoluments has been of the order of £3000 over the last five years, which does not even cover my research expenses.

I have no pecuniary interest in the outcome of the consultation. I have no immediate family members resident in Scotland, nor do I possess any property there. My submission is made *pro bono publico*.

1.3 Approach to the consultation

I am writing from a largely British perspective, on the assumption that current legislation is mostly UK-wide, and that only some powers, such as licensing under the OIl and Gas Authority, will be devolved to Scotland. Therefore I am assuming, for example, that the guidance on mineral extraction does and will continue to apply to Scotland, and that projects such as UOG will be classed as national infrastructure.

I am not responding directly to the ten questions posed in the Talking "Fracking" consultation paper, but my responses to some of these questions will be found under the following sections:

Q1: What are your views on the potential social, community and health impacts of an unconventional oil and gas industry in Scotland? I leave the deleterious public health, social and atmospheric pollution effects of the putative Scottish industry to other respondents, including Professor Andrew Watterson and Dr William Dinan of the University of Stirling. These two researchers have responded to the current consultation, a copy of which they have supplied me. I support wholeheartedly their expert views

Q2: What are your views on the community benefit schemes that could apply, were an unconventional oil and gas industry to be developed in Scotland? This question assumes that a profit will be made from UOG, which is very unlikely to be true (Section 6). Therefore it follows that there will be no so-called 'community benefits'.

Q3: What are your views on the potential impact of unconventional oil and gas industry on Scotland's economy and manufacturing sector?

Q4 What are your views on the potential role of unconventional oil and gas in Scotland's energy mix? I discuss UK national energy policy and ensuing legislation in Section 4.

Q5: What are your views on the potential environmental impacts of an unconventional oil and gas industry in Scotland? They are likely to be seriously harmful *via* atmospheric pollution in the short to medium term, and potentially gravely harmful to groundwater resources in the short to long term. The risks to groundwater are discussed in Section 5.

Q6: What are your views on the potential climate change impacts of unconventional oil and gas industry in Scotland? I am not commenting further on the anthropogenic global warming (AGW) implications of developing a whole new fossil fuel industry, other than to add my support to the views of others that it should not happen, based on the scientific evidence.

Q7: What are your views on the regulatory framework that would apply to an unconventional oil and gas industry in Scotland? Many case histories show that the current UK and Scottish regulation is not up to the task (Section 7). I recommend toughening of the regulation, in the event that UOG does start up, in Section 8.2.

Q8: Overall, and in light of the available evidence, what do you think would be the main benefits, if any, of an unconventional oil and gas industry in Scotland? This question is practically meaningless in the absence of a context, such as: benefits compared to what alternative courses of action? I discuss national energy independence - a potential benefit - in Section 4.

Q9: Overall, and in light of the available evidence, what do you think would be the main risks or challenges, if any, of an unconventional oil and gas industry in Scotland? It is highly unlikely to be profitable unless current oil and gas prices double or triple from their current levels. The environmental risks will be almost impossible to overcome, particularly because the zone of most economic interest is also the place where most of Scotland's population lives.

Q10: If you have any other comments on the issues discussed in this consultation, please provide them here. See the main body of my submission.

2 DEFINITION OF UNCONVENTIONAL HYDROCARBON RESOURCES

2.1 National planning practice guidance

The Minerals section of Planning Practice Guidance, published on 17 October 2014, states:

> "*Conventional hydrocarbons are oil and gas where the reservoir is sandstone or limestone. Unconventional hydrocarbons refers to oil and gas which comes from sources such as shale or coal seams which act as the reservoirs.*"

This attempt to define the difference between conventional and unconventional hydrocarbons conflates the mineral itself ("*hydrocarbons*") with the process ("*comes from*") and the supposed source or reservoir rock. But the difference between the two terms is fundamentally one of resource extraction method; the rock type is irrelevant, apart from coal bed methane, in which coal is evidently the source. The guidance fails to recognise this point.

The definition is unsound for the following reasons:

> 1. It uses overly-simplistic rock types to differentiate between the two resources - "*sandstone*", "*limestone*", "*shale*", "*coal seams*" - without defining them properly. Such nomenclature is too black and white; in practice, there are gradations between end-member rock types; for example, geologists can describe a muddy sandstone, a sandy limestone, or a sand-prone shale. The end-members themselves, for example, 100% pure limestone, are rather rare in nature.
>
> 2. There is no mention of the geological context within which any of these rock types occur, for example, basin position, trap geometry, layer thickness, etc., nor the source where the hydrocarbons have been generated.

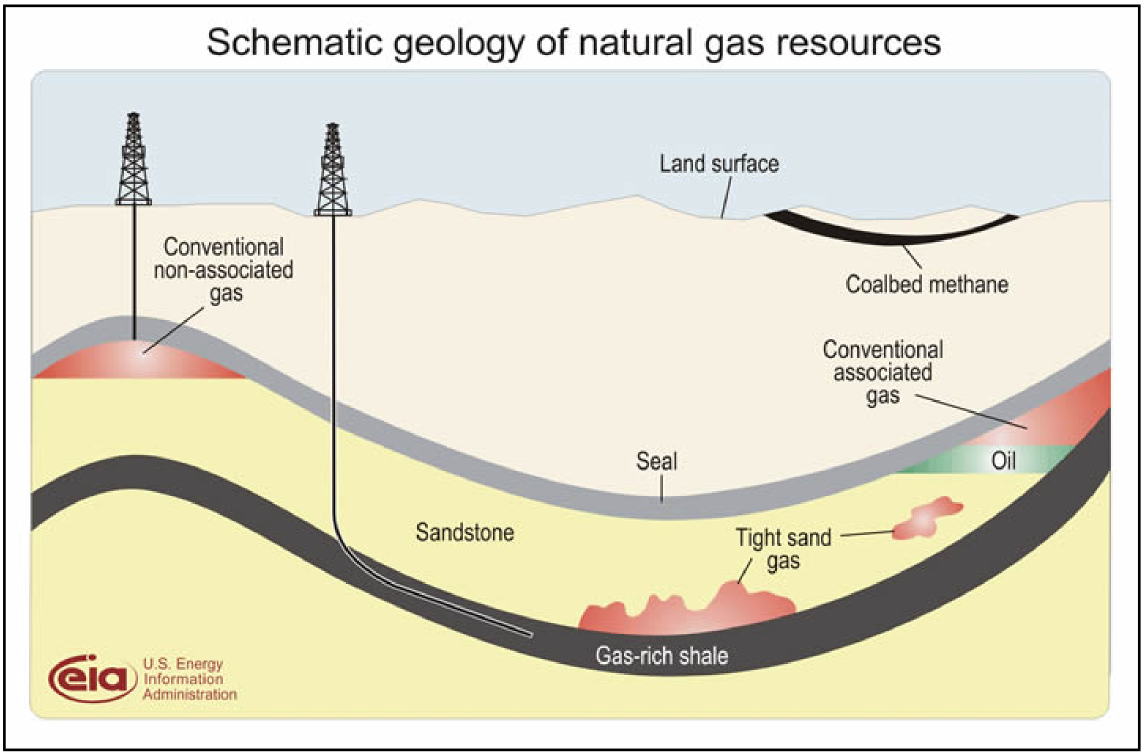

Figure 2.1 Schematic geology of gas resources, from US Energy Information Administration.

3. There is no mention of the physical properties of the rock types, such as permeability and porosity.

4. It omits mention of the physical and chemical properties of the "*hydrocarbons*" themselves, e.g. viscosity, API gravity (oil), or alkane (gas).

5. It omits to mention the processes by which the hydrocarbon is extracted, in particular the difference between hydrocarbons which are extracted from the rock with little or no treatment, *versus* those requiring extensive treatment to make them flow - e.g. steam heating, acidising, or hydraulic fracturing, or whatever forms of reservoir stimulation.

6. There is no mention of the economic aspects of the production process.

I wrote to the Department of Communities and Local Government on 9 March 2017 asking for the information to justify its definition, but was fobbed of by a set of irrelevant links. The request for an internal review produced a response that goes round in circles. I am currently complaining to the Information Commissioner.

The SG consultation paper defines conventional oil and gas as "*Oil and gas that is recovered by drilling a well in porous rock, with the oil or gas flowing out under its own pressure.*" Coal bed methane "*is considered to be an unconventional source of gas because the gas is absorbed in the coal rather than being held in pore spaces.*"

UOG is defined in the KPMG report of October 2016, commissioned for this consultation, as follows (section 2.2.1):

"The term 'unconventional' in UOG refers to the types of geology in which the oil and natural gas are found. For the purpose of this study, UOG includes shale gas, associated liquids and coal bed methane.

Shale gas is natural gas coming from unconventional sources, i.e. it is found within organic-rich shale beds, which are layers of low permeability rock rather than a conventional 'reservoir' capped by shale or other beds (White, Fell, & Smith, 2016). Similarly, shale oil is oil obtained from bituminous shale, while coal bed methane is a form of natural gas extracted from coal seams. "

The KPMG report cites White, E., Fell, M., & Smith, L. (2016), which is a House of Commons briefing paper no. 6073 'Shale gas and fracking'. The online version is now dated 13 April 2017, authored by Delebarre, Ares and Smith. This briefing paper, in its latest version at any rate, has a note on the definition of UOG, but in imprecise terms:

"The conventional view was that oil and gas would mature within these organic-rich and low-permeability rocks, and then migrate into conventional reservoirs from where they could be recovered. However, with advances in drilling and wellsite technology, and increases in the wholesale prices of hydrocarbons, production of gas directly from the shale beds is now commercially viable. The processes are described below."

These definitions are an improvement upon the Planning Guidance efforts discussed above, but are still incomplete. This is surprising, given that this is the subject of the consultation. It is therefore imperative to develop a scientific and evidence-based definition.

2.2 Scientific definitions

There is no universally agreed definition of the difference between conventional and unconventional hydrocarbon mineral extraction; various versions in the scientific and technical literature (summarised in Appendix 1) emphasize different aspects mentioned in points 1-6 above. However, all reasonable definitions that I am aware of include, either implicitly or explicitly, the permeability of the host rock.

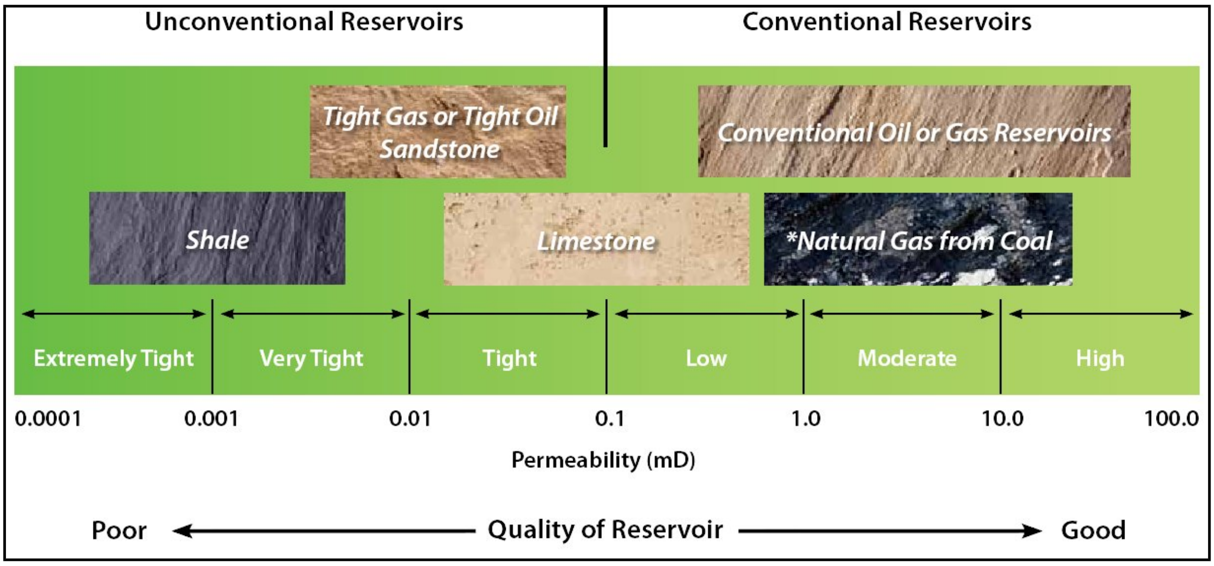

Figure 2.2 Spectrum of permeabilities to differentiate between unconventional and conventional reservoirs (Canadian Society for Unconventional Resources).

The figure of 0.1 mD (milliDarcies) for the host rock is generally agreed to differentiate between the two extraction procedures, although the Society for Petroleum and Coal Science and Technology of Germany defines a higher value of 0.6 mD. Given the vast range of possible permeabilities and the limited precision in estimating permeability, the scale is usually presented in logarithmic form, so that units (decades) on the scale are 0.001, 0.01, 0.1, 1, 10 ... mD and so on. Below 0.1 mD the process required to extract the hydrocarbons is unconventional, whereas above that value it is considered to be conventional.

Next in importance to a quantitative definition using permeability comes the geological setting in which the hydrocarbon-bearing rock occurs. Thus conventional resources are found in finite and well-defined traps, whereas unconventional gas or oil is distributed throughout a widespread layer with no clear-cut boundaries.

Along with the two criteria above, the process of extracting the hydrocarbons is important. It is variously described as fracking, acidising, massive stimulation, additional extraction or conversion technology, or assertive recovery solution. Although different in detail, what they all have in common is the aim of making the hydrocarbon flow when it would otherwise not do so.

2.3 Discussion and conclusion

No definitions of which I am aware (see Appendix 1) regard so-called "*sandstone*" or "*limestone*" reservoirs as automatically conventional, as simplistically defined by the 2014 Planning Guidance. On the contrary, many sandstone and limestone reservoirs are called 'tight', meaning that unconventional extraction methods are required.

Given the unscientific and imprecise nature of the Planning Guidance definition, the SG should ignore it as being unsound. An unconventional hydrocarbon resource can be defined as having one or more of the following criteria:

- Host rock permeability of <0.1 mD.
- Diffuse or non-defined distribution, in contrast to a conventional trap.
- Requires stimulation to make the fluid flow.

3 DEFINITION OF HYDRAULIC FRACTURING

3.1 Introduction

The SG paper defines hydraulic fracturing in the glossary as "*A drilling technique, commonly referred to as 'fracking', that fractures rock to release the oil and gas contained in the rocks.*" It goes on to amplify the meaning, as follows:

> "*Hydraulic fracturing (or 'fracking') is a drilling technique that is used to fracture rock to release the oil and gas contained in those rocks. It is most commonly used to extract oil and gas from shale. The rock is fractured by injecting pressurised fluids into the rock to prise open small spaces in the rocks, which release the oil or gas. Hydraulic fracturing is used extensively in North America for extracting oil and gas from shale reserves. By 2015, the number of hydraulically fractured wells in the United States reached 300,000*[1]*. Hydraulic fracturing is also used by other industries, as outlined in Box 1.*"

The superscript reference is U.S. Energy Information Administration, Oil Production in the United States 2000-2015.

The House of Commons briefing paper no. 6073 'Shale gas and fracking', cited in the KPMG report, discusses the Infrastructure Act, but nowhere makes an explicit definition of fracking.

These definitions are fine as far as they go, but we need to be clearer about what fracking means in the context of unconventional oil and gas extraction from shale. We should refer in this instance to *high volume hydraulic fracturing* (HVHF) or *super-fracking* (Turcotte *et al.* 2014). The implication of the phrase HVHF is that high volumes of water are used, in contrast with other applications of fracking such as stimulation of vertical wells, water wells or geothermal boreholes. The UK government has chosen a definition of the volume in HVHF which is designed to make it easier for oil companies to hide behind a misleading definition.

3.2 The UK government definition of shale fracking

Section 50, supplementary para. 4B to Section 4A of the Infrastructure Act 2015 defines hydraulic fracturing ('fracking'), as follows:

"Section 4A: supplementary provision

> *(1) "Associated hydraulic fracturing" means hydraulic fracturing of shale or strata encased in shale which—*
>
> *(a) is carried out in connection with the use of the relevant well to search or bore for or get petroleum, and*
>
> *(b) involves, or is expected to involve, the injection of—*
>
> > *(i) more than 1,000 cubic metres of fluid at each stage, or expected stage, of the hydraulic fracturing, or*
> >
> > *(ii) more than 10,000 cubic metres of fluid in total."*

There are two intrinsic weaknesses in the wording of this definition:

Weakness 1: "*shale or strata encased in shale*", and

Weakness 2: the word "*expected*" (quoted twice).

The first weakness is that the phrase in question is almost meaningless. Does it mean that the strata referred to which are not composed of shale, have to lie in direct contact with shale, above, below and all round on all sides? The phrase is unclear. In practice, almost any layer within a sedimentary basin is likely to be 'encased in' shale, excluding the very bottom layer resting on 'basement' rock, and excluding the uppermost layer at the surface of the earth. This is because shale is a very common variety of sedimentary rock, and there are likely to exist layers of shale above and below the stratum in question.

The second weakness, the expectation of a specified threshold volume of fluid, implies a belief that a certain amount will or will not be used. 'Expectation' is not being used in the statistical sense of the word, because the definition refers to discrete operations, occurring one at a time, and not to an aggregate of simultaneous and unpredictable operations for which statistical methods might be appropriate. The questions arise; who is doing the 'believing'?

What happens if the expectation that less than the specified amount turns out to be incorrect? The process of hydraulic fracturing involves the insertion of fluid into rock at depth. The volume being inserted is both continuously monitored and controlled by the operator at the surface. Now it may be the case during any one fracking stage, for which planning approval has been granted on the basis that the process will *not* fall under the definition of associated hydraulic fracturing of shale, that the operator may decide, based upon the perceived progress of the fluid pressure and volume, to insert a greater volume than specified by the threshold. That action implies that the planning consent has been wilfully breached. The alternative, which is under the complete control of the operator, is merely to turn off the fluid supply valve before the threshold is exceeded. This freedom of action applies both for any one stage and for the *n*'th stage at which the total threshold is in danger of being breached.

In conclusion, I can see no justification for someone's belief to be inserted here as part of a legal definition. It implies a discretion on the part of the operator, of whether or not to abide by the planning consent. Such a weak phrasing of the definition may therefore be open to challenge.

3.3 The use of fluid volume as a criterion

The definition involves the specification of two alternative minimum fluid volume measures, without qualification. It follows the definition of the European Commission (EC) published in the Official Journal of the European Union dated 8 February 2014. This in turn seems to be based on a consultant's report to the EC by AEA dated August 2012, proposing a figure of 1000 cubic metres for each fracking stage. There is little justification in this report for such a figure, and in any case the scanty research upon which it is based, comprising merely a literature review, has been superseded by the thorough US Geological Survey (USGS) continent-wide study discussed below.

Two questions arise from this definition; (a) whether fracking can be soundly defined by such a criterion, and (b) even if this be the case, whether the quoted threshold values are based on sound evidence.

Dr Stuart Gilfillan and Professor Stuart Haszeldine, shale gas researchers at the University of Edinburgh, raised both these questions in an article published in April

2016. They quoted an extensive data compilation from the US Geological Survey (USGS) involving over a quarter of a million fracked oil and gas wells. Because the wells have been fracked, they are, using any reasonable definitions (discussed in section 2 above), unconventional.

3.4 The USGS definition of HVHF

The USGS data are treated statistically, with yearly or other medians being calculated. The type of well falls into three categories; vertical (V), directional (D) or horizontal (H). There are two UOG types distinguished - oil (O) or gas (G). The yearly medians for the six resulting categories, estimated from 2000 to 2014 inclusive (15 years in total, but the data being incomplete for 2015), show a very pronounced bimodal distribution, separating horizontal wells H with large water volume use from directional D or vertical wells V with lesser water volume use (Figure 3.1). The authors argue on geographical grounds that the horizontal wells, by and large, represent shale plays rather than tight sandstone or limestone plays. This is demonstrated by the map in Figure 3.1.

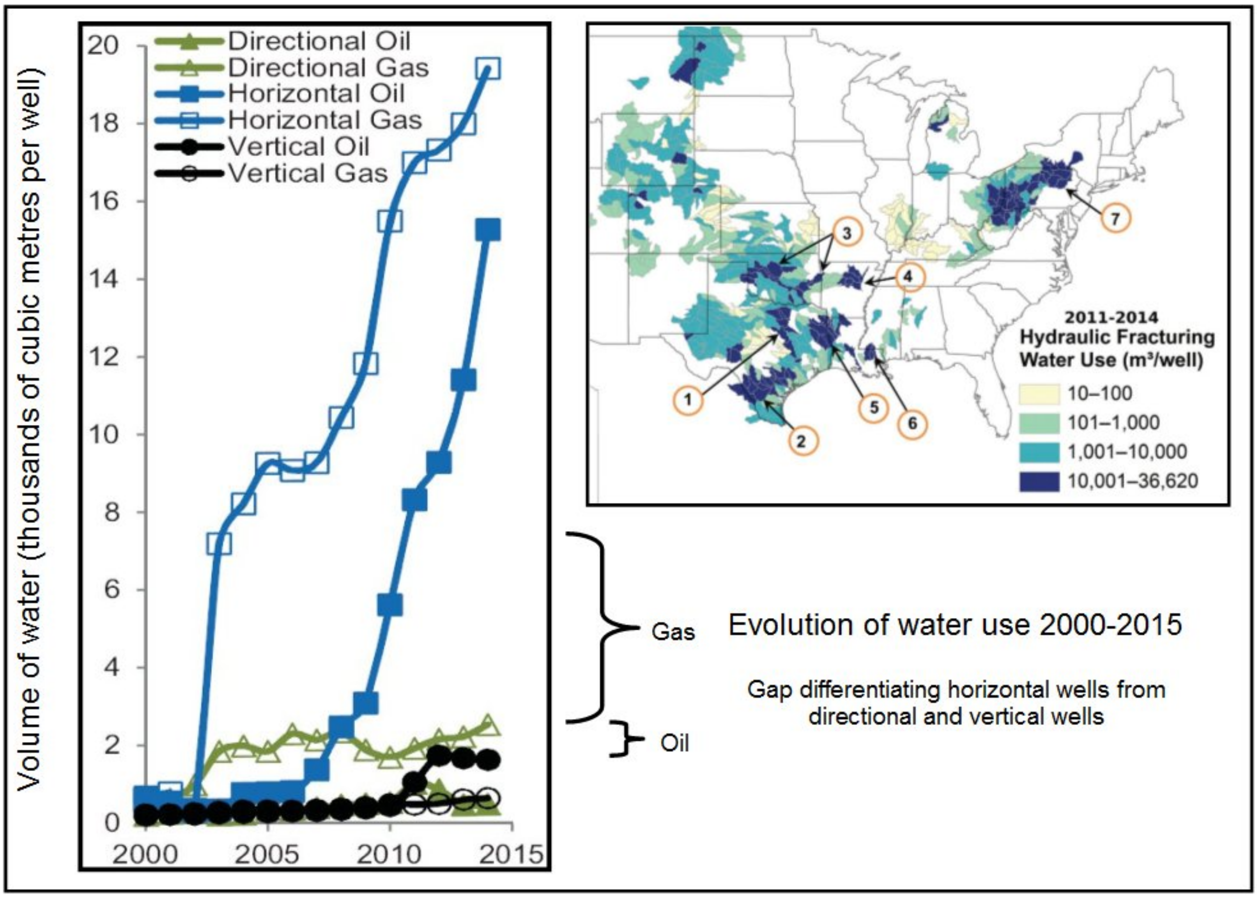

Figure 3.1. US study of 264,000 fracked wells. Graph shows the range of values which differentiate between horizontal wells (high volume usage) and deviated or vertical wells (low volume usage), for oil and for gas separately. Shale gas plays are numbered in the map: (1) Barnett, (2) Eagle Ford, (3) Woodford, (4) Fayetteville, (5) Haynesville-Bossier, (6) Tuscaloosa, and (7) Marcellus and Utica. Diagram from Gallegos et al. 2015 with additions.

For simplicity in the following summary the directional and the vertical categories are grouped together as DV.

H wells of both resource types show an annual evolution towards greater and greater water use, up to and including 2015. DV wells reveal a slight growth in water use, but flattening out over time.

For gas wells, the annual median values of water volume (in cubic metres per well) that separate horizontal H from deviated/vertical DV wells are as follows:

DV ≤ 2537, in 2015; H ≥ 7192, in 2003.

(≤ means 'less than or equal to; ≥ means 'greater than or equal to').

In other words, any value between 2500 and 7000 cubic metres could serve as the threshold criterion for differentiating between H shale well water volume use and other tight rock, drilled by DV wells.

For oil wells the separating figures are:

DV ≤ 1740, in 2012; H ≥ 2479, in 2008.

So a round figure of 2000 cubic metres could be used as the threshold figure.

The figures quoted here are medians for water use per well. The secular increase in water use in horizontal wells is ascribed to evolving drilling and fracking techniques; for example, wells are generally much longer now than a decade ago. There are significant differences in the mean water use between shale plays, reflecting, in part, different physical properties of the shale.

3.5 Conclusions on the definition of HVHF

The results suggest firstly that the figure of 10,000 cubic metres chosen in the Infrastructure Act definition is too large by a factor of four. Secondly, the utility of having such a definition in the first place could be considered unsound. As the USGS authors conclude:

> *"Because hydraulic fracturing is not a one-size-fits-all operation, assumptions and generalizations regarding water use in hydraulic fracturing operations and the potential for environmental impacts should be made with caution."*

The Edinburgh researchers suggest that strain rate may prove to be a better criterion than simply fluid volume; this is a measure of how fast the rock cracks up when fracked, and involves the applied fluid pressure and the rate of flow, as well as the total volume. But they question why such a definition is needed at all.

I therefore submit that the attempt to define hydraulic fracturing by any minimum threshold volume criterion is unsound. In addition, the UK volume figures selected as discrimination criteria are contrary to established evidence, by being far too high, and the wording of the definition itself has weaknesses which render it legally unsound.

Fracking remains fracking if it artificially enhances permeability in rock, whether the method used is (a) fluid under high pressure or (b) dissolution by acids. Fracking type (a) is hydraulic fracturing; fracking type (b) is chemical fracturing. Both types of permeability enhancement fall under the umbrella of 'unconventional' fossil fuel exploitation.

4 NATIONAL POLICY ON ENERGY INDEPENDENCE

4.1 Introduction

Local authorities throughout the UK are obliged to draw up a Minerals Local Plan. Comments or representations on a Minerals Local Plan being prepared by the local minerals authority and put out for consultation should adhere the following guidelines (this text comes from West Sussex County Council, but other local authorites have similar guidelines):

> *"3. Soundness*
> *If it is the actual content of the Plan which you wish to comment on or object to, it is likely that your comments or objections will relate to soundness. To be sound, the Plan should be:*
> *...*
> *3.2 Justified*
> *This means that the Plan should be based on a robust and credible evidence base involving:*
> *...*
> *• Research/fact finding: the choices made in the plan are backed up by facts.*
> *...*
> *3.4 Consistent with National Policy*
> *As well as being a matter of legal compliance, the Plan's consistency with national policy is also a matter of soundness (relevant national policy is explained in section 2.2 of the Plan). Where there is a departure from national policy, the Authorities must justify this approach.*
> *If you feel the Authorities should depart from national policy in order to meet a clearly identified and fully justified local need, then please explain why and support this with evidence."*

I explain below why certain aspects of national policy are not based on a credible research base or finding of facts. It therefore follows that a MLP, in following these policies, is similarly not based on a credible research base or finding of facts. A MLP is therefore justified in deviating from national policy, in order that it may be be founded upon a credible research base and finding of facts.

In respect of national policy, both the Guidance Notes and the Minerals Background Paper refer to the 2007 white paper '*Meeting the energy challenge*'. I submit that reliance on this white paper is unsound, regarding energy in general, and hydrocarbon development in particular, for the following reasons.

4.2 Unconventional oil and gas not mentioned

The exploitation of unconventional oil and gas (UOG) had barely begun (and in the USA only) by 2007, the date of the white paper. The words *unconventional, hydraulic, fracturing,* and *tight* (in the context of tight oil or gas) are not even mentioned in the white paper. Given that the white paper on energy evidently failed to foresee the rise (and fall) of the entire UOG industry, it should not be relied on a decade later for policy designed to extend from now to 2033. The history and economics of the US shale industry are discussed in detail in Section 6.

4.3 Carbon emissions

Anthropogenic global warming (AGW) has proceeded apace in the last decade. It is difficult to reconcile the continued burning of fossil fuels, either conventional or unconventional, with the UK's targets and obligations to reduce CO_2 emissions, given that they have not been offset, nor will they be offset in the foreseeable future, by carbon capture and storage (CCS) schemes and/or large-scale development of nuclear power.

4.4 Renewable low-carbon energy

The costs of renewable energy have come down considerably since 2007. The Department for Business, Energy and Industrial Strategy (BEIS) now accepts that large-scale onshore wind electricity generation schemes produce electricity at lower cost (£62/MWh) than even gas turbines (£66/MWh), formerly considered the cheapest form of electricity generation.

The 2007 white paper recognised the danger of inaction on anthropogenic global warming (AGW; citing Lord Stern's report of the previous year), and the need for carbon emissions reductions via, *inter alia*, carbon capture and storage (CSS) to offset the burning of fossil fuels. The paper promoted nuclear energy as "one of the currently more cost effective low carbon options". But whereas Lord Stern's warning is ever more true a decade on, the white paper's optimism about CSS helping to offset CO_2 emissions, and the supposed cost-effectiveness of nuclear power, have both proved to be misplaced.

4.5 Gas imports

Security of supply of was quoted in the 2007 white paper as being of concern, but only UK offshore supplies and onshore storage were discussed. The paper stated that *"Oil and gas supplies are concentrated in regions which include less stable parts of the world"*. This may remain true of oil, but is no longer the case for gas. Nevertheless, security of supply is now mentioned as a reason for developing an indigenous UK UOG industry, with Russia being cited as the major risk.

Figure 4.1 comes from the Task Force on Shale Gas fourth report ' The Economic Impacts of a UK Shale Gas Industry' published in December 2015. It demonstrates that over 70% of imports are from safe and reliable European countries, Norway and the Netherlands. Norway's gas is indigenous, but some of the Dutch gas imported to the UK is of Russian origin. The addition of liquid natural gas (LNG) from Qatar raises the percentage to 97%. Since then, the USA has entered the arena, with LNG arriving at Grangemouth.

None of the aforementioned countries can in any way be cited as politically or economically unreliable, apart from the possibility of Russia deciding to cut its exports to Europe. A research paper dated September 2016 about Russian gas policy from the Clingendael International Energy Programme, a Dutch-based research consortium of Dutch ministries and fossil fuel companies, concludes:

> "*As concluded by other papers of this series, prospects for additional LNG imports are more solid than those for new pipeline supplies from the Caspian or the Middle East. The availability of LNG for Europe however hinges on global market conditions.*

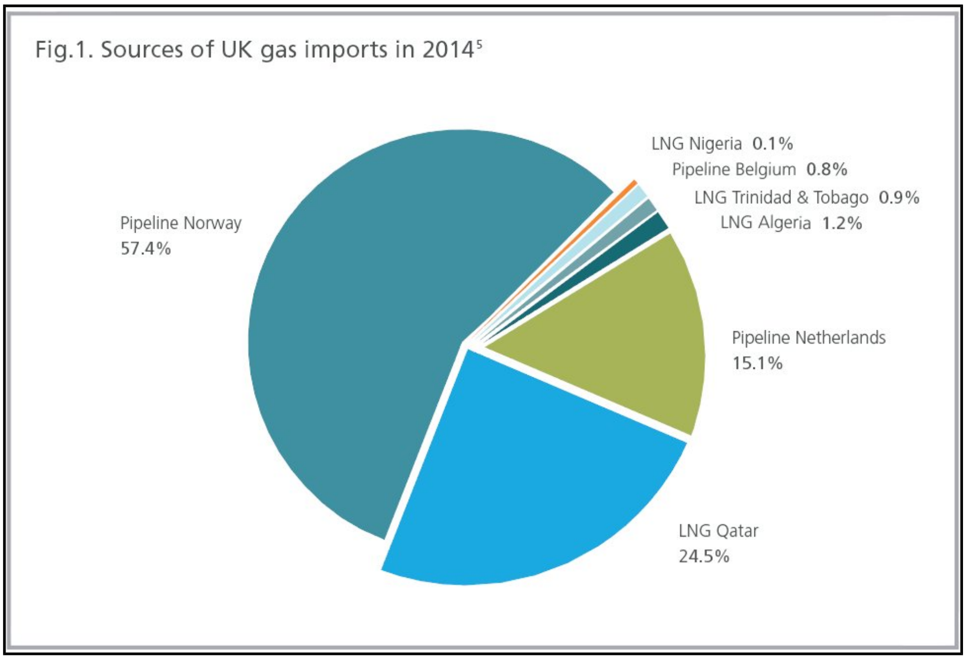

Figure 4.1. Sources of UK gas imports, 2014. The source of the Norwegian supply is indigenous. Much of the Dutch slice comprises Russian gas. Liquid natural gas (LNG) imports from Qatar account for a quarter of the imports.

> *As argued throughout the paper, a more likely scenario is one in which: a.) imports of gas from Russia will increase in absolute terms, driven by the EU's rising import needs and the competitiveness of Russian gas but b.) Russia's market share will remain somewhat constant around 30%, given political opposition in the EU to a further substantial growth in it.*"

Therefore the problem of foreign dependence on UK gas supply future, during the period over the next 10-20 years in which UK households will have the time to switch to other forms of heating, does not really exist. The supposed problem has been created by the UOG lobbyists.

4.6 Discussion

Planning practice guidance for onshore oil and gas (July 2013), quoted in the MLP guidance notes at para. 3.187 states that:

> *"Unconventional hydrocarbons are emerging as a form of energy supply, and there is a pressing need to establish – through exploratory drilling - whether or not there are sUOGicient recoverable quantities of unconventional hydrocarbons present to facilitate economically viable full scale production."*

This two-part assertion is unfounded: on the contrary: the only pressing need in energy supply is to promote and establish low-carbon forms of fuel, while simultaneously decarbonising the UK economy by the development of carbon capture and storage (CCS). The pressing need for CCS was cogently made by the parliamentary advisory group on CCS last year (the Oxburgh report to BEIS of September 2016).

It is untrue that unconventional hydrocarbons are an "*emerging*" form of energy supply; on the contrary, they are a declining and slowly dying form of energy supply, as I argue below, and there is no rational or economic need - pressing or otherwise - for the UK to encourage or advance such a form of continued reliance on fossil fuels.

National planning policy guidance states that:

> "*Hydrocarbons remain an important part of the UK's energy mix whilst the country transitions to low carbon energy supplies.*"

This argument is valid, although trite and self-evident; it is indeed impracticable for the 23 million UK households that depend on gas central heating, or for the vast majority of UK motor traffic, to abruptly cease using oil and gas. But the gradual weaning off from fossil fuels required, perhaps over two decades, is not a valid justification for encouraging or even permitting the growth of a new form of expensive and polluting form of fossil fuel energy - unconventionals. The timescale for such a putative development is in any case far too long, and the financial investments and risks are too great. This is discussed in more detail in Section 6.

In conclusion, the energy landscape has changed so radically since 2007 that little or no reliance should be placed on the 2007 white paper for either national or local policy. Therefore any MLP would be justified in ignoring that aspect of national policy. The economics and the required timescales are also against the development of an indigenous UOG industry.

5 ENVIRONMENTAL RISKS

5.1 Introduction

My concerns about the environmental risks of UOG focus on the risk of contamination of groundwater aquifers at or near the surface from the deeper extraction activities. In particular, I focus on the likelihood of geological faults acting as pathways for upward transmission of contaminated water and gases.

The risks of environmental contamination *via* faulty well construction and impairment has been established by US research and case histories. For example, a statistical study of some 41,000 wells in Pennsylvania by Ingraffea et al (2014) at Cornell University showed that methane migration via well leaks was much more likely with UOG wells, as compared to conventional wells.

All but a handful of the US case histories available in the public domain concern such well casing and/or cement impairment; the very small minority of the remaining cases being possibly or partly due to transmission through the geology and *via* faults in particular. Professor Ingraffea and his Cornell colleague Robert Haworth had previously declared in a point-counterpoint discussion in *Nature* in 2011 that leakage directly upward from the fracture zone was "*highly unlikely*". The reason for our divergence of opinion on the importance of geological pathways is explained below.

Much of the discussion below is taken from an online review paper I published in January 2016. The paper was put online for open discussion by the journal. My paper instigated a number of hostile comments from pro-fracking researchers. Although I was able to answer all the criticisms, I subsequently withdrew the paper from the editorial process. The editor agreed with me that it ended up covering a too diverse range of topics which could not adequately be handled by one article. Nevertheless I include below, where necessary, critiques of some of the commentaries I received.

The discussion then summarises UK case histories of proposed or actual UOG drilling in which faulting has been implicated.

Lastly I discuss the problem of underground disposal of wastewaters; that is, *flowback* water coming back up during or just after the fracking process itself, and *produced water*, produced as a by-product of the oil or gas production.

5.2 Review of faulting in relation to fracking

A joint review of fracking for shale gas by two UK academic societies (Royal Society and Royal Academy of Engineering, 2012) failed to address the problem of through-penetrating faults in the UK shale basins. Much of the report concentrated on the risk of induced seismicity. The problem of pre-existing faults was barely discussed at all, even though it was introduced as a subject for concern by a submission to the expert committee by the Geological Society of London. Instead, the report accepted uncritically the conclusions of a Halliburton study (Fisher and Warpinski, 2012), as did Green et al. (2012) in their report on induced seismicity commissioned by the Department of Energy and Climate Change (DECC). The Halliburton study concluded that upward migration via the fracks (vertical fractures created in a fracked shale) is very limited, but did not take into account through-going pre-existing faults.

A BGS report from 2012 on the potential impact on groundwater by shale fracking succeeded in not mentioning the word 'fault' at all. The Scottish Government's independent expert scientific panel report of 2014 on UOG did briefly mention faults as potential pathways to "*sensitive receptors (water users, water features)*", but did not develop this theme. The Health Protection Scotland report Volume 1, however, shows a diagram of potential contamination pathways taken from a German study of 2014 commissioned by the German government. Their diagram is shown here in Figure 5.1.

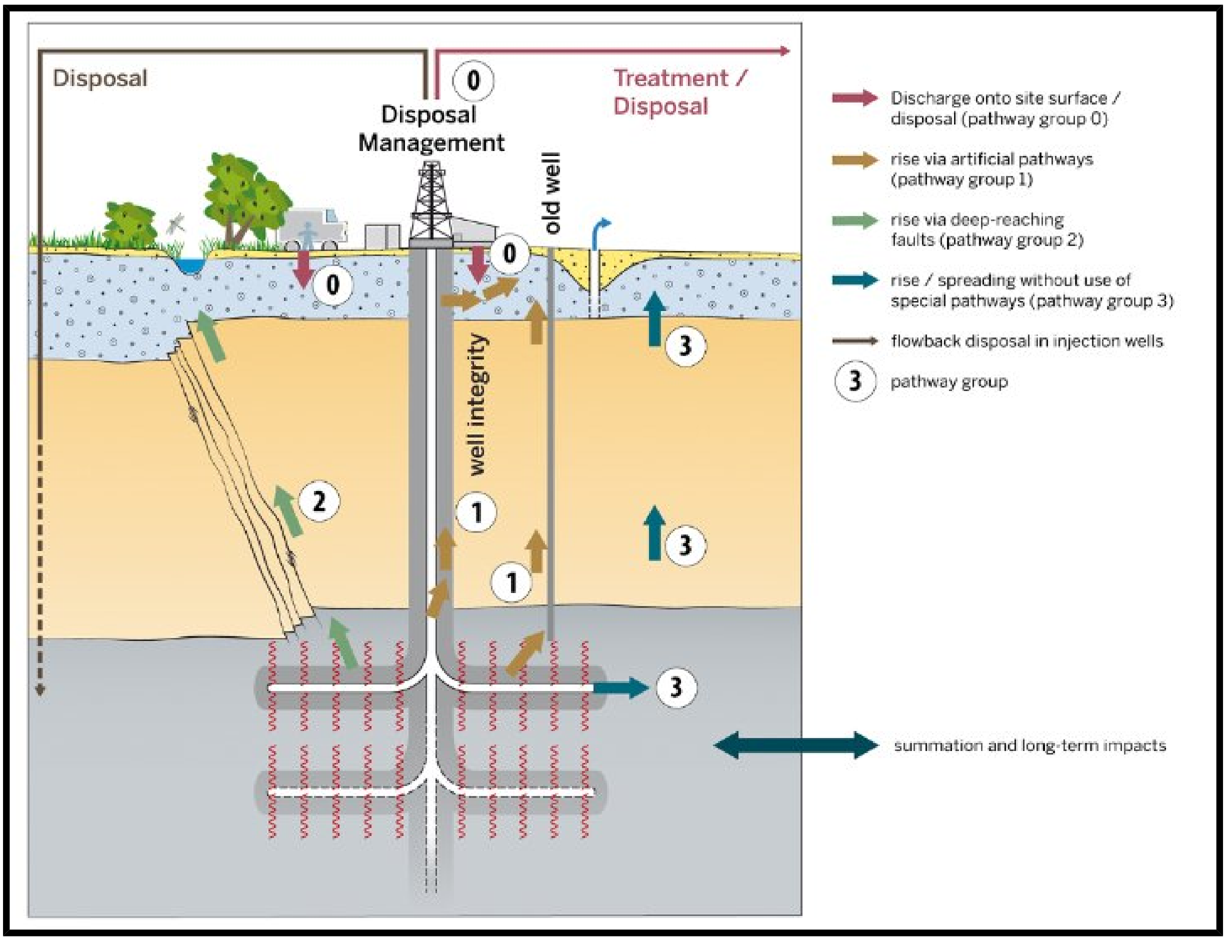

Figure 5.1. Potential water contamination pathways from Bergmann et al. 2014. Pathway 2 is via geological faults.

The sense of displacement of the layers by the fault in this diagram is different from what would be most common in the UK shale basins, but the principle is sound.

This collective myopia in the UK regarding faults as potential conduits is due to the fact that the US shale basins are very different from those in western Europe, but that the UK earth scientists considering the problem have not appreciated this fundamental difference. The UK shale basins are two to one hundred times smaller in area than their US counterparts, but hold a shale target two to one hundred times thicker. The US basins are mainly of *foreland or intracratonic* type, whereas the UK shale basins are *extensional*. The faulting in the US basins is generally deep and rarely reaches the surface, whereas the UK basins are pervaded by through-going faults.

My 2016 discussion paper reviewed the literature on faulting as potential pathways, linking the rapid development of the subject from its origins on 2009. I illustrated this with an organogram reproduced here as Figure 5.2. It is remiss of the geoscientists serving on the several review panels reviewing fracking that none of them seemed to be aware of this research field.

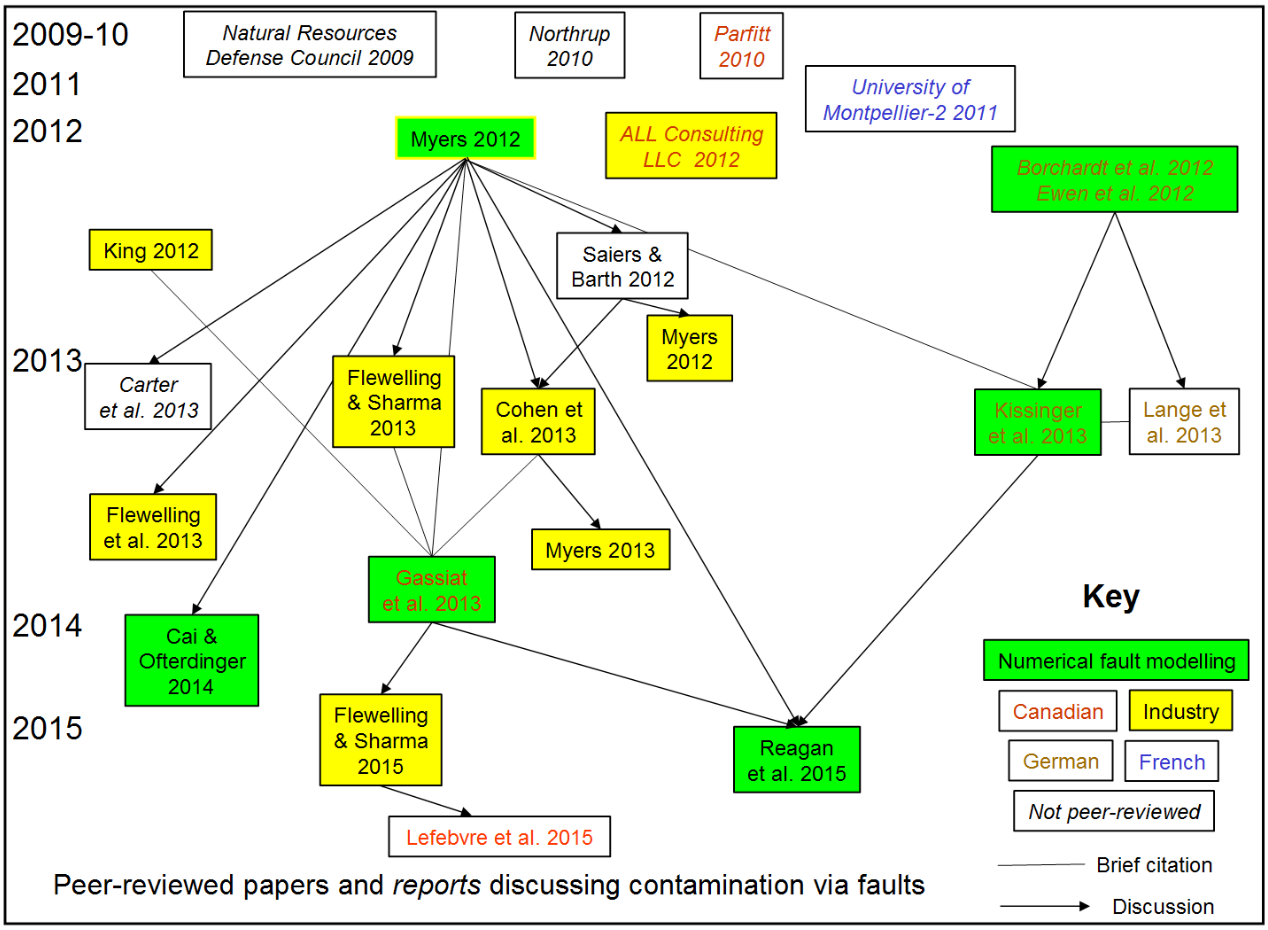

Figure 5.2. Organogram showing the develoment of the literature on faults as potential conduits for contamination from shale fracking (from Smythe 2016). A late-2015 numerical modelling paper not shown makes the total of such studies six.

Not only that, but one of these scientists, Professor Paul Younger of the University of Glasgow, a hydrogeologist, appears either to misunderstand the literature or to be unaware of it. I have explained in a non-technical blog article that he continues to assert that flow will be downwards along faults, whereas six quantitative research studies all agree about upward flow, even if they differ on the degree to which it happens.

I added a proposed supplement to my discussion paper, modifying and amplifying the evidence for fault-related contamination in a case history from Bradford County, Pennsylvania. The authors of the original case history had refrained from identifying an actual pathway from the Marcellus Shale to the polluted homeowner water wells; however, I did reach such a conclusion after demonstrating that the location of a horizontal fracking wellpath was less than 600 m from the fault zone previously identified, and that the sideways fracks from this wellbore could be practically contiguous with the fault. There is, furthermore, a statistically significant inverse correlation of level of methane pollution in the wells with distance away from the fault. The lesson from this US case study is that although through-going faults in the US are very rare, this is an example of demonstrable connection from the fracked shale to the surface.

I also mentioned in passing examples of deep groundwater circulation systems, one of which is in the Languedoc region near Montpellier. This is shown in Figure 5.1. Professor Paul Younger criticised me for including karst systems (hydrogeological systems in which limestone has pathways in it created by rainwater, which is slightly acidic). My rejoinder to him was that was that he had not read the cited works carefully enough, because the deep system descends 1000-1500 m below the limestones, through shales which were the target of fracking by Total, and back upwards to the surface along a fault, where where it is buffered by the main aquifer system (light blue ellipse in Figure 5.3). The evidence for the deep origin comprises various hydrogeochemical signatures.

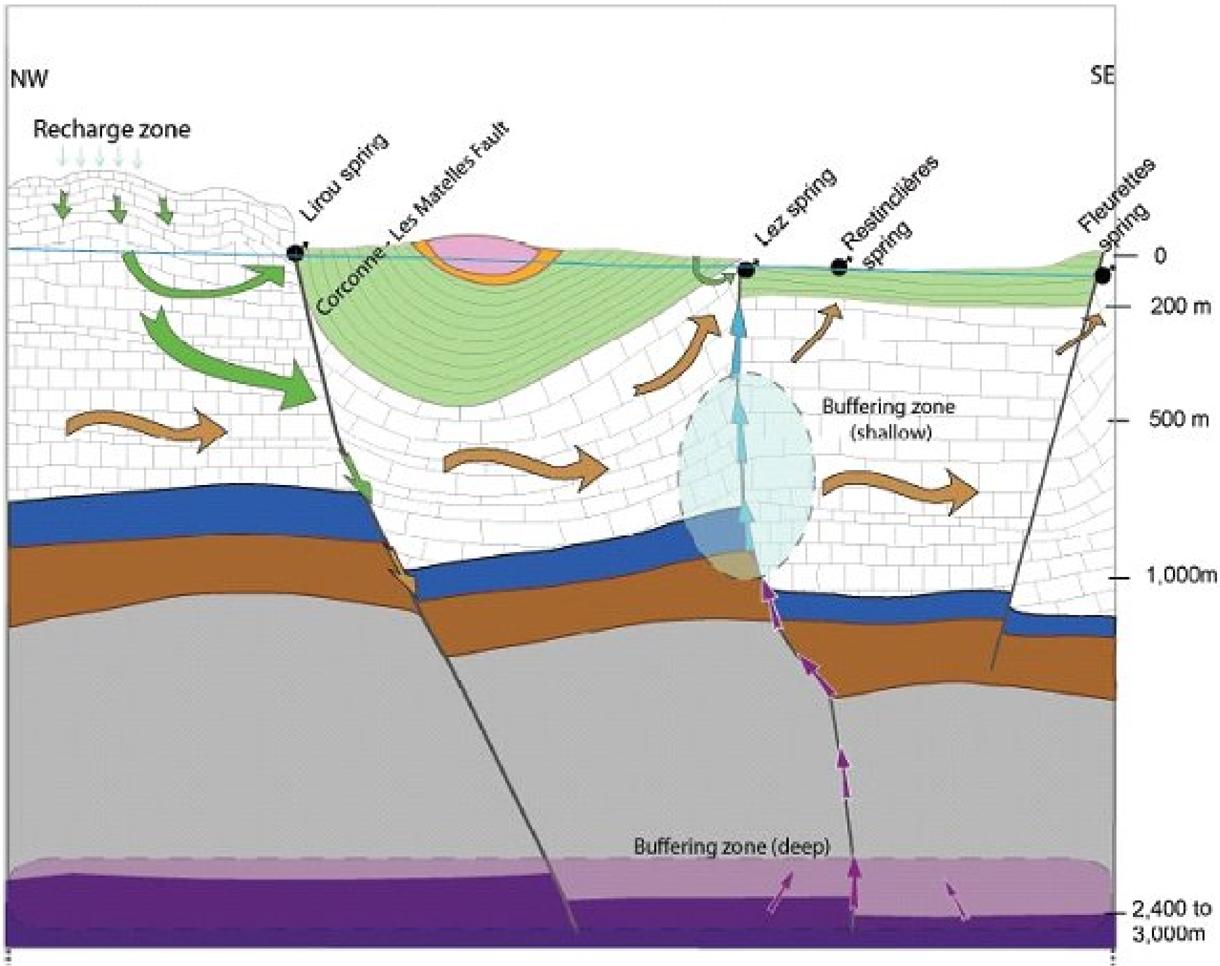

Figure 5.3. Cross-section showing the flow model from the karstified limestones in the Languedoc. The recharge zone and the white brick pattern are Jurassic limestones (light blue in Figure 1 above) of the main aquifer. Note the subsidiary system extending through the Toarcian shales (within the grey layer) down to 2400-3000 m depth, emerging at the Lez spring. Aquifer-confining rocks are: light green – Valanginian marls; orange and pink – Tertiary.

This example shows that faults can and do act as conduits, both at depth and through shale.

Dr James Verdon of Bristol University commented on my paper. He was unable to accept the conclusion, based on my unpublished work, that faulting is not a problem in the US shale basins. A logical scientific response would have been for him (and the other two commentators who made similar remarks) to provide some counter-examples, but he did not. Nevertheless, I am now publishing my results on this topic in the form of a web page atlas, with the aim of putting my negative results (i.e. almost no fault problem in the USA) into the public domain. At the time of writing this is work in progress.

5.3 UK case histories of faults in relation to UOG drilling

5.3.1 Dart Energy proposed CBM development at Airth

At the 2014 Planning Permission Appeal (the Falkirk CBM inquiry) Dart Energy represented the geology in a misleadingly oversimplified manner, for example in omitting major faults across the proposed development zone.

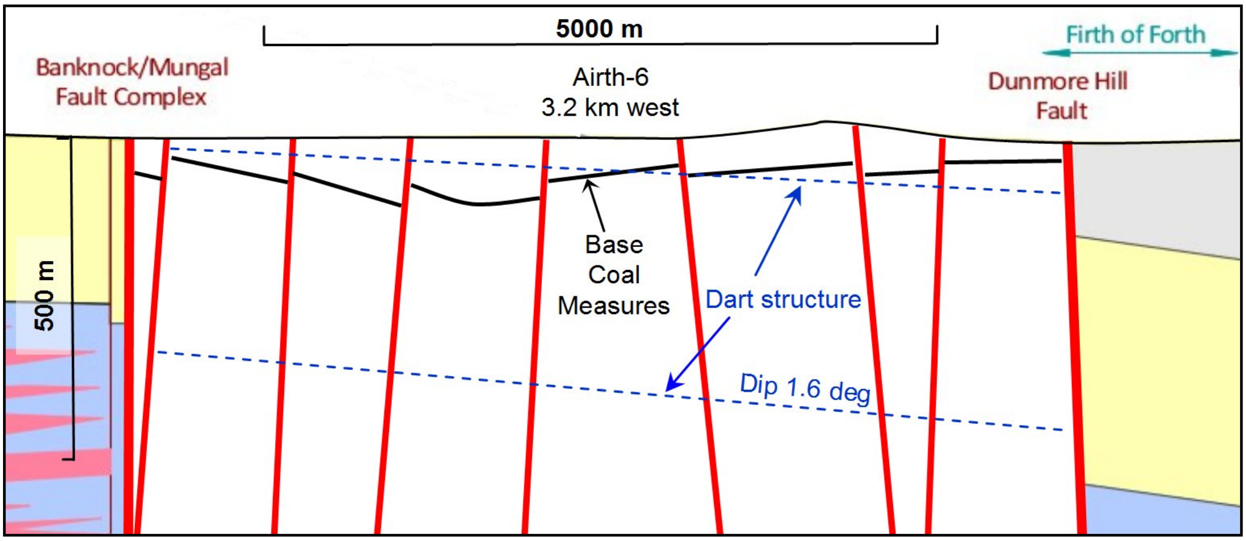

Figure 5.4. Schematic re-interpretation of the central part of Dart cross-section BB'. The section is aligned N-S with north on the left. The oversimplified Dart structure of a constant northward dip if about 1.6° has been replaced by a more accurate depiction of the structure of the base of the Coal Measures.

Figure 5.4 shows the Dart version of the geological layering (dotted blue lines), on which I superimposed the correct faulted geology. Seven important faults (red) were omitted by Dart. Dart's geological maps contained elementary errors. The closing submission by Sir Crispin Agnew QC for Concerned Communities of Falkirk (for whom I acted as an expert witness) noted that Mr Andrew Sloan, witness for Dart, admitted that the horizontal drilling could and did traverse faults. He went on to say that if the drillbit had lost contact with the coal seam after cutting through a fault, the procedure was to carry on drilling blind for up to one shift (12 hours). If the target (or another) coal seam had not been rediscovered by then the hole would be abandoned.

The Inquiry Reporters suspended their work after Mr Fergus Ewing, Minister for Business, Energy and Tourism, stated in the Scottish Parliament that there was to be a moratorium on granting consents for unconventional oil and gas developments in Scotland while further research and a public consultation was carried out. Therefore the outcome of the appeal is as yet unknown.

5.3.2 Cuadrilla at Balcombe, Sussex

In 2013 Cuadrilla drilled a new well Balcombe-2 on the site of the 1986 Conoco well Balcombe-1, and 10 m distant from it. I showed in August 2013 that Cuadrilla would probably drill through a nearby fault at shallow depth marked on the geology map. The company had not noted this in its planning submissions. A more detailed analysis for my 2016 *Solid Earth Discussions* paper showed, using the Balcombe-1 logs as a proxy for Balcombe-2, that a normal fault was indeed cut through; however the throw (displacement) is only about 10 m, not the 30-40 m I had suggested in 2013.

5.3.3 Celtique Energie proposals at Wisborough Green and Fernhurst, Sussex

Celtique Energie disingenuously represented both its planning applications in the Weald Basin used the same 8 km long sample of seismic data for both of its planning applications, at Fernhurst (PEDL231) and at Wisborough Green PEDL234). Best practice, in contrast, is to illustrate the proposed wells by a seismic line running *through* each well. I compared the original version of the sample seismic data (Figure 5.5) with the reprocessed version presented by Celtique

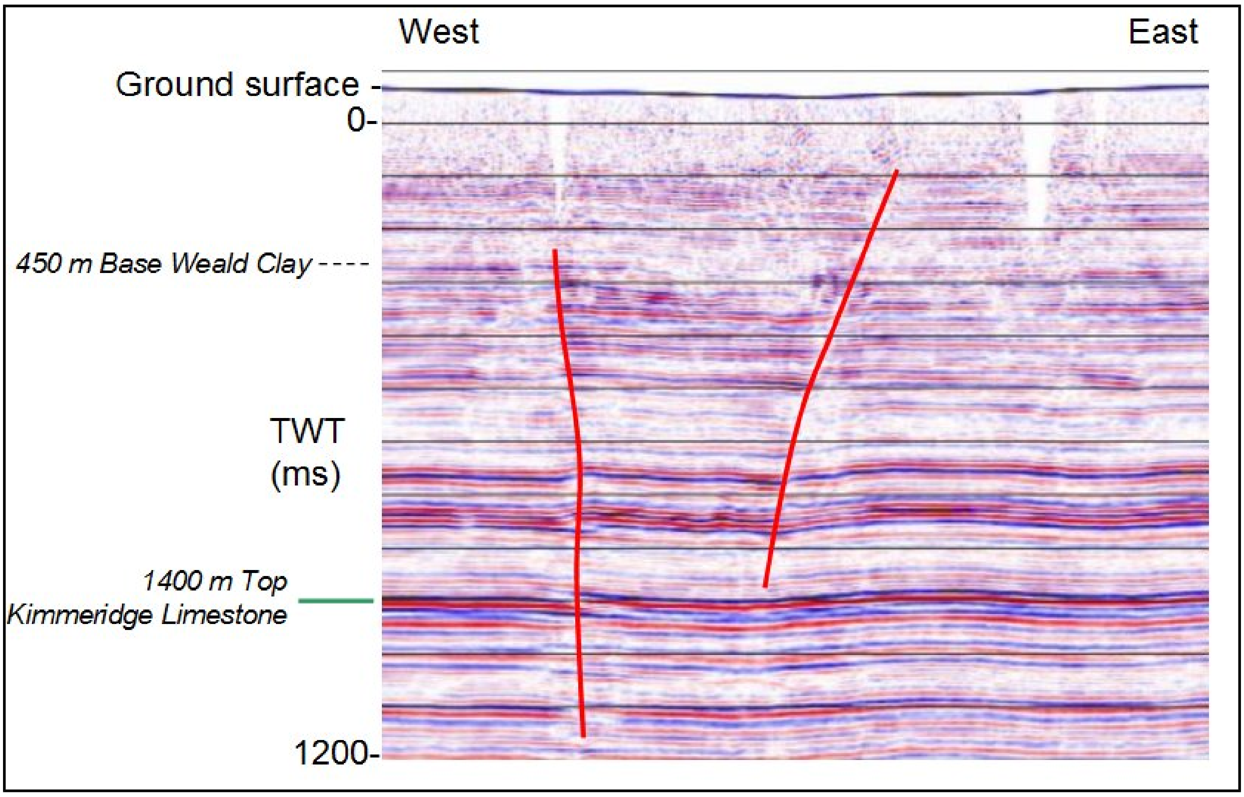

Figure 5.5. Detail of the the original version of the seismic line used by Celtique Energie in PEDL231 and PEDL234 purporting to demonstrate flat, unfaulted geology. Interpreted faults are shown in red. The same line also has evidence of a deeper fault.

The reprocessed version used by Celtique has a smeared-out quality; the fine detail of the faulting has been obliterated. There are two faults in the Middle Jurassic and Lower Cretaceous, extending upwards at least in one case into the Weald Clay. This is important evidence, because the Weald Clay is supposed to act as the impermeable cover-rock layer to prevent any upward migration. Celtique may have sought to mislead the county council and/or the public by presenting its reprocessed data as showing evidence for a lack of faulting.

5.3.4 Cuadrilla at Preese Hall, Lancashire

Drilling of Preese Hall-1 in 2010-11 triggered two earthquakes on a previously unrecognised fault. The company's 3D seismic survey which identifies the fault was only acquired a year later. Cuadrilla published a paper in which the fault plane was mapped, based on the 3D seismic image and the hypocentral location of a later earthquake assumed to have occurred on the same fault and recorded by the temporary network of seismometers installed after the first two tremors.

Cuadrilla's interpretation and my re-interpretation are shown side-by-side in Figure 5.6.

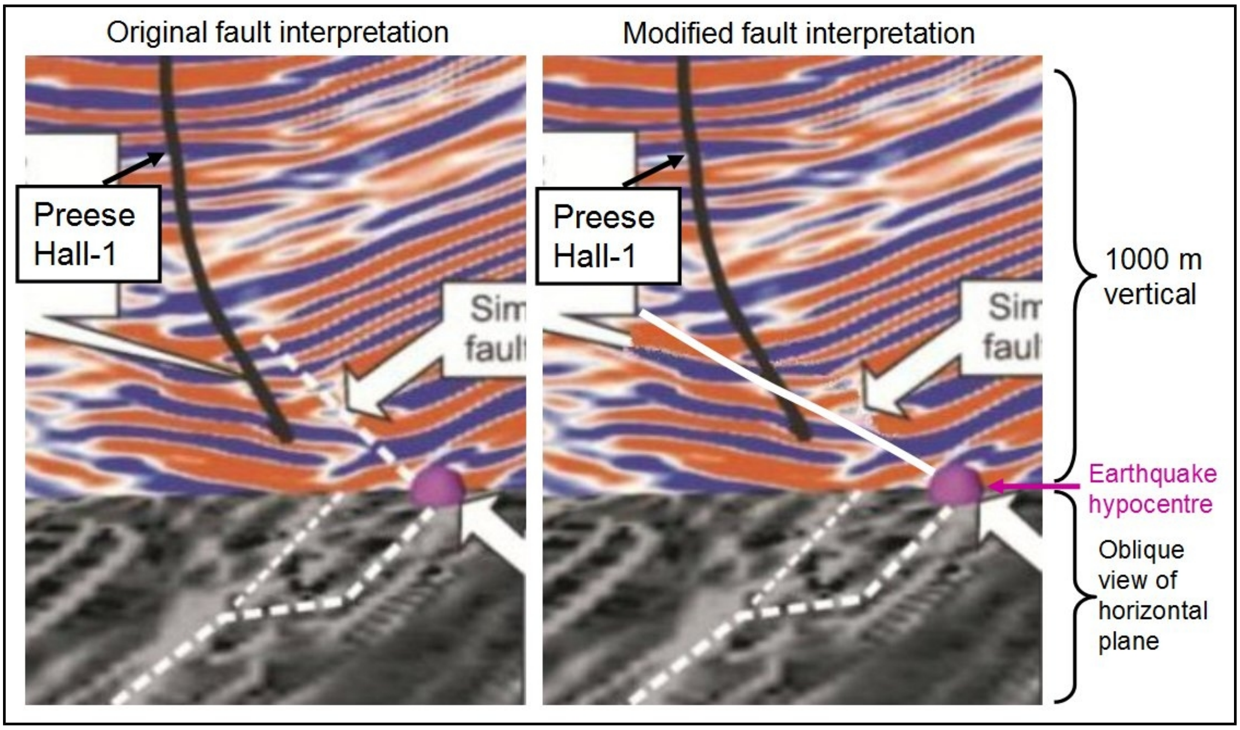

Figure 5.6. Preese Hall-1 well (from my Solid Earth Discussions paper). The left hand side shows Cuadrilla's original fault interpretation (white dashed lines) on a vertical seismic reflection plane (colour) aligned E-W, joined to a perspective (foreshortened) horizontal depth slice (grey). The earthquake hypocentre is shown by the lilac ball at the intersection of the two planes. The lower part of the wellbore is shown by the black line

On the right the original fault interpretation on the vertical plane has been digitally removed and replaced by the modified fault interpretation (solid white line), which avoids crossing continuous seismic layering and instead runs up and to the west between two distinct zones of different seismic layering dip. This shows that the fault intersects the well.

My reinterpretation suggests that the offending fault on which the earthquakes were triggered was penetrated by the wellbore, contrary to Cuadrilla's version. I have also shown that the relocated fault cuts the wellbore where the flattening of the wellbore casing occurred due to the stresses released by the seismic slip.

5.3.5 IGas at Springs Road, Misson, Notts

IGas presented misleading geological cartoons (they do not deserve to be called cross-sections) purporting to show that the drillsite sits on thin Mercia Mudstones above the Sherwood Sandstone Group, a Principal Aquifer for the entire East Midlands. The IGas version of the geology omitted the presence of a previously unidentified fault which I infer from the numerous shallow boreholes in the locality. I call this the Misson Fault (Figure 5.7).

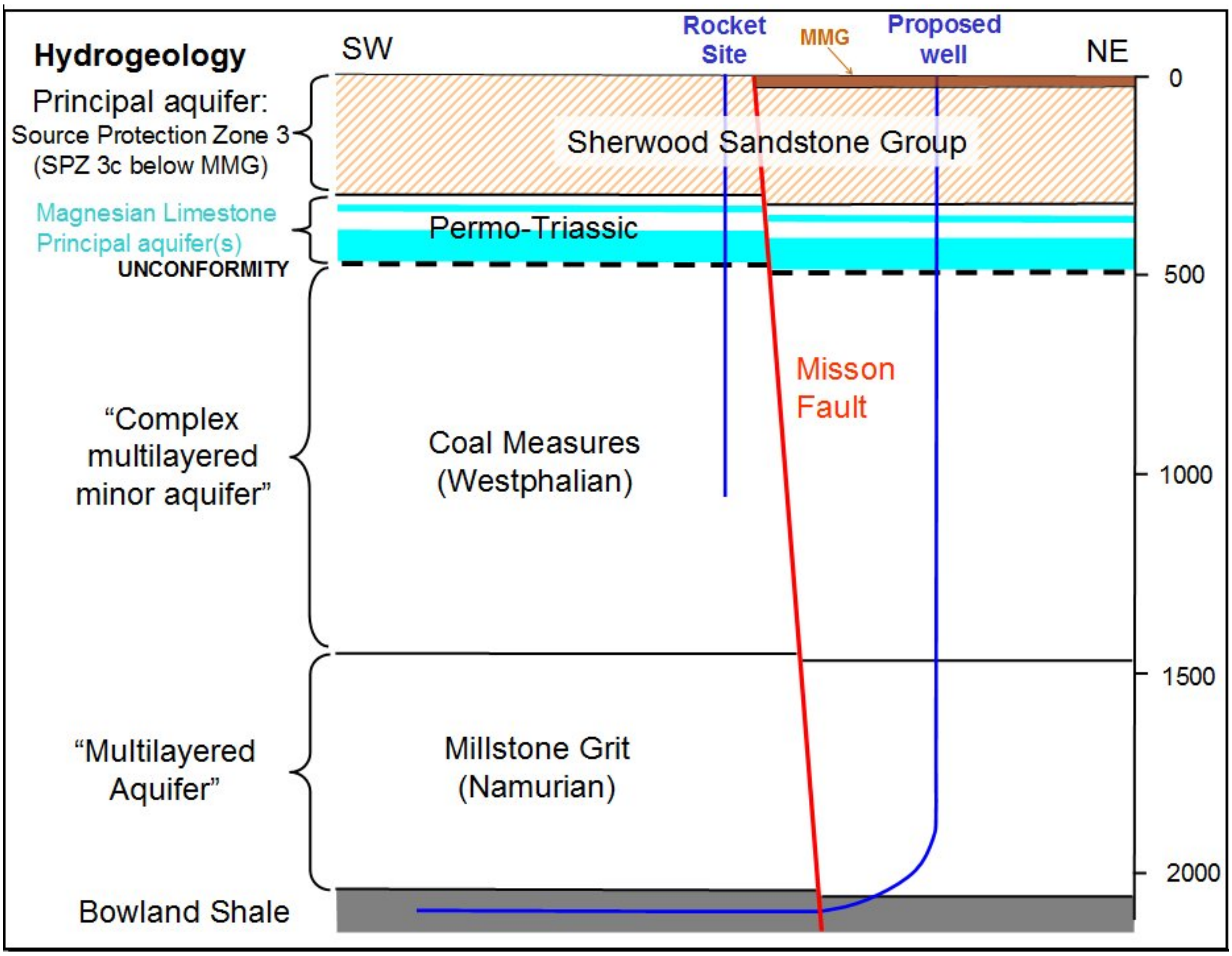

Figure 5.7. Properly scaled cross-section along the line of the proposed horizontal borehole at Misson Springs, for comparison with the Applicant's cartoons. No vertical exaggeration. The Rocket Site borehole is projected onto the section from 55 m to the SE. The position of the Misson fault is uncertain by about ±150 m either way along the section from its marked place, but it has to lie to the NE of the Rocket Site borehole. There is an arbitrary slight hade (angle from the vertical) on the downthrown side, and I have retained a constant estimated 30 m throw for the whole depth. Summary hydrogeological information is shown on the left.

The existence of this fault presents a real risk of contamination of the Sherwood Sandstone and Magnesian Limestone aquifers in the topmost 500 m. But instead of recognising this risk, the EA comments on the application concerned itself with portable toilets:

> "*The planning application states that all foul water from any site compound including temporary toilets would be disposed of to the onsite foul drainage system, this system currently consists of a septic tank. An assessment should be made of the septic tank to ensure it has the requisite levels of treatment to deal with an increase in effluent volume and possible change in effluent quality without causing pollution to surface or groundwaters.*"

5.3.6 Cuadrilla at Preston New Road, Lancashire

Cuadrilla is currently drilling at Preston New Road, Lancashire. It intends to frack two horizontal wells as shown in its Environmental Statement diagram. This is reproduced here as Figure 5.8, with a detailed view of the likely flow pathways up a fault.

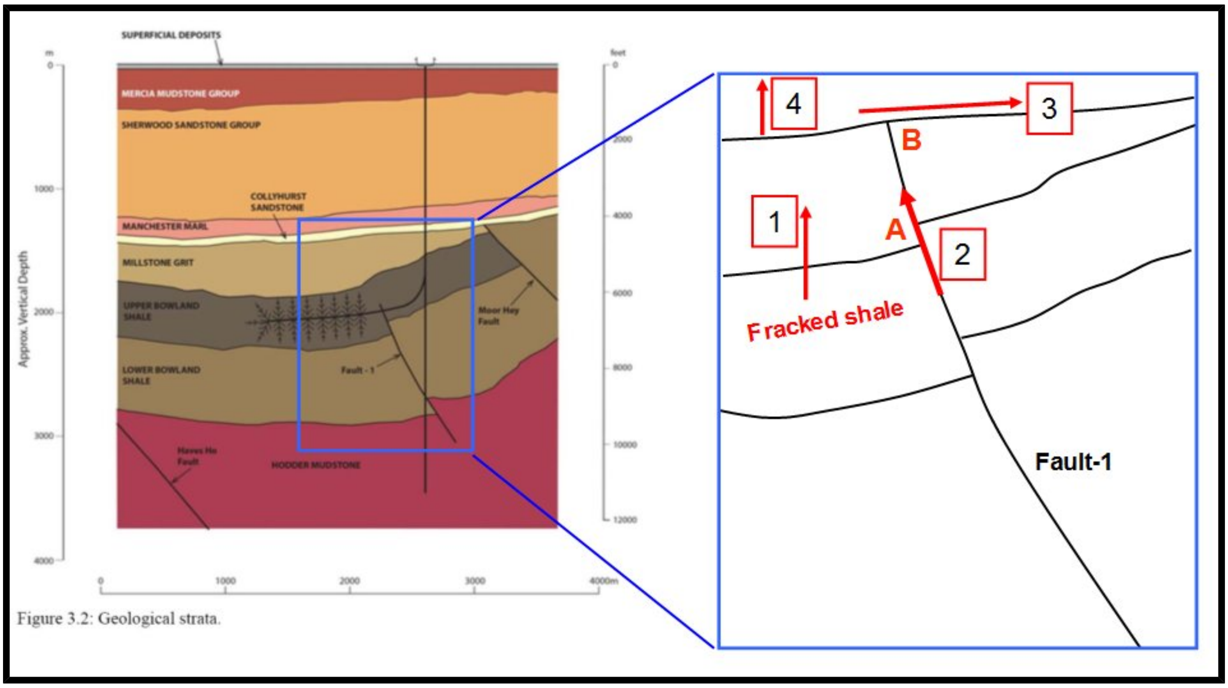

Figure 5.8. Cuadrilla E-W cross-section showing proposed fracking zone at Preston New Road. There are four possible flow pathways for upward contamination (detail on right) of which no. 2 is by passage up Fault-1.

Here it is evident that Cuadrilla will drill through a fault, labelled Fault-1, adjacent to the proposed shale fracking zone (dark brown layer in Figure 5.8). Its interpretation of the seismic data suggests, wrongly in my view, that Fault-1 does not conveniently peter out upwards within the shale, but probably carries on upwards to the base of the Collyhurst Sandstone (the thin yellow layer in Figure 5.8). The overall plan to frack in the Fylde also depends on the weak conclusion by the EA that the Sherwood Sandstone Group here (orange layer in Figure 5.8) is entirely non-potable.

5.3.7 Cuadrilla at Roseacre Wood, Lancashire

Cuadrilla's proposals at Roseacre Wood, Lancashire, are even worse than at Preston New Road. There is even more complex faulting as shown in the cross-section of Figure 5.9.

The zone to be fracked is only 1-2 km west of the major Woodsfold Fault. To the east of this fault lies the Sherwood Sandstone Group at the surface (below superficial deposits). This is the major Principal Aquifer for the whole of NW England. Cuadrilla's proposals, supported by the EA, assume that the Woodsfold Fault will be a barrier to fluid transmission. Not only is this view unfounded because it is based (a) on no evidence, and (b) conflicts with the EA's own groundwater modelling showing that other faults in the aquifer are transmissive to groundwater; it is also at odds with the evidence from former groundwater wells in the area west of the fault that suggest that the confined Sherwood Sandstone aquifer is fresh.

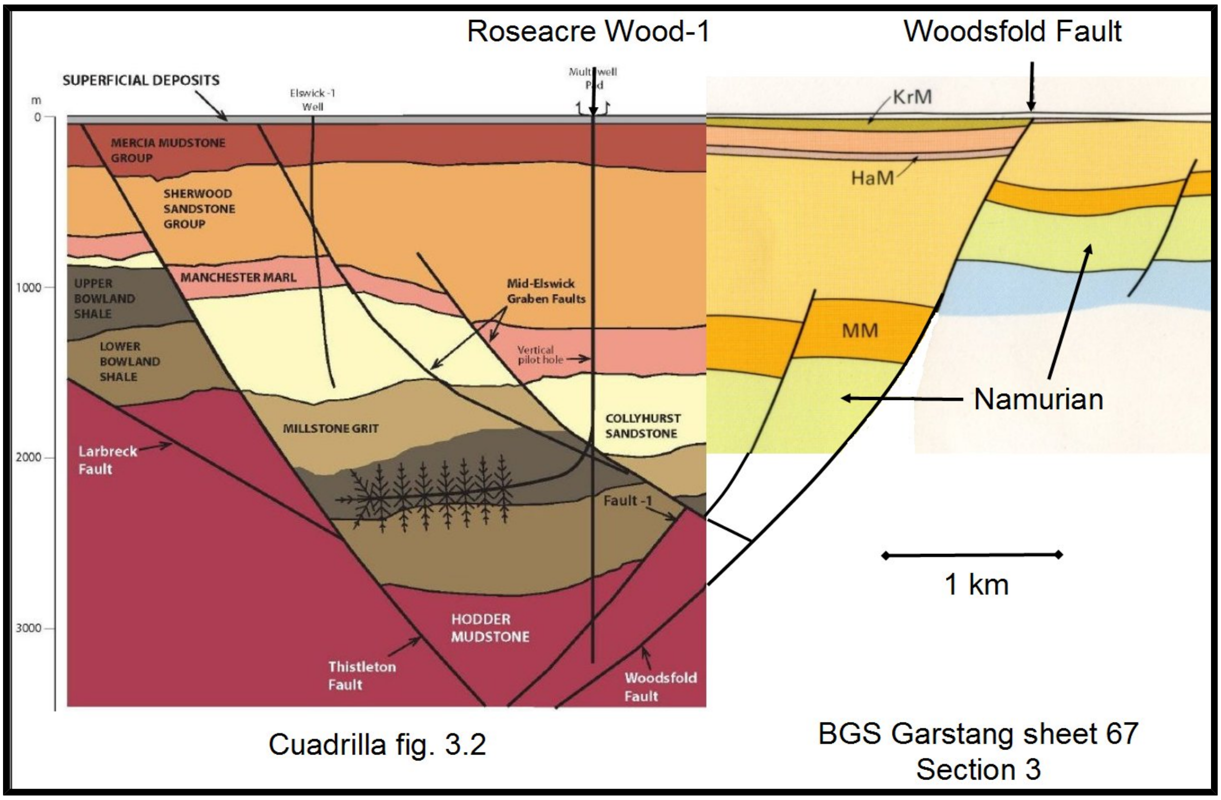

Figure 5.9. E-W cross-section of Cuadrilla (left) married to the BGS map cross-section (right) showing proximity of the proposed fracking zone at Roseacre Wood to the major Woodsfold Fault.

5.3.8 KImmeridge Oil and Gas Ltd at Broadford Bridge

Kimmeridge Oil and Gas Limited at Broadford Bridge, Sussex, is currently constructing a rig to drill obliquely to the limestones within the Kimmeridge Clay (Figure 5.10).

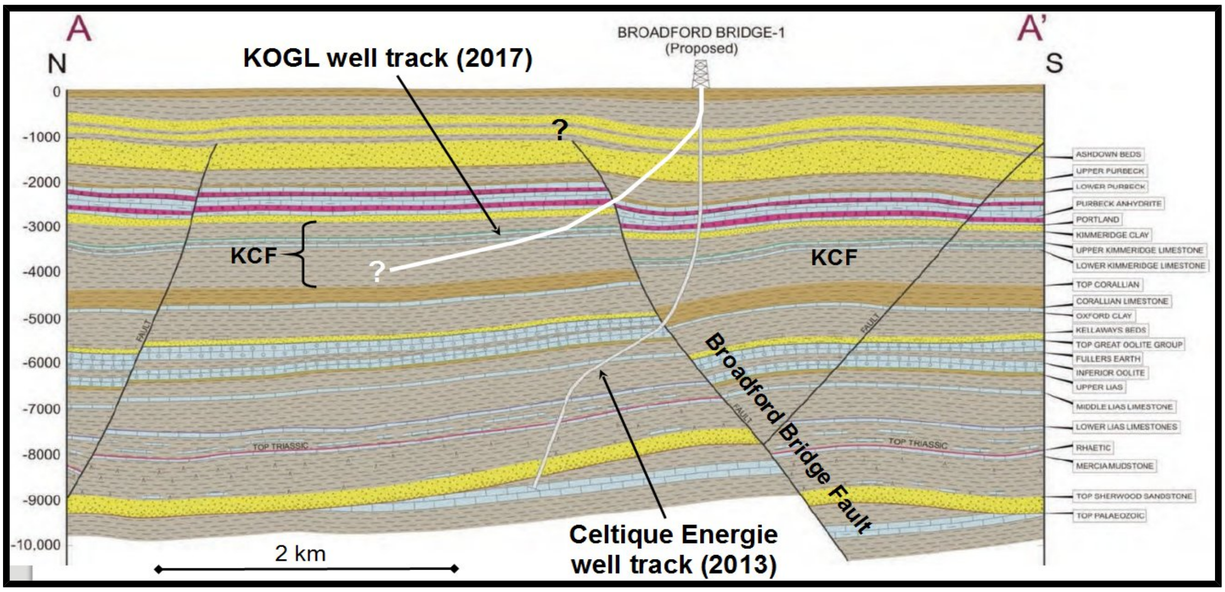

Figure 5.10. Kimmeridge Oil and Gas Limited proposal to drill an oblique well (white welltrack) to test the Kimmeridge Clay Formation (KCF). But the EA permit is only for the now-defunct Celtique Energie proposal to drill to the conventional Sherwood Sandstone target (grey well track).

This is in defiance of the lack of permit for the requested variation. The original permit was granted to Celtique Energie to drill a deviated well to test a conventional target, the Sherwood Sandstone. KOGL will traverse the Broadford Bridge Fault at around 600 m depth without any control whatsoever by seismic imaging (Smythe 2017). KOGL's actions are treating the regulators with contempt.

5.4 Discussion

The examples I have submitted herein show that contamination *via* faulting may be a major risk in the UK geological context. This is a separate issue from the triggering of earthquakes by fracking, which I consider to be of minor importance.

5.4.1 The specious counter-example of the Selby Coalfield

Professor Paul Younger of the University of Glasgow published a review article in 2016 with the tendentious title '*How can we be sure fracking will not pollute aquifers? Lessons from a major longwall coal mining analogue (Selby, Yorkshire, UK)*'. He stated that:

> *"the focus in this paper is on a very particular hydrogeological risk: that freshwater aquifers could be polluted by upward migration of contaminated fluids through **vertical fractures induced by the fracking process**."* [my emphasis].

Although this statement seems to make it clear that he will concentrate on fracking-induced fractures, he does later on introduce the topic of natural (pre-existing) geological faults.

He also repeats the old canard that fracking of onshore conventional oil wells has been carried on in the UK for decades, despite admitting that only one unconventional shale gas well has been fracked to date. What he slides over here is the distinction between conventional fracking (including of geothermal and water wells) and unconventional high-volume fracking. They are as different as a bicycle is from a Lamborghini.

He then discusses the potential for pollution of water resources by mine waters (his own area of expertise as a hydrogeologist), and arrives at the Selby Coalfield, the case study alluded to in the title of the paper. The two maps he includes are little more than sketches. The schematic cross-section also depicted lacks faults, as do the maps. He provides a detailed account of the mine development and hydrogeological problems, and compares the damage done to the subsurface by coal extraction with the fracking process. He demonstrates, quite reasonably in my view, that the former is far more serious than the latter, and since there has been little or no evidence of groundwater pollution during or since the Selby mining activities, he then concludes that fracking is a safe procedure, and that the hydrogeological risks will be minimal.

The possibility of pre-existing faults acting as conduits is a completely separate issue from that of the hydraulically-induced fractures created by the fracking process. But Professor Younger's review of Selby appears to employ a sleight-of-hand regarding the extensive faulting in the coalfield. On the lessons to be learned from Selby, he states:

> "*at no point during the working of the mine did intersection of faults lead to significant increases in water ingress ... the mere presence of faults does not mean that hydraulic continuity will be established; contrary to the claims made (e.g., Smythe 2014a, b, c) in recent shale gas and coalbed methane planning hearings in Scotland.*"

The clear implication is that extensive faulting at Selby did not create a problem, and, therefore, nor should it during unconventional hydrocarbon development.

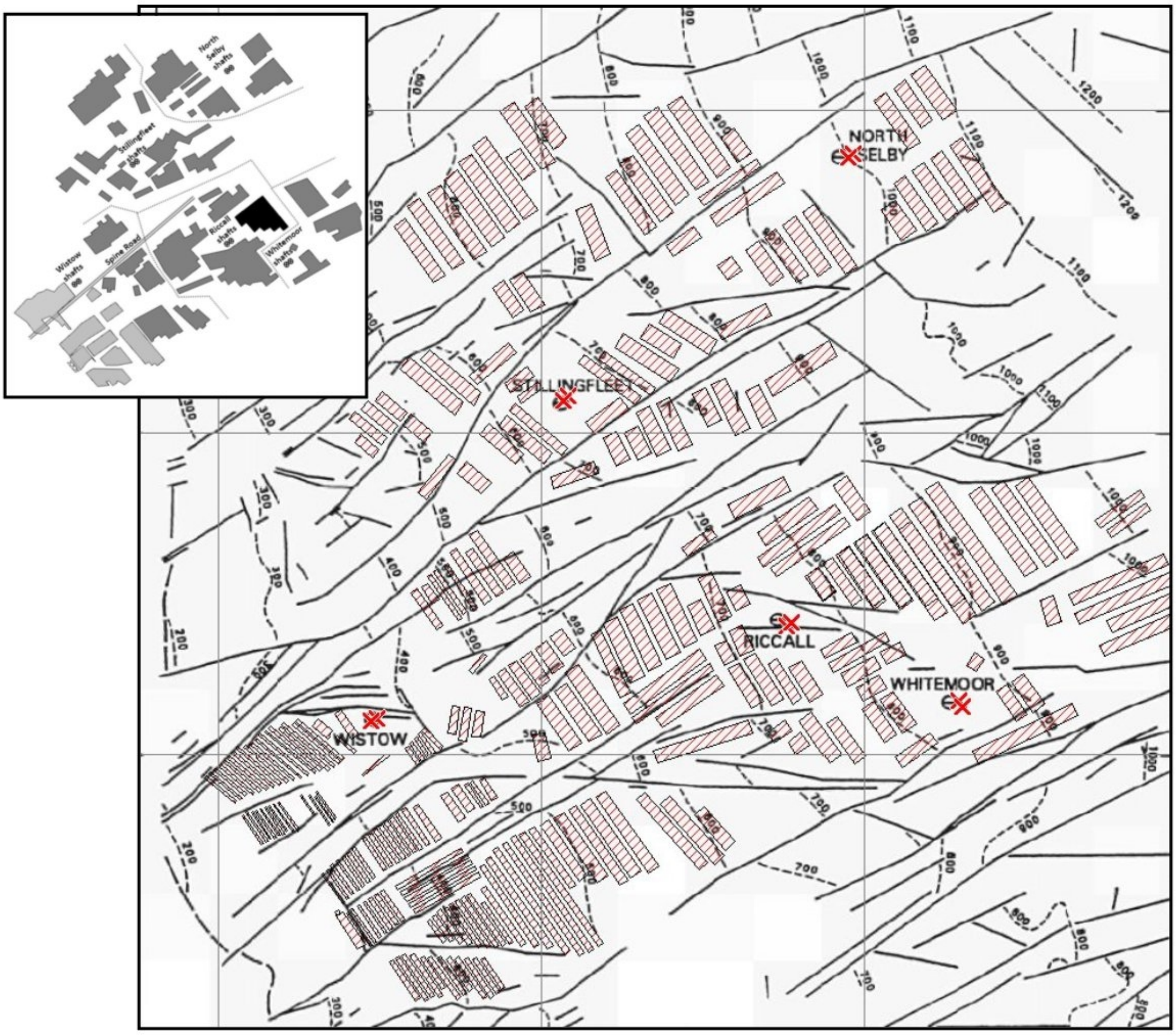

Figure 5.11. Worked Barnsley seam coal panels at the Selby mine (red cross-hatching) superimposed on fault map (solid black lines). The entry shafts to the five mines are shown by pairs of red crosses. Note that the panels (where coal was removed) avoid all the faults. National grid at a 5 km interval is shown. The inset map shows Younger's version, in which each block depicts a group of several rectangular longwall panels, and the faults are omitted.

Figure 5.11 shows the extensive faulting of the Barnsley coal seam, with the coal working panels superimposed as red cross-hatched areas. It can be compared to the sketch provided by Professor Younger, shown in the inset, in which no faults are marked. The detailed fault map shows that all of the coalmine workings were laid out to avoid the faults, these having been mapped in detail prior to the exploitation of the coal. So the question of whether faults act as transmission pathways cannot be addressed by appeals to the Selby experience.

Professor Younger, by omitting all details of the faults, tries to give the impression that they never gave rise to any but local problems when they were - very rarely - intersected by undergound workings. He jumps to his general conclusion from Selby that "*there are no <u>prima</u> <u>facie</u> geomechanical, hydrogeological or geochemical reasons why unconventional gas resources in northern England and Scotland could not be developed without causing aquifer pollution.*"

In my view his conclusions are misleading. If he wishes to maintain his account he should provide considerably more details of which faults were indeed intersected, along with information on how high up the geological layering the offending faults penetrate. Did they, for example, cut the aquifers above the Coal Measures?

5.4.2 Safe operating distance from faults

It is remarkable that UK legislation has avoided all regulation of faults as conduits, as opposed to faults as sources of seismicity. The fact that such a safe distance, also termed a *respect* or *stand-off* distance, needs to be defined is an implicit admission that faults may be pathways for contamination. It also begs the question of how these faults will be imaged and avoided.

Professor Peter Styles of the University of Keele presented a paper in co-authorship with Cuadrilla and its subcontractors (Styles *et al.* 2015) at a symposium in Davos, 10-13 March 2015. It is noteworthy from his slideshow that Styles said he was is in the process of making "*Preliminary Recommendations to UK PM's Office*" (slide 20 reproduced as Figure 5.12 below), while at the same time he is working closely with the nascent UK unconventional shale industry and its subcontractors.

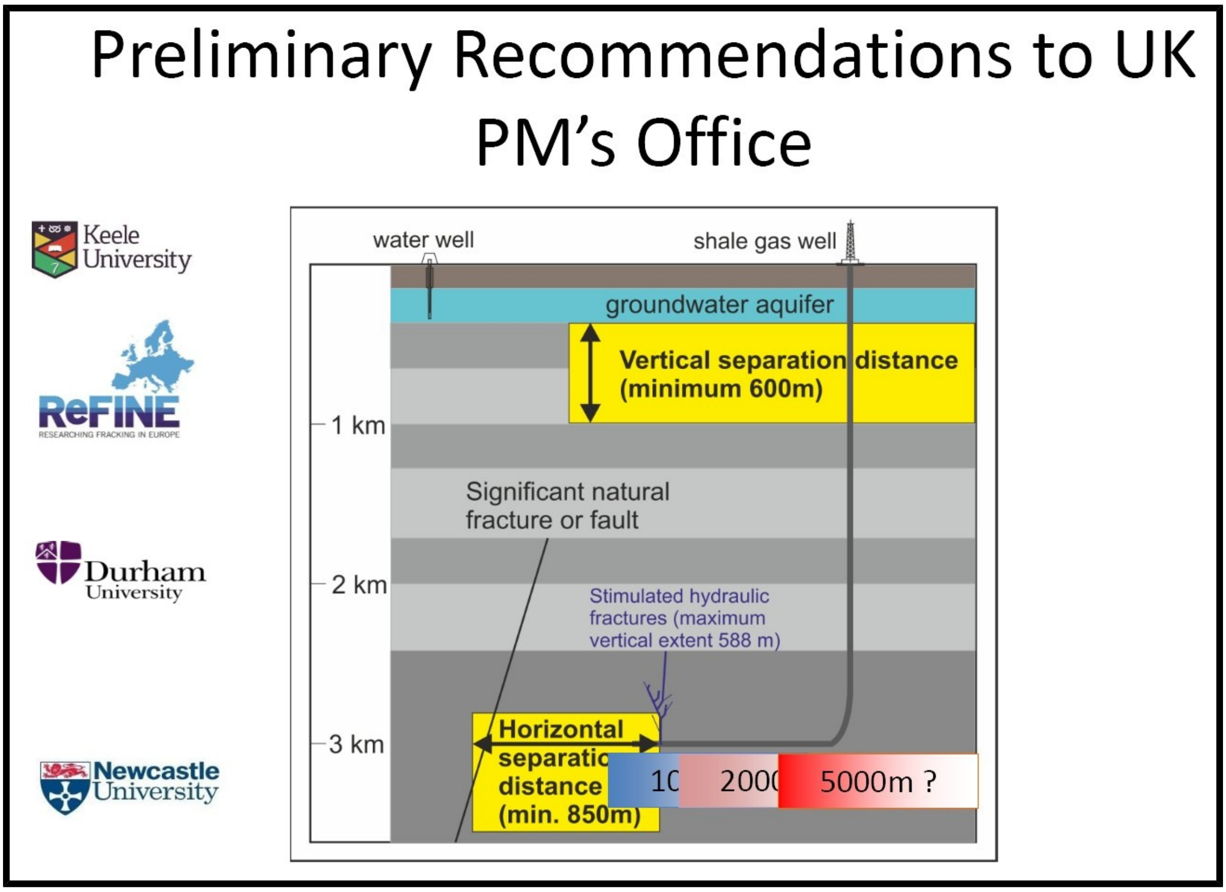

Figure 5.12. Slide no. 20 from presentation by Professor Styles showing proposed separation distances (also called respect or stand-off distances) from a fault, varying from 850 m to 5000 m.

The four authors of the Davos presentation are the same four who wrote the Preese Hall-1 earthquake paper, but with a different lead author. I therefore question Styles's independence from the industry, and why he alone seems to have the ear of government on this issue, without wider consultation and open scientific discussion. Nevertheless, he depicts a possible stand-off distance varying from a minimum of 850 m up to 5000 m.

Even if the minimum value of 850 m were to be adopted, it would rule out both developments in Lancashire from taking place at all. This is further evidence that much new legislation and scientific research must be carried out before any test fracking takes place.

PetroQuest Energy Inc., in a powerpoint submission from 2008 to the US Securities and Exchange Commission, states (Appendix, slide 8) on a diagram showing horizontal drilling through the slightly faulted Woodford Shale, Oklahoma, that "*Wells are typically TD'ed when faulting out of zone*". TD (total depth) means that the well stops there. The faults shown in that and the succeeding slide are typically 5 m or less in vertical throw, cutting the shale which is 20 m thick.

Best US fracking practice, according to a Distinguished Lecture sponsored by the Society of Petroleum Engineers, is to "*Avoid faults and geohazards*".

DECC was asked by LCC to comment on my two submissions to LCC on Preston New Road. John Arnott of DECC responded on 17 November 2014, by writing firstly, that the bulk of my submissions concerned possible aquifer contamination and was therefore outside the scope of DECC's remit. That was a matter for the EA. However, on faulting, Mr Arnott wrote:

> *"First, it is said that all faults should be avoided, whatever their scale. So far as hydraulic fracturing is concerned, we would in general agree with this principle. However, from the viewpoint of seismic hazards, we do not think there is any need to be concerned about drilling through a fault, as opposed to hydraulically fracturing into or near a fault. Drilling, as such, is not in the experience of the oil industry an operation associated with seismic activity. We are not aware of any factor in the geology around the proposed drilling sites which should require avoidance of all faults, so far as the drilling phase of operations are concerned. (The paper cites a large German study in support of the proposition that all faults should be avoided. However, the relevant conclusions of the German study refer only to hydraulic fracturing and not to drilling operations.)*
>
> [...]
>
> *We will scrutinise the Hydraulic Fracturing Plans and the plans for monitoring the growth of the fractures to ensure that the stimulated rock volume does not extend too close to any of the mapped faults.*
>
> *Third, is said that faults should be assumed to be transmissive unless proved otherwise. This comment is not directly relevant to seismic hazards, but as noted above, the purpose of the HFPs and their scrutiny by DECC is to ensure that the full extent of the stimulated rock volume preserves a safe distance from any detectable fault. The fracturing fluids will therefore never enter the fault, and will not be transmitted along it.*
>
> *Fourth, it is said that Cuadrilla's definition of faults is defective. However, the purpose of the definitions adopted is to distinguish between "local" faults, which*

Cuadrilla propose to drill through, and regional faults, which they do not intend to drill through. As noted earlier, we do not see drilling through faults as material to the assessment of seismic risk. As to the location and extent of fracturing operations, which are very material, Cuadrilla plans to avoid all detectable faults, which is the correct approach." [my highlights in red]

In summary, DECC's view here is that Cuadrilla is free to define 'local' and 'regional' faults as it sees fit. DECC will trust Cuadrilla to adhere to a HFP, scrutinised in advance, *but not scrutinised in real time as the frack jobs proceed*. Lastly, no quantification is provided of what is meant by 'too close', 'safe distance', 'avoid', and 'detectable'. I consider DECC's view, as expressed in Mr Arnott's letter, to be complacent. There is as yet no UK regulation of how a safe operating distance should be defined.

It should be noted that, however precise the real-time microseismic monitoring to monitor the progress of fracking may be, it is possible that frack fluid may proceed silently up a so-called *stealth zone* or pre-existing fault. The existence of the fault can only be inferred some hours later by the fact that the cloud of microseismic events has abruptly shifted. But no microseismic events record the passage of fracking fluid along the fault, because no rock has been split open in the fault zone; that segment of the fracking process is, paradoxically, *aseismic*. Such behaviour shows that it is crucial that fracking be avoided in all rock volumes containing faults.

If legislation were to be introduced to make a safe distance mandatory, then even if this distance were as little as, say, 1000 m, most if not all of the shale basins in the UK would become no-go zones in their entirety. That appears to be why such prescriptive legislation is being avoided.

5.4.3 Disposal of wastewaters

Wastewaters, in the UOG context, comprise *flowback* water coming back up during or just after the fracking process itself, and *produced water*, produced as a by-product of the oil or gas production.

The 2012 joint societies' report considered wastewaters in some detail, including final disposal by injection into dedicated wells. However it said little about the seismicity induced by such disposal, possibly because the gravity of this side-effect has only come to the fore in the last five years. The report also touched upon marine disposal, discussed below and in Appendix 2.

The EA used to take the view that disposal by onshore injection would be prohibited, but it seems to have recently come round to the opposite view.

Professor Ernie Rutter, who was the geologist on the Shale Task Force, told me last year that marine dumping was being considered as an option for flowback/produced water (hereinafter 'wastewater') from fracking. In February 2017 I prepared an aide-mémoire on the question of marine dumping for the All Party Parliamentary Group on shale gas. This is reproduced in its entirety as Appendix 2. It is a question for the lawyers as to whether large-scale dumping of a new form of toxic waste, including the radioactive elements contained in fracking wastewaters, is permissible under international law.

It is well established that re-injection of produced water into deep disposal wells can and does trigger serious earthquakes, in contrast to the fracking process itself where any earthquake triggering will be minor. It seems to me that the putative development of fracking industry in Scotland will mean that the Scottish Government is caught between the devil and the deep blue sea - that is, between underground injection or marine dumping. An alternative would be wholesale reprocessing of the produced water for re-use, but a comprehensive 2017 report (free pdf download, but valid email address required) from the combined US National Academies of Sciences, Engineering and Medicine shows that such a possible solution is at the very early stages of research.

5.4.4 Polyacrylamide in slickwater fracking

The EA, in granting the Preston New Road permit in January 2015, wrote:

> *"The hydraulic fracturing fluid will only contain additives which have been verified in writing by us as non-hazardous, the hydraulic fracturing fluid will include a friction reducing agent (polyacrylamide) which is present in the hydraulic fracturing fluid at no more than 0.05% of the total volume and we have determined that polyacrylamide is non-hazardous"*

Polyacrylamide is a common chemical used in the water industry. In the oil industry is is used as a friction reducer, to make water 'slick', both in conventional wells and in fracked wells. In fracking for shale gas (or oil) high volumes of slickwater are used, hence the acronym HVHF (high volume hydraulic fracturing).

Cuadrilla used a friction reducer, FR-40, when fracking the Preese Hall-1 well in 2011. It declared that "This product does not contain any reportable hazardous components as defined in 29 CFR 1910.1200" This code belongs to the Occupational Safety & Health Administration of the United States Department of Labor. Presumably the UK did not have its own standard, administered by the Environment Agency and/or the Health & Safety Executive. It would be pertinent to ask whether this is yet another gap in UK fracking legislation**.**

FR-40 was supplied to Cuadrilla by CESI Chemical, a company which does not list this product. It is likely that it was obtained indirectly from Raven Chemicals Inc., a US company which does market FR-40, and other similar chemicals based on polyacrylamide, used in hydraulic fracturing.

Polyacrylamide is made from acrylamide. There has been scientific controversy for around thirty years about whether polyacrylamide can be degraded back to acrylamide. It turns out that some results apparently supporting the breakdown of polyacrylamide to acrylamide are better explained by the fact that there is always some residual acrylamide content after the manufacture of polyacrylamide.

Acrylamide is a highly toxic chemical, which can lead to endocrine gland disruption, cancer, nerve problems, decrease of lifespan, and so on. It is so toxic that the Maximum Contaminant Level Goal has been set by the US Environment Protection Agency (EPA) at zero. The World Health Organisation has set a guideline value of 0.5 µg/l of acrylamide in water (pdf), which it states may be present from the residual levels of acrylamide in the polyacrylamide used to treat drinking water. The state of Minnesota has set a much lower guide value (pdf), based on "protecting Minnesotans from cancer" of 0.2 parts per billion.

Since we are dealing with large volumes of polyacrylamide containing residual quantities of acrylamide, as used in hydraulic fracturing, it becomes important to estimate whether potential contamination of water supplies could occur. Here are some figures.

The proportion of polyacrylamide in fracking fluid is around 0.05% by volume, as stated above by the EA. In that polyacrylamide there is a residual 0.1% of acrylamide (SNF Floerger handbook pdf). So fracking fluid contains of the order of 0.00005% acrylamide, or $5.\ 10^{-7}$ in scientific notation. Let us now turn to the permissible upper limit of acrylamide in drinking water. We can ask: by how much do we have to dilute neat fracking fluid to bring it below the safe limit. Bearing in mind that the only real safe limit, according to the EPA, is zero, we adopt the conservative Minnesota value of a 'safe' upper limit, which in scientific notation is $2.\ 10^{-10}$. Then we simply divide the proportion of acrylamide in frack fluid by the safe limit to get the dilution factor; this is $5.\ 10^{7}$ / $2.\ 10^{10}$ = 2500. In words, neat fracking fluid will become safe to drink (as far as its acrylamide content is concerned) as long as it is diluted by at least 2500 times with pure water (Figure 5.13).

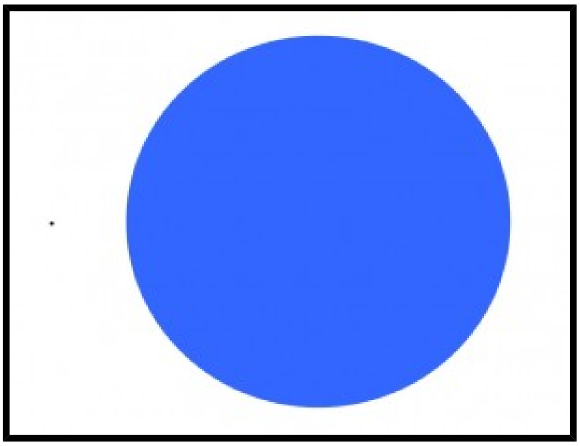

Figure 5.13. The blue disc is 2500 times larger in area than the black dot to the left, showing the factor by which fracking fluid needs to be diluted to make it safe to drink, as far as acrylamide is concerned.

Now we need to estimate pathways by which a given volume of the 60-80% 0f fracking fluid which is left in the subsurface could make its way via faulty wells, abandoned wells, or via natural faults and fractures into drinking water aquifers and wells. We would also need to estimate the volume of drinking water available in the given aquifer, and predict (by modelling) plausible mixing processes to see whether the fracking fluid is in fact diluted by a factor of 2500 or more, to render the drinking water safe.

One of the six fault modelling studies mentioned in Section 5.2 above, a Canadian study, found that the migrating frack fluid could reach the surface at up to 90% of its original concentration. So there could be localised pockets of contaminated groundwater with highly toxic levels of acrylamide. One cannot rely on natural mechanisms to dilute the invading frack fluid to safe levels in the aquifer.

The onus should be on the fracking companies to undertake this kind of study before even one well is fracked. But before this kind of modelling prediction could be considered meaningful they would have to have undertaken meticulous surveys in 3D of the geology of both the shale volume to be fracked, and of the rocks above and around.

Currently in the UK neither the regulators nor the fracking companies even consider the problem of acrylamide. Knowledge of geological pathways of the fracking fluid from the fracked shale back to the surface is either deliberately not sought, or else is ignored. On the subject of man-made pathways, the industry and the government fall back on the empty assertion that UK regulation is among the best in the world.

In conclusion, the precautionary principle implies that slickwater fracking, using polyacrylamides, should be made illegal, pending the outcome of a great deal more research.

6 Economics of natural gas

6.1 Introduction

If UOG cannot work economically, then all the discussion of environmental impacts, benefits and disbenefits to communities, security of supply and so on, becomes irrelevant, because the industry will simply not develop. I adopt two ways of examining the economics; firstly, the estimated costs projected into the future (the method employed in the SG consultation evidence base), and secondly, a summary of the global history of shale exploitation economics in the USA over the last fifteen years. Lastly I present new evidence, not covered in submissions to, or reports commissioned by, the DG, concerning whether the actual costs and timescales can realistically be applied to the UK in general and to Scotland in particular.

In the natural gas market there is an ongoing debate between two methods of pricing; oil-indexation *vs.* hub pricing. Two natural gas hub benchmarks of relevance here are the Henry Hub (HH) price, specified in US dollars per million British thermal units (MMBtu) and the UK National Balancing Point (NBP) price, specified in pence per therm. In the UK, the Gas Spot Price is commonly referenced to the UK National Balancing Point (NBP). In this model, gas anywhere in the national transmission system within the UK counts as NBP gas.

For the present purpose I convert the NBP sterling measure to the HH \$/MMBtu, using an approximate equivalence of 10 therm ≡ 1 MMBtu, because the latter unit is more commonly used. I also gloss over the difference in price between US oil, normally measured by the West Texas Intermediate (WTI) price, and Brent crude, the UK index. This is because the price spread (\$Brent - \$WTI) has been less than \$3 since the start of 2016.

Some of the links quoted below may be behind paywalls.

6.2 Costs of importing liquid natural gas

Figure 6.1 shows the historical hub prices from 2000 to April 2017. Note that the HH and NBP price converged up till about 2010, since when the HH price has been consistently lower. This is largely due to the increased production of fracked gas in the USA.

A Financial Times article from February 2016 pointed out that the cost of importing US liquid natural gas into Europe is cheaper than the UK wholesale price (Figure 6.2). Using the data from fig 6.1 for 2016 to extrapolate forward the graphs of Figure 6.2 shows that US LNG can be imported to the UK for the order of \$5/MMBtu, around the same price as the spot price for UK gas sold through the NBP hub.

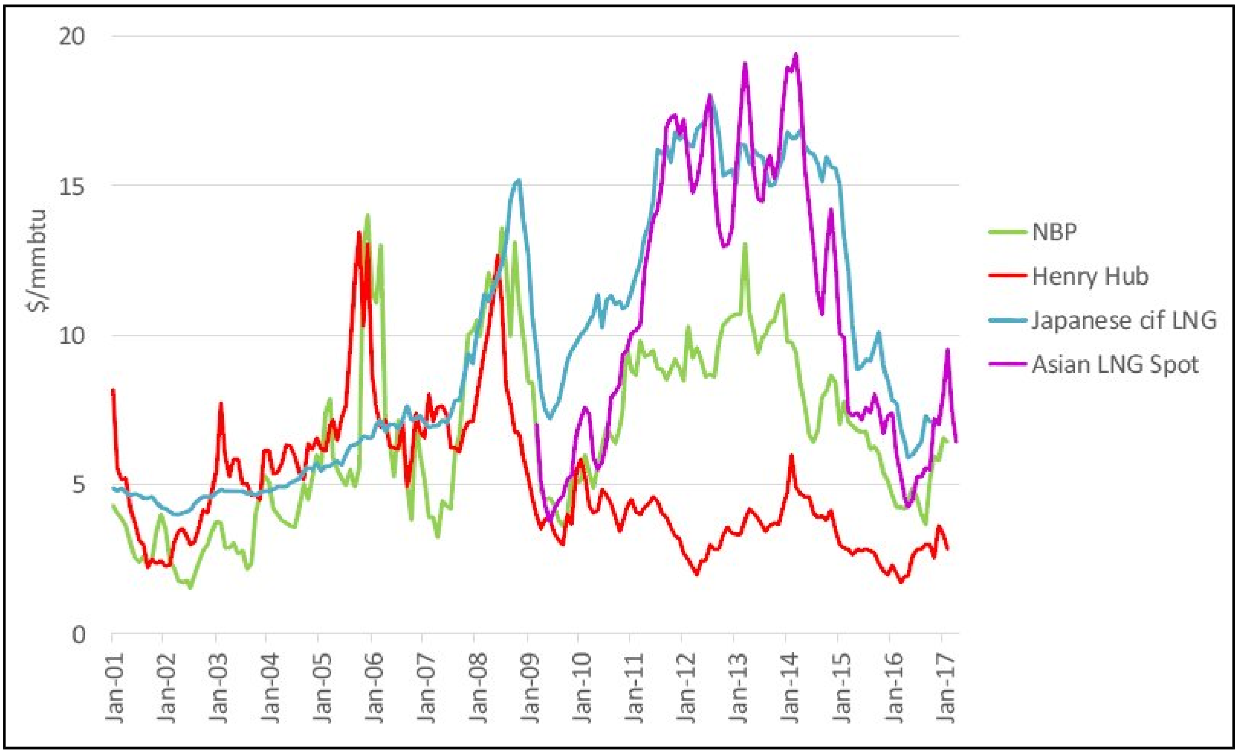

Figure 6.1. Historical gas hub prices 2000-2017 (Oxford Institute for Energy Studies).

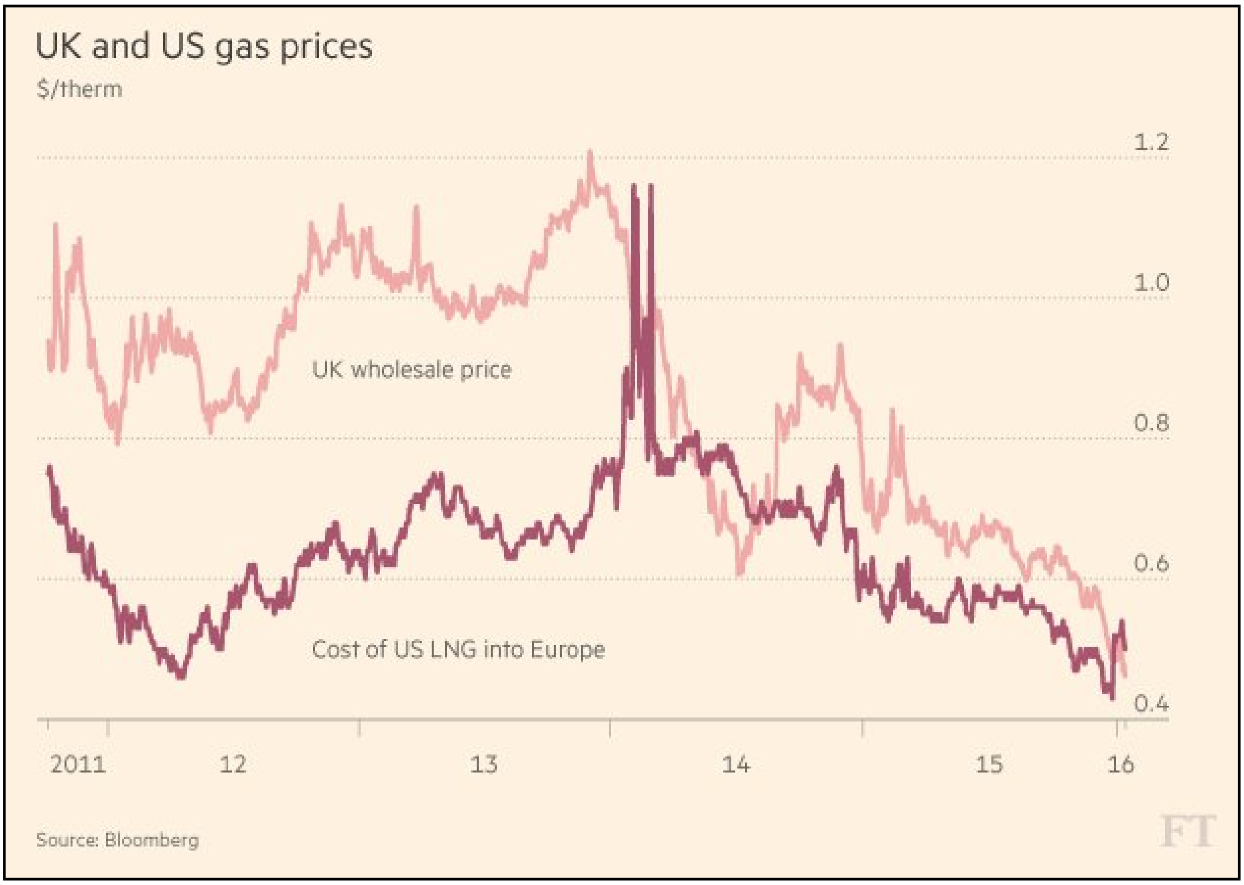

Figure 6.2. UK and US wholesale gas prices ($/therm). Multiply ordinate by 10 to get approximate $ price per MMBtu. (Source: Financial Times, 8 Feb 2016, paywalled).

6.3 Break-even cost

A *Financial Times* article from July 2016 quoted a Wood Mackenzie (oil consultants) study as concluding that the lowest-cost US onshore oil is to be found mostly in four unconventional plays, with break-even prices of between $35 and $48 per barrel. Specific prices quoted were the Wolfcamp - $39, and Eagle Ford - $48. A previous Wood Mackenzie report, from October 2015, had stated that the average break-even price for the four plays was $50, with the Wolfcamp at $52.

The implications of the above reports are that shale oil is becoming affordable relative to conventional supplies. But a more in-depth analysis by Art Berman, from June 2016, shows that the Permian Basin tight oil break-even price averages at $61, and that the Spraberry and Bone Spring reservoirs are mostly sandstones, while the Wolfcamp reservoirs are mostly limestones. They are not shale plays, and much of the earlier production was conventional (the Permian Basin was first exploited 50 years ago). He also demonstrates in a report dated April 2017, that the low current break-even price of oil, at below $40, applies not just to unconventionals, but to the major conventional companies as well, and has been driven by shale oil market: "*costs have fallen for everyone since 2014 as oil field service companies competed for limited projects by working at a loss*". In short, these claims of new low UOG production prices are not unique to UOG, and are not sustainable.

The controversy around oil-indexation has been induced by the shale gas market. Oil-indexation is the conversion from physically produced gas or gas condensate to a notional equivalent value in barrels of oil. The traditional conversion of 6:1 (e.g. $5 gas ≡ $30 oil, in US units), based on relative energy content, no longer holds, and other higher ratios such as 12:1, 15:1 or even 19:1 need to be adopted.

In conclusion, and in very round terms the break-even price for UOG in the USA are as follows:

- Shale gas: $5
- Tight oil: $60

The HH price has been below $5 since 2010, apart from a brief interval in February 2014 when it rose to $6 (red line in Figure 6.1). It is currently around $3. The tight oil price above is based on the historical 12:1 ratio, and also corresponds to analyses by Art Berman, including his recent study of the Bakken oil play where the break-even price ranges from $45 to $70 depending upon the assumptions. Recent claims of much lower costs for UOG are based on cherry-picking data and/or unrealistic assumptions.

The US gas can be exported to the UK for a similar price, as shown above. It may seem counter-intuitive that shale gas which costs of the order of $5 to break even is still being produced when it can only be sold for $3-4. This is explained in the next section

6.4 US shale gas economics

The KPMG report (2016), commissioned for the SG consultation, summarises the growth of US indigenous gas production due to the development of the UOG industry. But it nowhere mentions the overall costs of the industry, and whether or not it has been an economic success or not. But David Hughes and other commentators, including Art Berman, have shown that the US shale gas industry has never been financially viable.

David Hughes has produced several evidence-based reports on the economic realities of shale gas and oil production. His *decline curves* (the rate at which production from a given well declines over time) show that most of the production from an unconventional well occurs in the first 18-24 months. The wells are effectively dead after 5-8 years. Such steep decline curves are common to all unconventional wells, and there is no reason to believe that UK wells will be any different.

I have tried to quantify the economically disastrous shale gas bubble in the US, after reading an article at the end of 2015 which quoted the *Wall Street Journal* as saying that the onshore US shale industry (NB excluding the majors Chevron and ExxonMobil) was carrying debts of more than $200 billion. One can take the official monthly gas production figures from the Energy Information Administration, and multiply each by the historic Henry Hub gas price for each month. The figures are summarised in Table 1.

Income (expenditure)	**$ billion**
Historic gas sales	215
Drilling cost ($7M - $8M per well)	322-368
Royalties, leases, operating costs, interest etc.	?
Debt (excluding Chevron and ExxonMobil)	>200

Table 1. Total income and costs of US shale gas exploitation, 2007 - mid-2014.

From 2007 to mid-2014 the total raw gas sale value amounts to $215 billion. But the historic raw drilling cost for the approximately 46,000 horizontal gas wells, at $7M to $8M per well, is more than $100 billion higher, of the order of $350 billion. This figure excludes royalty payments (typically one-eighth, or 12.5%), lease costs, interest payments, and so on. Most of these wells are now over five years old. Because of the high decline rate of fracked wells, little additional income can be expected from existing wells. Therefore it cannot be argued that the investment has been made, and that significant income has yet to be generated.

These figures do not add up to a viable industry. In round terms, the costs of shale gas have been double the income generated. It has been a financial bubble, developed by unscrupulous companies. Here are two examples of the kind of person who has been prominent in the US shale industry:

> (1) Christopher Faulkner, self-styled 'Frack Master' and CEO of Breitling Energy, has appeared several times in the UK, promoting the benefits of shale production. But in July 2016 he and others were charged with fraud by the Securities and Exchange Commission of the USA. Faulkner is currently being held without bail in a Texas prison.
>
> (2) Aubrey McClendon was the founder and CEO of one of the biggest shale players in the US, Chesapeake Energy.. He apparently committed suicide by driving himself into a motorway bridge, the day after being charged with rigging bids for oil and gas drilling rights. He had previously been ousted from the Chesapeake board for cheating on his Chesapeake investments. McClendon left

behind debts of between $455M and $1 billion. Chesapeake has also been accused of cheating on landowner due royalty gas payments by 'logic-defying' expense charges.

The development of UOG in the USA has followed a boom and bust cycle. This industry is frequently touted as an example for the UK to follow, but in reality it has been a financial disaster, founded on private investment in small- and medium-size independent oil and gas companies. It is a Ponzi scheme, wherein new drilling (to keep up the high initial rate of production) is financed by pulling in new investment in the form of junk bonds. Investors are attracted by the annual dividend of around 6%, but they will never get their capital back.

Some 74,000 horizontal UOG wells have been drilled since hydraulic fracturing for shale gas and oil started in about 2003. At a minimum of $6M each, the costs of drilling are therefore at least $440 billion (but probably well over $500 billion if historic drilling costs are used).

The shale gas bubble peaked in 2011-2012, and by 2015 the *Wall Street Journal* reported that the total debt of the companies (excluding the majors Chevron and ExxonMobil) was in excess of $200 billion. The average productive life of wells is 5-8 years, with most of the production being achieved in the first two years. Therefore, since the majority of US wells are five years or more in age, they cannot be expected to produce much more. Five thousand of the Barnett (Texas) shale play's 20,000 wells are now 'shut in' (closed down). Even the recent slight rise in the price of oil has not saved the UOG industry from collapse; the Bakken oil shale play of North Dakota, for which UOG in the Weald is a close analogy, is now in severe decline since peaking in December 2014.

This is not the sort of industry that either the UK or Scotland should be encouraging.

6.5 UK shale production costs and timescales

A Greenpeace Energydesk report from August 2015 summarised then-available estimates of how much it would cost to produce UK shale gas. The range of estimates is shown in Table 2.

Source	Year	Low	High
Oxford Institute for Energy Studies	2010	49 6.4	102 13.3
Bloomberg (link no longer available)	2013	47 6.1	81 10.5
Ernst & Young	2013	53 6.9	79 10.3
Centrica	2012	46 6.0	-

Table 2. Estimates (2010-2013) of cost of UK shale gas production, from low to high. Figures in green are pence/therm from the reports; these have been converted to $/MMBtu (red) using $1.3 = £1.

The UK Onshore Oil and Gas group (UKOOG) envisages 100 drilling pads, each with 40 horizontal (lateral) wells, in a full-scale UK unconventional industry. But for drilling and completing one well it estimates, in production mode:

"- *a few weeks to prepare the site*
- eight to twelve weeks to drill the well
- one to three months of completion activities including between one and seven days of stimulation."

UKOOG then concludes:

"*This initial three- to five-month investment has the potential to deliver a well that will produce oil or natural gas for 20 to 40 years, or more*."

The quotations above, from the current UKOOG website, are identical to those to be found in its pdf handbook dating from October 2013. The time quoted above to drill one well seems to be too slow compared to US drilling times by between 4 and 7 times. However, even using the faster US figures, the drilling and completion time for 40 wells on just one pad, drilled by one high-tonnage rig will be around three years. Completion, using a 'spread' of up to 50 vehicles and employing 90-100 skilled personnel, is a small fraction (perhaps 10%) of this duration.

Unconventional oil and gas (UOG) development was initially developed in the late 1990s to break even at an oil price of around $80. The current break-even price of UOG is of the order of $60 per barrel of oil (or gas equivalent) in the best (i.e. most cost-effective) US unconventional play, the Permian Basin (see Section 6.3 above). The current price of benchmark West Texas Intermediate (WTI) crude oil is around $50. It has been as low as $30.

UKOOG's estimate that its specimen well would produce for "*20 to 40 years, or more*" is absurd, given the actual history of the rapid production decline of US wells. These wells last for 5 to 8 years, so UKOOG figure of 20 to 40 years is therefore misleading by a factor varying from 2.5 to 20.

The KPMG report has produced UOG development scenarios for Scotland, based on some unspecified planning application examples from England. Such a basis is immediately suspect, given that the English planning applications can be full of over-optimistic assumptions of the part of the developer (see Section 7). The KPMG scenarios appear to depend heavily on 'evidence' provided by the Institute of Directors report of 2013, sponsored by Cuadrilla (see Section 7.8).

The central Scottish scenario envisages 20 pads of 15 wells each, and each pad built over 11 years. Each pad is active in production for about 20 years. The outcomes of this and the other scenarios are highly sensitive to the assumptions made. Possibly the most serious error by KPMG is in assuming that each gas well will produce 3.16 billion cubic feet, its Estimated Ultimate Recovery, or EUR. In fact, US production history shows (based on data and analysis up to 2014) that a more likely figure is around 1.4 bcf/well. So the KPMG figure is too optimistic by a factor of greater than two. KPMG's assumption renders all their economic predictions and the accompanying timescales essentially worthless.

6.6 UK capital expenditure required

The capital expenditure which would be required for a viable UK shale industry is frequently overlooked. One heavy-duty onshore drilling rig suitable for horizontal drilling costs in the order of $40M. The ‘spread’, or fleet of vehicles and ancillary equipment required for 'completion' of the well, including fracking, costs in the order of $50M. Note that US equipment cannot simply be imported for UK use, because the vehicles are too wide, and with too great a turning circle, for the UK road network.

The hardware will have to be developed from scratch in Europe or the UK. In conclusion, the development of a fully-fledged UK or Scottish unconventional hydrocarbon industry will be too slow and cost too much. It should not be encouraged.

7 Failures of current UOG regulation

7.1 Multiple regulatory agencies

This section is concerned only with the geological and hydrogeological aspects of the regulatory process. Regulation of unconventional energy is split across four separate agencies or authorities. In order of action (although there will be some overlap) these are:

- Oil and Gas Authority (OGA)
- Local authority
- Scottish Environment Protection Agency (SEPA)
- Health and Safety Executive (HSE)

7.2 Issue of PEDLs by the OGA

UK oil and gas licenses (petroleum exploration and development licences or PEDLs) ar issued on a discretionary basis, formerly by DEn, DTI, DECC and currently the OGA, usually after a round of licensing. I am probably the only person ever to have sat on both sides of the table when prospective licensees are interviewed. In the past the system was reasonably robust. The main issue is how much resources the company will commit to the licence, if awarded. This is measured by promises to drill wells, definite or contingent, and to undertake seismic exploration. The target depths of the wells and/or the kilometrage of 2D seismic line surveyed have to be specified. A provisional commitment can be made, such that if the results of the initial studies are not promising, a contingent well will not be drilled, but then the licence lapses (the 'drill or drop' clause). The licensor (now the OGA) is not really interested in the fine details of the plays and prospects that may be outlined by the applicant.

The failure of this part of the system is that small 'cowboy' companies can nowadays apply for and obtain licences, with neither the requisite geological and technical background, nor with sufficient funding to cover their commitments. These operators are playing a game of licence winning, in the hope or expectation that one of the bigger and more experienced operators will buy them out - for example by 'farming in'. This is usually a financial commitment by the third party to share the costs of the drilling, in return for an equity. Some companies play fast and loose with reports of their alleged discoveries.

Examples of these practices include:

> *Coal bed methane (CBM) at Airth.* The interests of Coalbed Methane Ltd were taken over by Composite Energy in 2004, then by Dart Energy in 2011. Dart was in turn taken over by IGas in 2014. The thirty-year history of CBM at Airth seems to have comprised rather amateur and underfunded efforts to develop CBM. I called into question Dart Energy's technical competence at the Falkirk Planning Inquiry Appeal of 2014. It emerged during the appeal hearings that if a horizontal well through a coal seam hit a fault, and lost the seam on the other side, Dart's procedure was simply to drill on blind for up to a 12-hour shift. There would be no way of subsequently cementing off the slimline holes from connection to the fault zone. In short, Dart's action after the unexpected penetration of a fault and how it is subsequently dealt with is evidently more of a commercial than an environmentally sound decision. The latter approach would be to cease drilling immediately and plug the well.

IGas at Misson Springs, Nottinghamshire. The financial viability of IGas has been called into question, despite a $35M restructuring in March 2017.

Figure 7.1. IGas Energy PLC share price, five years to 26 May 2017.

The share price history shown in Figure 7.1 above suggests that the market has little faith in IGas. Note, for comparison, that the FTSE 100 index rose from 5200 to 7500 over the same period, generally smoothly upward despite a downturn in 2015-16.

Celtique Energie in Sussex. Celtique ended up in litigation with its partner Magellan Petroleum in its Weald Basin licences, and over the funding of the Broadford Bridge drilling in particular. Celtique sold its interest in PEDL234 to UK Oil & Gas PLC in 2016, as part of a settlement with Magellan.

UK Oil & Gas PLC at Horse Hill Surrey. UKOG claimed that 100 billion barrels of oil had been discovered in the Weald, or nearly five times the entire production of the North Sea (28 billion barrels) since 1975, by extrapolating from the well result which flowed at 456 barrels a day. Experienced oil industry commentators such as Euan Mearns have dissected and derided, using detailed analyses, the overblown claims made by UKOG for its Horse Hill discovery (the so-called 'Gatwick Gusher'), and conclude that the projections must include the entire 'LTO resource' - that is, the light tight (unconventional) oil present throughout the whole of the Kimmeridge Clay Formation, and not just the three thin micrite limestones. In other words, the claims refer to an unconventional shale *resource* (that which is present underground), which in turn is far greater than what might conceivably be extracted with current technology (the *reserve*). Why is a licensee permitted to try to manipulate the market by misleading claims?

These sorts of companies should play no part of a 'strong and stable' economy.

7.3 Local authority minerals planning application determinations

The burden falls upon the LMA – in practice, the planning departments of county councils - to decide whether or not a particular proposed drilling and fracking application is based upon sound geological data and interpretation; but county councils do not have the in-house expertise to make such judgments, and therefore have to rely wholly on what the applicant chooses to present. The councils have neither the time nor the money to seek independent advice. The time permitted for determining an application is sixteen weeks, but a requirement by the applicant to resubmit information or revised proposals has sometimes lengthened the decision time. Central government (in the person of the Secretary of State) called in the two Lancashire fracking applications and approved them himself, on the basis that fracking shale is part of the so-called 'National Infrastructure', and therefore too important to be left to county councils.

The geological aspects of the proposed drilling should be included in the applicant's papers, usually as part of the Environmental Impact Statement or Assessment.

Examples of failure or weakness of council regulation include:

> *Cuadrilla Balcombe Limited.* Cuadrilla originally received planning approval for a conventional oil target at Balcombe in 2010, but this subsequently became a Kimmeridge Clay target with test fracking. The planned fracking was later dropped by the Developer. Cuadrilla had to make a fresh planning application after public protests. The vertical portion of the well, Balcombe-2, went through a fault that I had predicted in 2013 from study of the BGS geological map, but of which the Cuadrilla was unaware.

> *Cuadrilla applications to drill and frack at Preston New Road and Roseacre Wood, Lancashire.* Comprehensive expert witness submissions by myself and others were marginalised and dismissed by the Officer Report of June 2015, which was issued just prior to Lancashire County Council's determinations. The councillors were put under undue legal pressure to accept the recommendations of the Officer Report. This disgraceful episode has been documented by Short and Szolucha, 2017.

> *IGas at Misson Springs, Nottinghamshire.* IGas eventually obtained planning consent from the County Council, despite the misleading geology represented in its submission (discussed in Section 5.3.5 above).

> *Angus Energy.* A new sidetrack well was drilled at its Brockham site without permission. Surrey County Council appears to be impotent to stop the development.

7.4 Environmental Agency and Scottish Environmental Protection Agency

These bodies are as statutory consultees to local minerals planning authorities, usually county councils. They have only a limited remit to issue (or withold) a permit, within the context of perceived risk to groundwater or air, for example. In addition, its hydrogeologists are not necessarily familiar with the bigger picture of shale basins, possibly two or three kilometres deeper than its zone of expertise of groundwater and surface water. In a shale drilling planning application the EA has to submit its report to the council within the sixteen-week period, and, like the county council itself, has neither the time nor the funding to seek outside advice. EA funding was cut by more than 20% between 2011 and 2015.

Examples of failure or weakness of EA or SEPA regulation include:

> *SEPA Canonbie CBM*. SEPA failed to realise until late in the day the importance of protecting the Sherwood Sandstone aquifer (Rob Edwards for the Sunday Herald, 2015). Greenpark Energy, the developer, had drilled unlined boreholes in 2011 which could act as upward conduits for pollution of the aquifer. SEPA's excuse was that the holes had not actually been granted a licence to produce gas.

Kimmeridge Oil and Gas Limited. KOGL has inherited the PEDL234 licence from Celtique Energie, and proposes to materially alter the terms of the planning approval granted to Celtique, in that a different, unconventional, shale sequence will be targeted instead of the conventional sandstone target for which Celtique obtained permission (Smythe 2017). At the time of writing the EA has not determined the requested variation of its previous consent, but KOGL has gone ahead regardless with erecting the drilling rig at Broadford Bridge.

The EA has progressively modified its views on disposal of flowback and produced water, as discussed in Section 5.4.2 above.

7.5 Health and Safety Executive

7.5.1 Cuadrilla at Preese Hall-1, Lancashire - failure to act on earthquake triggering

The location of the fault that was triggered by fracking in 2011 at this well is discussed in Section 5.3.4 above. It seems that HSE played no part in this episode, which is surprising. The triggering of earthquakes and consequent flattening of the wellbore, rendering the well unusable, should have been within the remit of HSE. Cuadrilla was subsequently criticised for technical incompetence and untrustworthiness as an operator by the the Energy Minister Charles Hendry.

7.5.2 Cuadrilla at Preese Hall-1, Lancashire - well integrity failure

A series of emails between Mr Mike Hill, a drilling engineer who worked on the well in 2010-2011, and the EA and HSE reveal that there was a well integrity failure, or leak of gas, after the well had been fracked. There is also additional email correspondence between HSE and DECC which Greenpeace obtained under Freedom of Information legislation in 2015.

The well integrity failure was demonstrated by a 377 psi (2 Mpa) annular pressure anomaly between the intermediate and the production casings (this anomaly is sometimes referred to as the bradenhead pressure). The HSE described this to DECC as 'small'. To give an idea of whether or not this problem is serious, the Colorado Oil and Gas Conservation Commission (COGCC), for example, investigated unconventional gas production and concomitant leaks in the long-contentious Mamm Creek area (Andrews, 2011). Some 2% of the 2867 wells exceeded the level of concern of 150 psi, and remediation was called for in the 12 wells in which bradenhead pressure exceeded 250 psi. So the Preese Hall-1 anomalous pressure of 377 psi should be considered a serious problem. The email record shows that a cement bond log (CBL) of the intermediate (9.625 in) casing had never been run, even though Mr Hill had asked the HSE to require it in 2011. In addition, the CBL that was run on the production casing proved that the cementing was inadequate, and that DECC knew this but tried to hide it.

The operator asserts that "*there have been no leaks to the environment, nor is it believed that there is any prospect of such leaks.*". Its website (as of December 2015) refers only to a groundwater monitoring report dated February 2014, before the leak started. HSE never visited the wellsite during the drilling and testing phases, but only on 30 April 2014, after the integrity failure came to light. The leak has since allegedly been remediated by the operator, by agreement with DECC, and the well was plugged and abandoned. Groundwater monitoring was to continue for one year. The HSE is no longer involved, nor will be in the future. Monitoring of the effectiveness or otherwise of the repair and final plugging rests entirely on what the operator chooses to disclose.

7.5.3 Cuadrilla at Balcombe, Sussex

There were no visits by HSE to Balcombe during drilling. HSE well engineers checked weekly reports from companies on their operations; in other words, self-reporting.

7.5.4 Cuadrilla at Anna's Road, Lancashire

Cuadrilla claims that this site (called Westby by the company) was abandoned due to time constraints and concern for over-wintering birds. It had been drilled to 632 m in 2012. A rather different account has been provided by Mr Mike Hill, who persuaded the then CEO Mark Miller that following the fiasco at Preese Hall-1, cement bond logs (CBLs) should be run on all casing strings of all future wells. Mr Hill would check the CBLs himself on behalf of the public, because HSE had no interest in doing this. At Anna's Road the CBL showed a potential wash-out (the borehole wall crumbling), so the company did a cement job. This was all correct and proper procedure. But on resuming drilling a tool got stuck and the well had to be abandoned. The failure here is that the HSE was not prepared to do its job.

7.6 Summary of the regulatory impunity of operators

On the specific issue of faults in the shale basins, the evidence presented above shows that prospective operators are currently free to:

- Define what they mean by local and regional faults.
- Drill through faults on the way to the target shale.
- Supply misleading examples of seismic data, or none at all.
- Drill vertical wells without even 2D seismic data control.
- Drill horizontal wells blind, with no seismic image as a guide for the drill-bit.
- Drill adjacent to major faults.
- Ignore published geological fault map information.

More generally, they are also able to:

- Start drilling without adequate baseline monitoring studies having first been undertaken.
- Drill sidetrack wells without prior planning permission.
- Persist in fracking even when seismic activity has been triggered.
- Self-regulate; deciding when (or even if) to inform the authorities of problems like deformed well casing or anomalous wellhead pressure.
- Disguise unconventional exploration as conventional.
- Salami-slice exploration/appraisal planning applications so that fracking is postponed for a later planning application.
- Deny that serious problems such as anomalous wellhead pressure may exist.
- Allegedly remediate any well problems, plug and abandon without concurrent or subsequent independent control by regulatory authorities.

7.7 Discussion

7.7.1 Summary

The UK academic societies report discussed in section 5.2 above (Royal Society and Royal Academy of Engineering, 2012) also reviewed UK regulation in some detail, but with some confusion and with a perceptible pro-industry bias; it wrongly stated that LMA planning permission precedes the issue of a permit by the EA; it introduced the irrelevant example of Wytch Farm in asserting that the "*UK has the experience of best practice to draw on*"; it believed that the more wells are drilled, the greater will the "*probability of an instance of a failed well*" - an elementary failure of understanding of statistics (unless it is seeking to imply that safety standards drop as more wells are drilled). The committee recommended that the disparate regulatory bodies be brought under one central overseeing body, but this has not come to pass.

To sum up the process; the OGA issues a PEDL, but then fails to perform adequate checks on the financial or technical integrity of the Developer, or to follow up on potential later problems such as inability of the Developer to fulfil the obligations of the PEDL. Extensions and modifications to PEDLs are granted with little or no legal justification. No sanctions on underperforming Developers are ever applied.

The EA is supposed to scrutinise the environmental aspects of the development proposal, but in practice does not understand the deep geology. In my experience its comments have been limited to shallow groundwater and the surface.

It falls to the County Council (or the relevant minerals planning authority) to consider the application, but it does not have the technical resources to do so adequately. It can and should commission outside expert advice, but this may be biased. Consultation submissions can be ignored. An Officer Report prepared by the council's officers may be biased or inadequate, but planning committee councillors fear for the consequences of defying the recommendations of such a report, in that they may be held personally liable if the Developer challenges a refusal.

There is no requirement for the Developer to publish details of its geological data and interpretations.

Developers are now taking advantage of the inadequate definitions of unconventional exploitation and of fracking (Sections 2 and 3 above, respectively) to declare publicly that they are undertaking conventional hydrocarbon exploration (while on occasion admitting privately to shareholders that their activities are unconventional in nature). The OGA helpfully has defined all the current Weald licences to be for conventional oil.

The HSE is supposed to check on the surface safety aspects of the development, but history demonstrates that the system appears to rely on Developer self-reporting, with inadequate site visits by HSE staff. The HSE has no remit to question the geological aspects of the drilling, only the engineering technical facets.

Only the issue of earthquake triggering has been addressed since the Preese Hall-1 experience, by the introduction of a 'traffic light' system of seismic monitoring during fracking. Baseline groundwater monitoring is now being introduced, but only in an inadequate manner; for example, a few 30 m deep boreholes will never detect pollution problems at 1500 m depth.

In conclusion, it is evident from the case histories summarised above that UK regulation of onshore unconventional exploration is inadequate. Hawkins (2015) describes the current regulatory regime, from a legal perspective, as "*far from satisfactory*".

7.7.2 The necessity of bonds

There is inadequate provision in current regulation to cover ongoing and possibly long-term financial consequences for the public in the event of default by the licensee. An inbuilt provision in new, more robust, legislation should include a mandatory bond to be paid to cover possible future site restitution and loss of amenity such as contamination of a groundwater resource. Planning consent has just been granted for two developments by IGas in Nottinghamshire, subject to payment of such a bond. The sum of £650,000 has been mentioned to cover restitution at each site, but not officially confirmed.

Given the possibility of long-term groundwater contamination arising as a result of UOG activities, a compensatory figure, to be lodged as a bond in the order of millions of pounds is indicated. A bond to cover any and all future pollution incidents and environmental restoration, set at a realistic level (say, of the order of £10M per 10 km x 10 km licence block), and constructed in such a manner that it cannot be defaulted upon by liquidation of the licensee company or transfer of assets and liabilities, should be made a condition of planning consent. Given that the UOG industry claims that such incidents are highly unlikely, there should be no difficulty in underwriting such a bond at Lloyds.

The inadequacy of bonds left by defaulting companies for environmental restoration of open-cast coal mines should serve as a lesson for the Scottish Government. In East Ayrshire, council minutes for 19 September 2013 noted that the costs of restoration of two sites would be £162M, whereas the bonds to be called in amounted to £29M. This and other similar scandals have been documented by George Monbiot.

7.8 Industry influence and lobbying

Here is an example of the hidden hand of industry behind supposedly impartial studies:

The SG commissioned the KPMG report. This cited the:

- EY report 'Getting ready for shale gas', which refers to the:
    - IoD report 2013 'Getting shale gas working', which was:
        - sponsored by Cuadrilla.

First chapter in the IoD report has the bombastic title '*The US shale boom –a trailblazer for the world*', which reveals the pro-industry bias. A more appropriate title for a chapter about the US shale industry, given the evidence I have shown in Sections 6.3 and 6.4, might be '*The US shale bubble - a lesson to be avoided elsewhere*'.

A common refrain in the UK pro-fracking lobby, designed to win over agnostics, is that since we do not know whether or not it will be safe, we have to drill a few wells and try the procedure out. Such test drilling was proposed in Scotland in October 2015 by the former Energy Minister Fergus Ewing. But such an insular view begs the question of whether or not we already have enough information to make a sound evidence-based decision without having to resort to 'home-grown' tests.

The Scottish independent expert review did not have a remit to say whether or not UOG should happen; its remit was to compile scientific evidence. However, it appears to have unwittingly fallen into the 'further work required' trap:

> "*Although further exploratory drilling **will** be required, Scotland’s geology suggests that there could be significant reserves of unconventional oil and gas*" [my emphasis].

The review panel could and should have made appropriate comparisons with the geology and UOG industries (if any) of other countries such as the USA, France and Germany, and then concluded that there is no justification for further experimental drilling. The evidence from the USA, for example, demonstrates the environmental risks and unsound economics of the mature industry (Sections 5 and 6 above). It could have studied the scientific evidence leading to the 2011 ban in France and the now-permanent moratorium in Germany, but it did not. This is a failure on the part of the experts; such in-depth considerations would not have transgressed into the realm of policy, for which it did not have a remit.

There exists the insidious problem of fossil fuel company influence on UK university earth science research. This includes funding for UOG research by way of industrial grants. It is naïve to assume that simply because Dr X, carrying out research funded by oil company Y, declares the research funding, Dr X is thereby exonerated from all suspicion of influence. The problem is examined in Appendix 3, with examples.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 Findings

The definitions of **unconventional oil and gas**, and of **fracking**, as promulgated by the UK government, are misleading, incomplete, and unscientific. I have reviewed the scientific and technical literature to arrive at robust, evidence-based definitions, summarised in section 8.2 below.

UK energy policy goes back to the 2007 white paper, in which UOG was not mentioned. The energy scene has changed so much since 2007 that the white paper is no longer a valid basis for policy. However, UOG is not an 'emerging' form of energy resource.

The arguments for developing an indigenous gas supply by fracking shale are unfounded. The UK can be supplied by a variety of robust sources of pipelined gas and imported LNG. No severe gas supply problems are envisaged over the next decade or so. There is therefore enough time for UK households to switch from gas heating to other heating modes without financial stress.

The UK shale basins are riddled with faults. The reason that very little contamination has occurred from fracked shale, *via* faults, in the USA is that there are almost no faults connecting the deep shale layers to the near-surface groundwater resources.

Contamination from fracked shale can migrate up faults, as demonstrated by six independent modelling studies.

Case histories show that groundwater can circulate from the surface, migrate through shale layers *via* faults, and return to the surface, again *via* faults.

Slickwater fracking fluid contains minute quantities of residual acrylamide. Acrylamide is so toxic that the Maximum Contaminant Level Goal has been set by the US Environment Protection Agency (EPA) at zero. The World Health Organisation has set a guideline value of 0.5 µg/l of acrylamide in water, which it states may be present from the residual levels of acrylamide in the polyacrylamide used to treat drinking water.

No so-called 'test' drilling for UOG exploitation in shale is required in Scotland. We already have enough information from England and overseas to arrive at a scientifically based decision.

The mature (and now senescent) US UOG industry demonstrates that it is financially and environmentally unsustainable. It is a Ponzi scheme, wherein new drilling (to keep up the high initial rate of production) is financed by pulling in new investment in the form of junk bonds. The industry is now collapsing.

The costs of developing a UOG industry in Scotland are admitted by the industry to be likely to be far higher than in the US. The UKOOG, an industry lobby group, stated in October 2013 that:

> "*Reports vary on how the UK shale extraction cost will compare to the US, with some commentators predicting the difference as high as **three times more expensive in the UK.***" [my emphasis].

UOG is often presented as a 'free' resource, just waiting to be extracted. Outlandish estimates are given of how much UOG exists in a particular shale basin, for example in the Weald at Horse Hill, near Gatwick, Surrey, and of how much it is 'worth'. But if the cost of extraction, processing, and distribution exceeds the market value of the good, then the good is worthless. This is likely to be the case with UK UOG.

Hypothetical estimates made by KPMG for the SG of the economic impacts of a Scottish UOG industry are based on an over-optimistic value for the EUR (estimated ultimate recovery) for each well of 3.2 bcf. This figure is over twice the average EUR of US shale gas wells. The economic predictions made by KPMG are therefore worthless. The fundamental error of the KPMG report in this regard is in having relied on a Cuadrilla-sponsored report, instead of the solid evidence from the USGS that I quoted.

Regulation of the nascent UK UOG industry is not up to the job. Almost every development where UOG has started, or is being proposed, presents serious problems. The developers seem to be able to treat the planning system with contempt.

There are few genuinely independent academic earth scientists who can be trusted by the public. The level of debate on the side of the pro-fracking academics (the 'frackademics') is often poor, and they resort to *ad hominem* attacks instead of an engagement in rational debate on facts. One prominent example, whose input to the fracking debate I have discussed elsewhere and in this submission, is Professor Paul Younger of the University of Glasgow. His view of the SG moratorium and the current consultation was reduced to an *ad feminam* attack on the First Minister. He was quoted as saying last year, *à propos* of the moratorium, that Nicola Sturgeon has "*taken flight from reason*". In addition, my view, few of his public scientific contributions to the fracking debate stand up to close scrutiny as I have shown above and elsewhere.

8.2 Recommendations

UOG should be rigorously defined by the following criteria:

- Host rock permeability of <0.1 mD.
- Diffuse or non-defined distribution, in contrast to a conventional trap.
- Requires stimulation to make the fluid flow.

Until a more sophisticated hydrodynamically-based definition of high volume hydraulic fracturing (HVHF) is devised, **the criterion for defining HVHF** based simply on water use should be set at 2500 cu. m for gas and 2000 cu. m for oil.

Based on the evidence I have presented, and using these definitions:

I recommend that the current moratorium on UOG be converted into a permanent ban.

In the event that the Scottish Government does proceed to issue licences for UOG, the following safeguards and precautions must be in place:

- CCS to be up and running to offset greenhouse gas emissions produced by the development.
- Procedures for environmentally sound disposal of *flowback* and *produced* water from the fracking process and the production process, respectively. Disposal into the marine environment (as was proposed by Dart Energy at Airth, discharging into the Forth) is unacceptable.

- The precautionary principle implies that slickwater fracking, using polyacrylamides, should be made illegal, pending the outcome of a great dal more research to demonstrate that it will be diluted to acceptable levels.

- A bond to cover any and all future pollution incidents and environmental restoration, set at a realistic level (say, of the order of £10M per 10 km x 10 km licence block), and constructed in such a manner that it cannot be defaulted upon by liquidation of the licensee company or transfer of assets and liabilities.

- Mandatory semi-high-resolution 3D seismic surveys to be commissioned, interpreted and made open to public inspection prior to drilling consent.

- Inclusion of far more geological and technical detail in proposed planning applications than has been the case hitherto, such that the proposals can be scrutinised independently.

- A mandatory stand-off, or respect, distance of at least 1000 m from the proposed frack volume to any fault.

- Better-defined obligations on the EA (England) and SEPA (Scotland) to scrutinise the deep geological aspects of the proposals.

- The disparate regulatory bodies to be brought under one central overseeing body.

- Real-time seismic monitoring networks to be installed for small earthquake detection AND real-time microseismic monitoring networks to be in place during hydraulic fracturing; BOTH datasets to be made publicly available online in near-real time (i.e. within hours of the events occurring, and as happens already with IRIS, the global seismographic network for earthquakes) for independent scrutiny.

- High volume hydraulic fracturing (HVHF), or fracking for fossil fuel resources, should be defined as the use of 2500 cu. m of water or more per gas well and more than 2000 cu. m per oil well. These criteria separate UOG from fracking in the water or geothermal well contexts.

If these measures make the development of the industry in Scotland uneconomic, then so be it.

APPENDIX 1

SOURCES OF DEFINITIONS OF UNCONVENTIONAL RESOURCES

Schlumberger (major oil services supplier): refers to exploration scale and frequency, economics, porosity and permeability.

Petrowiki (published by Society of Petroleum Engineers, SPE): unconventionals cannot be produced at economic flow rates without assistance of massive stimulation treatments.

Halliburton (major oil services supplier): unconventional reservoirs require assertive recovery solutions.

Canadian Society for Unconventional Resources (CSUR pdf slideshow): slide 7 shows the 0.1 mD divide between unconventional and conventional.

US Department of Energy (DOE): unconventional resources depend on the state of the hydrocarbon, nature of the geologic reservoirs and the types of technologies required to extract the hydrocarbon. Conventional oil and gas deposits have a well-defined areal extent, the reservoirs are porous and permeable, the hydrocarbon is produced easily through a wellbore, and reservoirs generally do not require extensive well stimulation to produce. Unconventional hydrocarbon deposits are very diverse and difficult to characterize overall, but in general are often lower in resource concentration, dispersed over large areas, and require well stimulation or additional extraction or conversion technology.

US Energy Information Administration (EIA) glossary: produced by means that do not meet the criteria for conventional production, which is defined as crude oil and natural gas that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore.

Harris Cander, BP, presentation to American Associaton of Petroleum Geologists (AAPG), 2012: simple definition by BP geologist using both porosity and permeability, with the latter set at 0.1 mD for low porosities.

UK Onshore Oil & Gas (industry trade group): key difference between unconventional and conventional - stimulation required before the hydrocarbon will begin to flow.

Oil & Gas Journal (leading US industry magazine): tight reservoirs require large hydraulic fracture treatment and/or are produced using horizontal wellbores.

Michael Stephenson (Chief Scientist, British Geological Survey) non-technical book *Shale gas and fracking* (Elsevier, 2015), pp 32-33: conventional is a natural system that creates and stores hydrocarbons in limestone or sandstone traps; with unconventional, the shale has not released its gas, so fracking is required. No mention of tight hydrocarbons.

EU research documents prepared for the European Commission: AEA 2012, AMEC 2015, 2016: criteria for distinguishing between CFF and UOG include:

- permeability,
- geological environment,
- discrete vs. gradational boundaries,

- techniques for drilling and stimulation.

AEA 2012. Support to the identification of potential risks for the environment and human health arising from hydrocarbons operations involving hydraulic fracturing in Europe Report for European Commission DG Environment.

Amec Foster Wheeler Environment & Infrastructure UK Limited (AMEC) 2015. Technical Support for the Risk Management of Unconventional Hydrocarbon Extraction Final Report. European Commission DG Environment.

Amec Foster Wheeler Environment & Infrastructure UK Limited (AMEC) 2016. Study on the assessment and management of environmental impacts and risks resulting from the exploration and production of hydrocarbons Final Report. European Commission.

Gallegos, T. J., B. A. Varela, S. S. Haines, and M. A. Engle 2015. Hydraulic fracturing water use variability in the United States and potential environmental implications, *Water Resour. Res.*, 51, 5839–5845, doi:10.1002/2015WR017278.

Gilfillan, S. and Haszeldine, S. 2016. What's in a name: The risks from re-defining fracking. Energy and Carbon Blog.

APPENDIX 2
Aide-mémoire for the APPG on marine dumping of wastewater

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15 February 2017
[colour diagram improved 30 May 2017]

1 Introduction

Professor Ernie Rutter, who was the geologist on the Shale Task Force, told me last year that marine dumping was being considered as an option for flowback/produced water (hereinafter 'wastewater') from fracking. This aide-mémoire is intended to inform the APPG of the likely legal limitations of such an approach, were it to be adopted.

2 The London Protocol on marine dumping

Here are some extracts from the International Maritime Organisation's web page (http://www.imo.org/en/About/Conventions/ListOfConventions/Pages/Convention-on-the-Prevention-of-Marine-Pollution-by-Dumping-of-Wastes-and-Other-Matter.aspx):

> **Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter Adoption: 13 November 1972; Entry into force: 30 August 1975; 1996 Protocol: Adoption: 7 November 1996; Entry into force: 24 March 2006**
> ...
>
> "Dumping" has been defined as the deliberate disposal at sea of wastes or other matter from vessels, aircraft, platforms or other man-made structures, as well as the deliberate disposal of these vessels or platforms themselves. Annexes list wastes which cannot be dumped and others for which a special dumping permit is required.
> ...
>
> In 1996, Parties adopted a Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972 (known as the **London Protocol**) which entered into force in 2006.
>
> The Protocol, which is meant to eventually replace the 1972 Convention, represents a major change of approach to the question of how to regulate the use of the sea as a depository for waste materials. Rather than stating which materials may not be dumped, it prohibits all dumping, except for possibly acceptable wastes on the so-called "reverse list", contained in an annex to the Protocol.
>
> The London Protocol stresses the “precautionary approach”, which requires that “appropriate preventative measures are taken when there is reason to believe that wastes or other matter introduced into the marine environment are likely to cause harm even when there is no conclusive evidence to prove a causal relation between inputs and their effects”.
>
> It also states that "the polluter should, in principle, bear the cost of pollution" and emphasizes that Contracting Parties should ensure that the Protocol should not simply result in pollution being transferred from one part of the environment to another.
>
> The 1996 Protocol restricts all dumping except for a permitted list (which still require permits).
>
> Article 4 states that Contracting Parties "shall prohibit the dumping of any wastes or other matter with the exception of those listed in Annex 1."

Here are the relevant extracts from the 1996 Protocol, as amended 2006:

ANNEX 1

WASTES OR OTHER MATTER THAT MAY BE CONSIDERED FOR DUMPING

1 The following wastes or other matter are those that may be considered for dumping being mindful of the Objectives and General Obligations of this Protocol set out in articles 2 and 3:

.1 dredged material;
.2 sewage sludge;
.3 fish waste, or material resulting from industrial fish processing operations;
.4 vessels and platforms or other man-made structures at sea;
.5 inert, inorganic geological material;
.6 organic material of natural origin;
.7 bulky items primarily comprising iron, steel, concrete and similarly unharmful materials for which the concern is physical impact, and limited to those circumstances where such wastes are generated at locations, such as small islands with isolated communities, having no practicable access to disposal options other than dumping; and
.8 Carbon dioxide streams from carbon dioxide capture processes for sequestration.

...

3 Notwithstanding the above, materials listed in paragraphs 1.1 to **1.8** containing levels of radioactivity greater than *de minimis* (exempt) concentrations as defined by the IAEA and adopted by Contracting Parties, shall not be considered eligible for dumping; provided further that within 25 years of 20 February 1994, and at each 25 year interval thereafter, Contracting Parties shall complete a scientific study relating to all radioactive wastes and other radioactive matter other than high level wastes or matter, taking into account such other factors as Contracting Parties consider appropriate and shall review the prohibition on dumping of such substances in accordance with the procedures set forth in article 22.

...

ANNEX 2

ASSESSMENT OF WASTES OR OTHER MATTER THAT MAY BE CONSIDERED FOR DUMPING

GENERAL

1 The acceptance of dumping under certain circumstances shall not remove the obligations under this Annex to make further attempts to reduce the necessity for dumping.

WASTE PREVENTION AUDIT

2 The initial stages in assessing alternatives to dumping should, as appropriate, include an evaluation of:

.1 types, amounts and relative hazard of wastes generated;
.2 details of the production process and the sources of wastes within that process; and
.3 feasibility of the following waste reduction/prevention techniques:

.1 product reformulation;
.2 clean production technologies;
.3 process modification;
.4 input substitution; and
.5 on-site, closed-loop recycling.

…

CONSIDERATION OF WASTE MANAGEMENT OPTIONS

5 Applications to dump wastes or other matter shall demonstrate that appropriate consideration has been given to the following hierarchy of waste management options, which implies an order of increasing environmental impact:

.1 re-use;
.2 off-site recycling;
.3 destruction of hazardous constituents;
.4 treatment to reduce or remove the hazardous constituents; and
.5 disposal on land, into air and in water.

...

CHEMICAL, PHYSICAL AND BIOLOGICAL PROPERTIES

7 A detailed description and characterization of the waste is an essential precondition for the consideration of alternatives and the basis for a decision as to whether a waste may be dumped. If a waste is so poorly characterized that proper assessment cannot be made of its potential impacts on human health and the environment, that waste shall not be dumped.

8 Characterization of the wastes and their constituents shall take into account:

.1 origin, total amount, form and average composition;
.2 properties: physical, chemical, biochemical and biological;
.3 toxicity;
.4 persistence: physical, chemical and biological; and
.5 accumulation and biotransformation in biological materials or sediments.

3 IAEA determination of suitability for disposal at sea

Wastewater cannot be exempted under the terms of para. 1.5 of Annex 1 quoted above ("*inert, inorganic geological material*") because such water contains NORM (i.e. it is not inert). If the waste is above the *de minimis* (exempt) level then it cannot be dumped at sea. The issue then is whether the waste falls below the *de minimis* levels for disposal, which are defined by the IAEA (Annex 1, para. 3, above).

The IAEA first considered this problem in 1979 (IAEA 1981), and issued a procedure for the assessment of such waste in 2003 (IAEA 2003). The guidance is provided in Annex 1 to this latter document. Firstly, it would appear that the wastewater does not fulfil the automatic exemption criteria (Annex 1, para. 3.5). It therefore requires specific assessment. Here is a summary of the stepwise evaluation procedure as it would be applied to wastewater (IAEA 2003, pp.51-54).

Step 1. Wastewater will be eligible for dumping if and only if it falls below the *de minimis* level.
Step 2. Since wastewater is a *modified* material, i.e. it is the water extracted from shale along with the hydrocarbons, and is not 'virgin' natural shale, we go to Step 3.
Step 3. The cause of the modification is assessed; in the case of wastewater this is due to the second cause: "*human activities that increase the concentrations of natural radionuclides in candidate materials*". So we go to Step 5.
Step 5. This assessment concerns whether the UK national radiation protection authority has previously assessed and cleared or exempted the wastewater for dumping, taking into account marine environmental pathways. The answer here is No, so we proceed to Step 6.
Step 6. Since wastewater has not passed the *de minimis* criteria under Steps 1-5, a *specific assessment* is required.

Unfortunately Appendix 2 of IAEA (2003), dealing with the assessment of dose resulting from the dumping process assumes that the material is a ship-borne dry load. This clearly does not apply to wastewater, which I assume would be disposed of *via* a pipeline. So much of the assessment procedure is irrelevant; only the dose to the public resulting from exposure to seafood and contaminated sediments, by external or internal radiation (table II.III, p. 40; table II.VII, p. 42) would appear to be applicable.

The assessment would need to be made for each type of wastewater from the various sources envisaged. The assessment of NORM for the purposes of determining whether the wastewater passes under the *de minimis* limit does not, of course, preclude the need to assess the environmental impact of the other toxic components of the wastewater.

4 Definition of 'sea'

The 'sea' is defined, for the purposes of the London Protocol, to be the part of the sea lying seaward of the baseline by which a state measures its territorial waters. The baseline is normally the low water mark or datum, defined by the lowest astronomical tide. In addition, 'straight lines' are used to define the baseline across bays, and to help simplify the definition of the territorial sea.

In the UK baseline definition (Order in Council, 25 September 1964), there is an extensive set of straight lines enclosing the Hebrides from Cape Wrath to the Mull of Kintyre, and bay closing lines for the following bays:

West coast
- a) Firth of Clyde
- b) Solway Firth including Luce and Wigtown Bays
- c) Morecambe Bay
- d) Tremadoc Bay
- e) Bristol Channel including Carmarthen Bay Britain);

East coast
- f) The Thames Estuary
- g) The Wash
- h) The Humber Estuary
- i) Firth of Forth
- j) Firth of Tay
- k) Moray Firth

Northern Ireland
- l) Belfast Lough

The Hebridean baseline is defined by a schedule of 26 latitude/longitide coordinates, whereas the bay closing lines listed above are indicated on a chart provided by the Hydrographer.

The London Protocol on the prevention of marine dumping applies to all sea lying seaward of the baseline, and is not to be confused with the nation's territorial limits, which lie 12 nautical miles further out (Figure1 below). However, if the dumping is to take place within the baseline defined above the London Protocol will not apply.

So the London Protocol does not apply to internal waters, but does apply to all waters seaward of the baseline. By way of example, consider a hypothetical wastewater treatment and disposal facility at Bran Sands, on Teesside. The wastewater could be dumped into the River Tees, to the west, and be exempt from the London Protocol, but a pipeline running north-east out to sea at Coatham Sands would have to comply with the protocol.

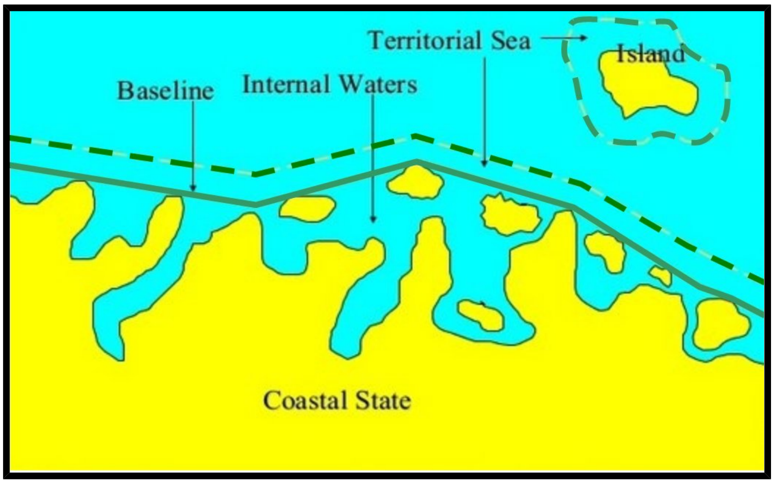

Figure 1. Hypothetical example of straight baselines.

5 Discharges from pipelines into internal waters

My understanding of this topic comes from a review by Hunt (2004), who states that the principles for release of waste *via* pipelines was reviewed by the IAEA (2000). Pipeline discharge is not explicitly mentioned in the cited IAEA document, which does, however, state that discharges "*directly to surface water bodies*" are considered in the report. The report states:

> 1.7. An additional principle of the Waste Safety Fundamentals is that radioactive waste be managed in such a way as to provide an acceptable level of protection of the environment. This includes the protection of living organisms other than humans and also the protection of natural resources, including land, forests, water and raw materials, together with a consideration of non-radiological environmental impacts. This Safety Guide is concerned only with control measures to protect human health.

The report gives guidance in Section 3 for setting discharge limits for new sources; clearly, discharge of wastewater is a new source as far as the UK is concerned. The environmental impacts of the wider environment, and not just humans, will have to be assessed, as stated in the quoted paragraph above.

Lastly, if discharge of wastewater into internal waters is envisaged (see Figure 1 above), consideration may also have to be given to the resulting discharge into the sea (Section 4 above). For example, in the case of a possible treatment plant at Bran Sands, discharging into the River Tees, an assessment would have to be made of the resulting downstream discharge into the sea, which falls under the London Protocol.

References

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IAEA 2003. *Determining the suitability of materials for disposal at sea under the London Convention 1972: A radiological assessment procedure.* IAEA Tecdoc-1375. International Atomic Energy Agency, Vienna.

Appendix: Brief CV

Professor Smythe has 45 years of professional experience in applied geophysics, first at the British Geological Survey, then as Chair of Geophysics at the University of Glasgow, followed by consulting for the oil industry. His research interests and experience relevant to the wastewater problem include:

- Adviser to Department of Energy and F&CO on Law of the Sea (1984-85)
- Geological disposal of nuclear waste
- Radiation dose in relation to nuclear accidents
- Economics of unconventional energy exploration

[e n d o f A p p e n d i x 2]

APPENDIX 3

INDUSTRY INFLUENCE ON ACADEMIC RESEARCHERS

Introduction

There are few, if any, genuinely independent academic earth scientists who can be trusted by the public. The level of debate on the side of the pro-fracking academics (the 'frackademics') is often poor. I have been the subject of vitriolic and defamatory attacks by several UK earth scientists who disagree with my view on fracking.

Here is a summary of possible influence case histories.

Possible industry influence at the University of Glasgow

It is an unfortunate coincidence that two researchers who have written papers and other presentations on fracking since 2014 are both at my former institution, the University of Glasgow. One of these two, Professor Paul Younger, holds a senior position and was elected to the University Court in August 2014. They do not (or did not) seem to be aware that I am a lifelong member of the College of Science and Engineering, by virtue of the terms of my retiral agreement of November 1998.

On 1 July 2014 Professor Younger wrote me an outrageous email criticising an interview that he heard me make on BBC Radio Scotland 'Morning Call'. He copied this defamatory email to the BBC. I received a letter from the University Court dated 16 July 2014, which the senior staff refer to as the 'cease-and-desist letter', asking me to stop using my university affiliation. I refused to do so, since I have the right in perpetuity. Younger also revealed the reason why he wanted me silenced. In an internal email dated 23 July 2014 entitled 'Misrepresenting the University of Glasgow' he wrote:

> "*Various industrial research partners have suggested an open letter to major newspapers making clear he does not speak for us.*"

In effect, he is arguing for, or assuming that there is, a corporate view to be taken by the university on the subject of fracking (i.e. his view), and that I should not be permitted to express contrary views.

Professor Younger was quoted in the national press in August 2014 calling me a fraud and a liar, because I had claimed that I was a Chartered Geologist in my two submissions to the Falkirk Planning Inquiry Appeal of 2014. In fact I had written in my CV for these submissions that my qualifications included being a Chartered Geologist. The exact phrasing is "*My professional qualifications are: BSc Geology (Glasgow 1970), PhD Geophysics (Glasgow 1987), Chartered Geologist.*" This is correct in that I was made a CGeol in 1991, but stopped paying the necessary fees in 1995. After that date I never used the appellation CGeol after my name. So it is a moot point as to whether Younger was even technically correct, in saying that I was wrongly claiming still to be a CGeol in 2014. It is noteworthy that he has never sought to question the scientific content of my two submissions.

Dr Rob Westaway, a colleague of Younger at Glasgow, wrote to the editorial office of *Solid Earth* on 29 January 2016, as follows:

> *"I see that you published a paper two days ago ... Its author is a controversial character who has not worked in any university for almost twenty years. As a result, he is out of touch with the subject area and, thus, makes a lot of mistakes;*

from what I have read so far, this latest contribution of his is no exception. It is also unfortunate that he continues to claim an affiliation to the University of Glasgow even though he has not worked here, as I say, for almost twenty years."

This comment is defamatory, as well as being factually incorrect. I do not have to be employed by the university to claim my affiliation, which was granted along with my Emeritus status on my retiral in 1998, both in perpetuity.

In February 2016 Westaway inserted a citation, 'Seamark 2014' purportedly as a scientific reference, in one of his comments on my 2016 *Solid Earth Discussions* paper. But the reference is to the *Daily Mail* article in which Younger had defamed me in August 2014. The journal editor asked Westaway to remove the reference, which he did, but he then re-inserted it in a subsequent comment. Westaway had also criticised the journal for permitting my discussion paper to appear in the first place. Westaway's actions resulted in a comment and admonition by the Editor-in-Chief. Such behaviour has never been seen before, to my knowledge, in an earth science journal.

In August 2014 Dr Westaway started correspondence with Cuadrilla, initially about Cuadrilla's horizontal well at Balcombe. The Glasgow-Cuadrilla correspondence continued through October 2014. On 13 October Lancashire County Council wrote to Professor Younger asking him to comment on my LCC submissions of the previous month concerning Cuadrilla's applications to drill at Preston New Road and Roseacre Wood.

It was reasonable of LCC to seek outside advice on what are highly technical matters, but the question to be asked is, why did LCC ask the Glasgow researchers, when they are only two out of possibly several dozen UK academic earth scientists with hydrocarbon exploration research interests? I can only surmise that Cuadrilla put the names of Younger and Westaway forward to LCC. I further surmise that because of Younger's comments about me in the national press, Cuadrilla thought that Younger might well write an antagonistic review. Younger and Westaway duly submitted their report to LCC in December 2014, but it was not made public until the following summer. In the meantime they had written to LCC, requesting that some of it be retracted.

The correspondence between Glasgow and Cuadrilla continued intermittently through 2014 and into 2015, culminating in two Cuadrilla staff flying to Glasgow for a meeting on 9 June 2015.

The LCC Officer Report was published on 15 June, marginalising and denigrating the expert evidence of myself and others (see section 7.4 above). The question arises out of the private Glasgow-Cuadrilla contacts and association; were the two Glasgow researchers in effect working to promote Cuadrilla? Were they seeking research funding? In any event, no such funding has materialised.

Internal University emails from 2015-2017 show that Professor Younger continued his campaign against me within the University. This culminated in my university email address and remote access rights being withdrawn without warning or explanation on 30 January 2016. This outrageous action by the university is clearly a response to the fact that I had just published the discussion paper in *Earth Science Discussions*. It is an attempt to silence me bcause certain current employees at Glasgow do not agree with my views on fracking.

After many months of fruitless negociations, my lawyer in Glasgow has just submitted an Initial Writ to the Scottish Courts demanding that the University either restore my access rights or pay me substantial compensation.

This whole episode brings my *alma mater* into disrepute, and illustrates the pervasive and malign influence that fossil fuel companies can have on universities.

Dr James Verdon, University of Bristol

He is an earth scientist who took up a post-doctoral position at Bristol in 2011. His initial research involved setting up a microseismic monitoring station at Balcombe for Cuadrilla, funded by an industry consortium.

He runs a personal blog site, Frack-Land (not to be confused with my Frackland), in which he was quick to attack me in a blog dated 1 August 2014. He repeated the libels that Paul Younger had made in the national press. He also permitted without moderation two anonymous comments making further defamatory comments. One of these comments, from an alleged Glasgow geology graduate, criticised my supposed poor teaching skills, but the comment is nonsensical because he/she refers to a class I never taught. The fact that Verdon's and his anonymous commenters are still online reflects badly on Verdon.

Professor Rebecca Lunn, University of Strathclyde

I am slightly familiar with Professor Lunn, an engineer, from the field of nuclear waste disposal. However, *The Times Scotland* (paywalled) reported on 14 March 2015 her venture into fracking:

> "*Rebecca Lunn, of the University of Strathclyde, who was named this week as one of ten outstanding women in Scotland, said that the government had ignored advice from scientific institutions as well as its own working group by declaring a moratorium on fracking, despite evidence that, if properly regulated, it posed little environmental risk. "It's an extremely ill-informed debate," she said. "They've been fracking in the US for 50 years, and until recently nobody noticed.".*
>
> "*I don't think it's an issue," she said. "There have been issues in the US, but not to do with the fracking itself — they have been caused by poor regulation. There are some instances where there has been pollution of surface water aquifers, but they are associated with things like unlined wells. As to causing earthquakes, it's not scientifically possible."* "

Note here the repetition of old canard about fracking not being novel. Evidently she takes the same view as Professor Younger on the SG moratorium. Unless she has been grossly misreported, it seems astonishing that she thinks that fracking cannot cause earthquakes (it does, but they are minor). Furthermore, as a civil and environmental engineering specialist, it seems incrdible that she attributes the now widely-documented contamination events in the USA to 'unlined' wells.

I am also concerned about her grasp of basic geology in her supposed area of expertise, geological disposal of nuclear waste. This field has many similarities, geologically, to the fracking contamination problem. She was a panel member of the supposedly independent Committee for Radioactive Waste Management (CoRWM). In a public lecture at the Geological Society of London on this topic she misled over the level of Cumbrian support for new siting policy. The published version of the lecture had to be amended as a result. She also criticised me in an *ad hominem* manner for my views on disposal of nuclear waste in West Cumbria. Figure 1 illustrates both her methodology of attack and at the same time her ignorance of the geology.

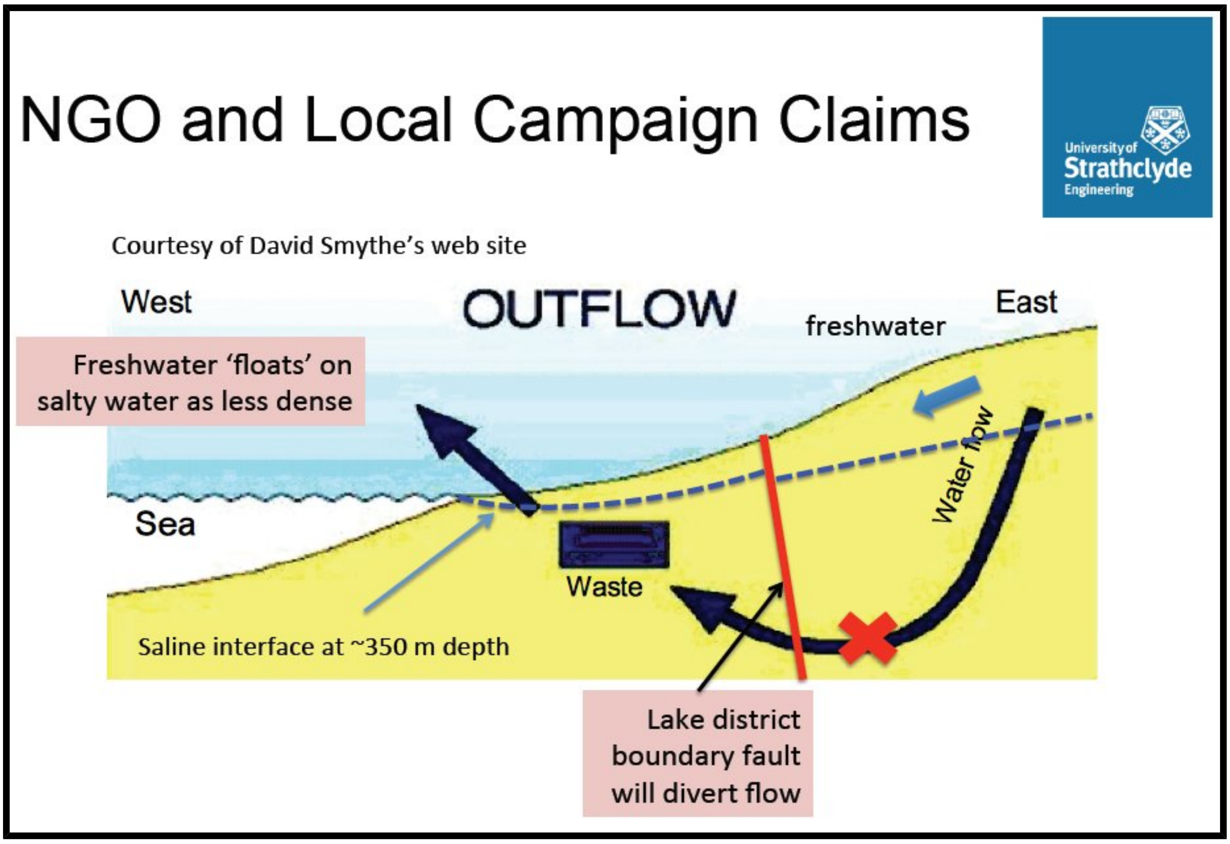

Figure 1. Hydrogeological flow through a conceptual waste repository in West Cumbria, according to Professor Lunn.

Firstly she takes a highly simplified early diagram of mine, intended for a non-technical public. Then she adds her own spin. The additions have several errors:

- The Lake District Boundary Fault cannot appear in this cartoon, as it is far too far to the east.
- The hade (dip direction) and sense of throw are both wrong.

She has probably confused her marked fault with those bounding the waste repository, in which case the fault should be positioned against the east side of the repository, and does indeed divert the flow - from the repository! - upwards, as shown by the thick black arrows on the original cartoon. Such flow was modelled by Professor Haszeldine's group, then at Glasgow University, in 1999. It appears that Professor Lunn is unaware of this research. Incidentally, the cartoon of 2009 was borrowed from Professor Haszeldine.

In conclusion, if Professor Lunn wished to engage with my work on nuclear waste disposal she should have studied in depth the many technical submissions I have made to government on the subject over twenty years. Her sloppy and needlessly *ad hominem* approach will not be appropriate, should she start to undertake any serious research in fracking.

ReFINE shale research group

Davies and Herringshaw of ReFINE (Researching Fracking In Europe), a research consortium led by Newcastle University and Durham University in the UK, published a short paper in 2015 on how fracking research should be funded. They point out how the group's funding has to be transparent. Funders have 45 days before a paper is published to comment upon it. One of the funders, Total, withdrew from the consortium shortly after the group published a paper on well integrity in 2014 The reason for the withdrawal by Total was not stated. It is possible that it was because the company did not like the outcome of the research. If so, this could be a classic instance of a project funder trying to influence the research outcome, and it is to the credit of Professor Richard Davies and his research group that they resisted such an attempt.