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Hydraulic Fracturing: A review of theory and field experience

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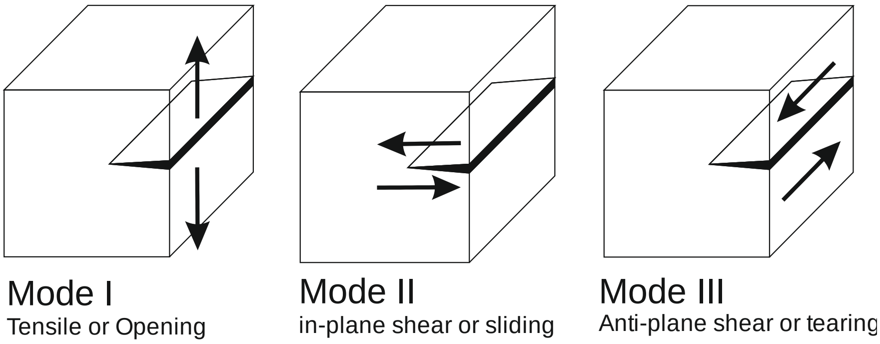

BRITISH GEOLOGICAL SURVEY

ENERGY & Marine Geoscience PROGRAMME

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Hydraulic Fracturing: A review of theory and field experience

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Schematic representation of the three fundamental modes of discontinuity displacement

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M4ShaleGas - Measuring, monitoring, mitigating managing the environmental impact of shale gas

HYDRAULIC FRACTURING:
A REVIEW OF THEORY AND FIELD EXPERIENCE

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Public introduction

M4ShaleGas stands for *Measuring, monitoring, mitigating and managing the environmental impact of shale gas* and is funded by the *European Union's Horizon 2020 Research and Innovation Programme*. The main goal of the M4ShaleGas project is to study and evaluate potential risks and impacts of shale gas exploration and exploitation. The focus lies on four main areas of potential impact: the subsurface, the surface, the atmosphere, and social impacts.

The European Commission's Energy Roadmap 2050 identifies gas as a critical fuel for the transformation of the energy system in the direction of lower CO_2 emissions and more renewable energy. Shale gas may contribute to this transformation.

Shale gas is – by definition – a natural gas found trapped in shale, a fine grained sedimentary rock composed of mud. There are several concerns related to shale gas exploration and production, many of them being associated with hydraulic fracturing operations that are performed to stimulate gas flow in the shales. Potential risks and concerns include for example the fate of chemical compounds in the used hydraulic fracturing and drilling fluids and their potential impact on shallow ground water. The fracturing process may also induce small magnitude earthquakes. There is also an ongoing debate on greenhouse gas emissions of shale gas (CO_2 and methane) and its energy efficiency compared to other energy sources
There is a strong need for a better European knowledge base on shale gas operations and their environmental impacts particularly, if shale gas shall play a role in Europe's energy mix in the coming decennia. M4ShaleGas' main goal is to build such a knowledge base, including an inventory of best practices that minimise risks and impacts of shale gas exploration and production in Europe, as well as best practices for public engagement.

The M4ShaleGas project is carried out by 18 European research institutions and is coordinated by TNO-Netherlands Organization for Applied Scientific Research.

Executive Report Summary

This report summarises the current state-of-the-art knowledge of the hydraulic fracturing process used by the shale gas/oil industry using open peer-reviewed literature and from government commissioned research reports. This report has been written to make statements on our knowledge of the following questions:

- *How do hydrofractures form?*
- *How far do hydrofractures extend during stimulation?*
- *What dictates where hydrofractures propagate?*
- *How do hydrofractures interact with the existing fracture network?*
- *Can the size and distribution of hydrofractures be controlled?*

Gaps in our knowledge have been highlighted, with the largest of these resulting from differences between North American and European shale rocks.

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1 INTRODUCTION

1.1 Context of M4ShaleGas

Shale gas source rocks are widely distributed around the world and many countries have now started to investigate their shale gas potential. Some argue that shale gas has already proved to be a game changer in the U.S. energy market (EIA 2015[1]). The European Commission's Energy Roadmap 2050 identifies gas as a critical energy source for the transformation of the energy system to a system with lower CO_2 emissions that combines gas with increasing contributions of renewable energy and increasing energy efficiency. It may be argued that in Europe, natural gas replacing coal and oil will contribute to emissions reduction on the short and medium terms.

There are, however, several concerns related to shale gas exploration and production, many of them being associated with the process of hydraulic fracturing. There is also a debate on the greenhouse gas emissions of shale gas (CO_2 and methane) and its energy return on investment compared to other energy sources. Questions are raised about the specific environmental footprint of shale gas in Europe as a whole as well as in individual Member States. Shale gas basins are unevenly distributed among the European Member States and are not restricted within national borders, which makes close cooperation between the involved Member States essential. There is relatively little knowledge on the footprint in regions with a variety of geological and geopolitical settings as are present in Europe. Concerns and risks are clustered in the following four areas: subsurface, surface, atmosphere and society. As the European continent is densely populated, it is most certainly of vital importance to understand public perceptions of shale gas and for European publics to be fully engaged in the debate about its potential development.

Accordingly, Europe has a strong need for a comprehensive knowledge base on potential environmental, societal and economic consequences of shale gas exploration and exploitation. Knowledge needs to be science-based, needs to be developed by research institutes with a strong track record in shale gas studies, and needs to cover the different attitudes and approaches to shale gas exploration and exploitation in Europe. The M4ShaleGas project is seeking to provide such a scientific knowledge base, integrating the scientific outcome of 18 research institutes across Europe. It addresses the issues raised in the Horizon 2020 call LCE 16 – 2014 on *Understanding, preventing and mitigating the potential environmental risks and impacts of shale gas exploration and exploitation.*

[1] EIA (2015). Annual Energy Outlook 2015 with projections to 2040. U.S. Energy Information Administration (*www.eia.gov*).

1.2 Study objectives for this report

This report has been produced as a state-of-the-art review of our current knowledge of hydraulic fracturing as part of Work Package 1 of the European Commission M4ShaleGas project. The general objective of the M4ShaleGas program is to provide scientific recommendations for minimizing the environmental footprint of shale gas exploration and exploitation in Europe. The objective of this report is to summarize our current state-of-the-art understanding of the hydraulic fracturing operations of shale gas exploration and production companies.

1.3 Aims of this report

This report has been written from the open peer-reviewed literature and from government commissioned research reports as a statement of our current knowledge. However, considerable information has been acquired from industry conference proceedings. The rate of publication on topics related to the extraction of shale gas is high at present and every care has been taken to include as many of the key publications as possible. This report has been written to make statements on our knowledge of the following questions:

- How do hydrofractures form?
- How far do hydrofractures extend during stimulation?
- What dictates where hydrofractures propagate?
- How do hydrofractures interact with the existing fracture network?
- Can the size and distribution of hydrofractures be controlled?

No other aspect of hydro-fracturing is considered.

1.4 M4ShaleGas

Knowledge of the environmental footprint from shale gas exploration and exploitation mainly come from US and Canadian experiences. Shale gas development in Europe may benefit from lessons learned in the US. However, population densities, geological settings, and regulations in some areas of European Union Member States are markedly different from those in the US and Canada.

Within the M4ShaleGas project four key gaps in our knowledge related to the potential environmental risks and impacts of shale gas exploration and exploitation will be addressed, as identified from consultations with different stakeholders (i.e. public, regulators, governments and industry). These key gaps are:

(1) the need for a research-based understanding of differences between Europe, US and Canada resulting from differences in their geological and geopolitical settings;
(2) the need for quantitative risk assessment and mitigation of risks and impacts that are specific for Europe;

(3) lack of knowledge on the applicability of US and Canadian best practices to Europe; and
(4) insufficient research-based knowledge on public perceptions of risks and impacts in Europe.

The structure of the M4ShaleGas program is based on the main areas of potential impact:

WP1 **Subsurface**; Impact of subsurface activities: Hydraulic fracturing, induced seismicity and well integrity;
WP2 **Surface**; Impact of surface activities: Water, soil and well site activities;
WP3 **Atmosphere and climate**; Impact on air quality and global climate;
WP4 **Society**; Public Perceptions of the Environmental Impacts; and
WP5 **Integration, stakeholder engagement and dissemination**.

The specific objectives of each Work Package will focus on:

- **Measuring** the environmental impact of shale gas exploration and exploitation in Europe
- **Monitoring** the environmental impact of shale gas exploration and exploitation in Europe
- **Mitigating** the environmental impact of shale gas exploration and exploitation in Europe
- **Managing** the environmental impact of shale gas exploration and exploitation in Europe

Measurements, monitoring, mitigation and management relates to environmental risks and impacts as well as public perceptions on risks and impacts.

1.5 WP1: Subsurface

Work Package 1 of the M4ShaleGas project is targeted at the impact of subsurface activities; including hydraulic fracturing, induced seismicity and well integrity. Within the work-package there are five areas of research:

WP1.1 the subsurface impact of hydraulic fracturing;
WP1.2 risks of reactivating natural faults and inducing damaging seismicity;
WP1.3 seismic monitoring of hydraulic fracturing and gas production;
WP1.4 risks of leakage along wellbores; and
WP1.5 drilling hazards and well integrity.

A sixth sub-package task (WP1.6) will integrate the findings from WP1.1 – 1.5.

1.6 WP1.1: The subsurface impact of hydraulic fracturing

The main objectives of this sub work package are to quantify the impact and scale of hydraulic fracturing in the subsurface, and provide recommendations to minimise the subsurface impact of hydraulic fracturing. The work package will address the following main topics:

- Propagation mechanisms of hydraulic fractures, extent of stimulated reservoir volume, subsurface influence of operations.
- Analysis and mitigation measures for leakage risks along fractures, potentially allowing contamination of shallow groundwater.
- Knowledge transfer from ongoing hydraulic fracturing and gas migration experiments, and upscaling from lab- to field-scale.
- Numerical simulations of hydraulic fracturing to analyse the variation and uncertainty in fracture propagation and extent of the stimulated reservoir volume.

Understanding the potential extent of fractures arising from wellbore stimulation allows an estimate of the likely extent of subsurface influence of shale gas extraction (the fractured disturbed zone or stimulated reservoir volume) to be made. Fracture networks will be investigated by a staged approach, involving a combination of scientific review with limited laboratory experimentation and upfront predictive modelling. Insight will be gained into the potential for fractures to propagate between shale targets and neighbouring rock formations adjacent to the wellbore. Numerical simulations of hydraulic fracturing will be performed to make upfront analysis of variation and uncertainty in fracture propagation and extent of the stimulated reservoir volume. This will inform discussions and other Work Packages' within the M4ShaleGas project that are concerned with the potential for man-made pathways to be created between shales and surface and subsurface receptors, such as shallow aquifers used for drinking water supply.

1.7 Structure of the report

This report represents a literature review of the current state-of-the-art knowledge on hydraulic fracturing during shale gas operations. It is made up of eight chapters:

- **Chapter 1: Introduction:** This chapter outlines the M4ShaleGas project and the aims and objectives of the current study;

- **Chapter 2: Hydraulic fracturing:** This chapter outlines how hydraulic fracturing is conducted by the industry. These are important considerations when performing laboratory experiments or numerical analysis of the process of hydrofracturing;

- **Chapter 3: Shale variability:** This chapter briefly outlines the considerable variability seen in shale units in terms of sedimentology, organic content, gas content, and strength properties;

- **Chapter 4: Fracture initiation:** This chapter introduces the mechanisms responsible for the formation and initiation of hydraulic fractures following perforation of the well casing;

- **Chapter 5: Fracture propagation:** This chapter outlines how far hydraulic fractures will extend in the sub-surface and the appearance of the hydrofractures;

- **Chapter 6: Induced vs natural fractures:** This chapter examines the inter-play of the pre-existing fracture network found in natural shale units and the induced hydrofractures created during hydraulic fracturing;

- **Chapter 7: Engineering considerations:** This chapter discusses the engineering considerations introduced in Chapter 2 and how these can dictate the extent of the fracture zone and/or the yield from a shale gas play;

- **Chapter 8: Knowledge gaps:** This chapter summarises all the knowledge gaps identified within the previous chapters and makes recommendations on how we may increase our understanding of the shale gas system.

2 HYDRAULIC FRACTURING

This chapter describes the relevant stages of the hydraulic fracturing process. Several overviews of hydraulic fracturing are available in the literature; including API, 2009; Arthur *et al.*, 2008; Broomfield & Donovan, 2012; CSUG, 2010; King, 2012; Mair *et al.*, 2012; Reinicke *et al.*, 2010; US EPA, 2010; etc. Hydraulic fracturing is the process by which a liquid under pressure causes a geological formation to crack open. The process is also known as 'HF', 'fracking' or 'fracing', but is referred to as 'hydraulic fracturing' in this report. In order to be able to understand the mechanical controls on hydraulic fracturing it is important to have a detailed knowledge on the injection process itself. This allows us to pinpoint areas of the process which are less well understood and where research should be focused. An increase in research into these areas will ultimately result in the process becoming more refined and lead to either higher productivity or a more cost effective process and reduce the likelihood of environmental contamination.

2.1 Depth of interest

The first consideration in assessing the hydraulic fracturing process is the depth range that it is likely to occur. Andrews (2013) state that productive shale gas tends to occur at depths greater than 1,000 metres. This figure comes from Charpentier & Cook (2011) who state that whilst gas is found at shallower depths, the lower pressure experienced results in low flow rates. The Geological Society of London states that most shale gas plays occur in the depth range of 2,000 to 5,000 metres (Geol. Soc., 2013) and that depths should be typically less than 3,500 metres (Geol. Soc., 2011). Fisher & Warpinski (2012) report hydraulic fracturing data for the United States. This shows that existing operations have occurred between 4,500 ft and 14,000 ft in Woodford shale, 4,500 ft to 9,000 ft in Marcellus, and 3,000 ft to 13,000 ft in Eagle Ford. This gives a total depth range of 1,000 to 4,300 metres. The Energy Information Administration (US) reports a maximum depth of hydraulic fracturing of 5,000 metres (US EIA, 2013). Therefore, it is expected that shale gas exploitation in Europe will be limited to the 1,000 to 5,000 metre depth range.

2.2 State of stress

Knowing the depth range that hydraulic fracturing is bound allows an estimate to be made of the expected stresses experienced by shale at depth. The magnitude and direction of the principal stresses are important in hydraulic fracturing because they control the amount of pressure required to create and propagate a crack, the direction of the crack, and the crack shape. The stress a rock experiences is dictated by the weight of the overlying rock, with additional stresses created by tectonic movements. Generally, in sedimentary sequences a total vertical principal stress gradient of 23 MPa/km can be assumed (Zoback, 2010). This suggests that total vertical stress (σ_V) is likely to range between 23 and 115 MPa in European shale gas operations. As well as a vertical stress component, shale at depth will be subject to horizontal stresses. Zoback (2010) reports that the minimum horizontal stress (σ_h) component cannot be less than 0.6 σ_V. Most sedimentary sequences that include shale occur in extensional basins where the maximum horizontal stress (σ_H) is the intermediate stress component (i.e. $\sigma_V > \sigma_H > \sigma_h$). Therefore the three principal stress components are likely to be defined as 23 < σ_V > 115 MPa; 13.8 < σ_h > 115 MPa; 13.8 < σ_H > 115 MPa.

Predicting pore pressure range with depth is more complex. Generally, a hydrostatic pore pressure (u) can be defined by the weight of a water column equal to depth, giving a pore pressure gradient of 10 MPa/km. Therefore pore pressure is likely to range between 10 and 50 MPa in European shale gas operations. However in basins that are bound by low permeability barriers, such as shale cap rock or faults with high clay content, deformation can result in a raised pore pressure, referred to as overpressure. Overpressure can also be observed in shale gas units, Charpentier & Cook (2011) report that it is a desirable attribute in shale gas reservoirs.

The introduction of pore-fluid under pressure has a profound effect on the physical properties of porous solids (Hubbert & Rubey, 1961; Terzaghi, 1943). In a saturated porous system, the fluid supports some proportion of the applied load, creating fluid-pressure (u), which acts in the opposite direction to load lowering overall stress exerted through mineral grains. The addition of u lowers available stress by an amount that is proportional to the pore pressure. The law of effective stress thus dictates that strength is determined not by confining pressure alone, but by the difference between confining and pore-pressures. In simple drained tests, u remains constant and the observed effective stress is similar to the applied load. Conversely, if the pore-fluid system is closed, u rises in proportion to the applied load as pore space is reduced, significantly lowering the overall effective stress. Thus, the mechanical response of rocks to applied load is significantly affected by the ability of fluids to drain. Many rocks have been shown to follow the law of effective stress, including shale (Handin *et al.*, 1963; Kwon *et al.*, 2001). Kwon *et al.* (2001) showed that the effective pressure coefficient χ was equal to 0.99 ± 0.06 for Wilcox shale. This value is indistinguishable from unity and demonstrates that the law of effective stress is obeyed in this particular shale formation. The poroelastic effect (after Biot, 1941) is added to the law of effective stress to account for the partial transfer of pore-pressure to the granular framework. Therefore at the target depth range for shale gas the effective stress is likely to range between 3.8 and 65 MPa, assuming no overpressure.

2.3 Direction of drilling

Hydraulic fracturing requires the drilling of a borehole to the target depth. Advances in drilling techniques have meant that it is now possible to drill both vertically and horizontally (created by deviating a vertical well until horizontal). The advantage to horizontal drilling is that there is a larger surface area in contact with the target formation, meaning there is the potential for a greater reservoir drained volume achieved and increased flow of hydrocarbons into the well. Hydraulic fractures tend to propagate perpendicularly to the direction of least principal stress, following the direction of maximum principal stress (API, 2009). As a result, horizontal wells are drilled in the direction of the minimum principal stress. Experience in the Marcellus Shale in Pennsylvania shows that horizontal wells may extend up to 3,000[2] metres laterally from the well pad (Arthur *et al.*, 2008). Therefore the total length of the well could be in the region of depth + 3,000 m, therefore up to 6,000 metres in length.

2.4 Stages of shale gas extraction

Shale gas extraction consists of three stages (Mair *et al.*, 2012):

- **Exploration.** A small number of vertical wells (perhaps only two or three) are drilled and fractured to determine if shale gas is present and can be extracted. This exploration stage may include an appraisal phase where more wells (perhaps 10 to 15) are drilled and hydraulically fractured to characterize the shale; examine how fractures will tend to propagate; and establish if the shale could produce gas at commercially viable rates. Further wells may be drilled (perhaps reaching a total of 30) to ascertain the long-term economic viability of the shale.

- **Production.** The production stage involves the commercial production of shale gas. Shales with commercial reserves of gas will typically have a gross thickness greater than 50 metres thick and will persist laterally over hundreds of square kilometres. In North America, shales often have shallow dips in relatively structurally simple basins when compared to many in Europe. Vertical drilling would tend to pass straight through them and access only a small volume of the shale. Horizontal wells are likely to be drilled and fractured. The drill bit can be deviated to run horizontally or at any angle in order to maintain the wellbore within the target horizon.

- **Abandonment.** Like any other well, a shale gas well is abandoned once it reaches the end of its producing life when extraction is no longer economic. Sections of the well are milled out and filled with cement to prevent gas flowing into water-bearing zones or up to the surface. A cap is welded into place at the surface and then buried.

2.5 Description of the hydraulic fracturing process

There are several stages to the drilling process as outlined below.

Initially a drill string is used to drill a shallow borehole through the surface layers and casing is inserted into the borehole and cemented in place. This stops the inflow of groundwater and also prevents the borehole from collapsing. The well is then drilled to a greater depth below the base of the local groundwater and further casing is cemented into place. In some cases at this stage a ‘cement bond’ geophysical log may be run to inspect the integrity of the casing and cement. After this the well will be drilled to its target depth and the entire well will be cased and cemented. In some cases the very end

[2] King (2012) report typical horizontal lengths ranging from 2,000 ft to 6,000 ft (600 – 1830 m), with extremes of 12,000 ft or more (3,660 m).

of the well may be left uncased[3], this is called an 'open hole' and can be done to minimise formation damage when the hydraulic fracturing process begins. As stated above, exploration wells will tend to be drilled vertically, whereas production wells are most likely to be deviated to horizontal. Once drilling is complete, the drill string is extracted.

Geophysical logs may be run before or after the final casing is inserted. Wireline logs are very useful for gaining data of target areas which will be the most suitable for the hydraulic fracturing process. There are many techniques which can be employed downhole, such as gamma ray logs, ultrasonic logs, temperature and density logs. Often a combination of these techniques will be used to gain as much information about the formations as possible. These techniques can output properties such as porosity, lithology, acoustic impedance (used to understand the structure of the formation) and permeability. Once this data has been interpreted and the areas identified which the reservoir engineers believe will be the most productive then the hydraulic fracturing process may begin; this is used to increase the local permeability around the well to enhance hydrocarbon flow back to the surface.

Once the well has been drilled, lined, and geophysically logged, the shale formation can be stimulated. The process of hydraulic fracturing is complex and can be split into several key stages, although it must be noted that these stages may be different at each specific site. The process described here is that of multi-stage fracturing; large horizontal wells are split into isolated segments to fracture separately.

(1) **Perforation:** The cementation and lining of the well means that the inside of the well is isolated from the host geology; this is highly desirable above the shale play where potable water aquifers may be present. This stage of the hydraulic fracturing process allows connection of the well to the shale play at the desired depth. Shaped charges (explosives) are pushed down the cased well to the desired well depth. Detonation of these charges perforates the well at given orientations and also results in finger-like fractures or weak points forming in the shale surrounding the well that can be up to 1" (2.5 cm) in diameter and extend 24" (60 cm) into the formation. Pre-perforated liners have been used in some cases; however in-place perforation provides more accuracy for creating perforations at the desired location.

(2) **Isolation:** Initially, perforation occurs at the section furthest away from the well head. This section is then isolated from the rest of the well using a packer.

(3) **Stimulation:** High pressure fluid is then injected into the packered off section of the well. This high pressure fluid has the purpose of increasing the pore pressure in the local area of the perforated borehole, which eventually overcomes the

[3] This is a US practice; regulations within individual EU member states may not allow open hole completion.

tensional strength of the formation, resulting in a network of fractures forming. Fracturing fluid normally consists of water with a range of additives to facilitate the fracturing process (see Section 2.6). A proppant is forced into the fractures by the pressured water and holds the fractures open once the water pressure is released. Sand proppants are often used with this stage repeated several times using different size mesh of sand particles to prop open fractures of different sizes; synthetic polymer beads, or ceramic proppants may also be used. Stimulation may occur over the time-scale of tens of minutes to a few hours, depending on the designed fracture size and volume of the proppant to be placed.

(4) **Flushing:** Further injection takes place to flush out excess proppant and any other objects which may obstruct flow.

(5) **Multi-stage perforation:** The packer is then deflated and pulled further back towards the well head to begin the perforation and injection stage again.

(6) **Flow back:** Once all the packered sections of the well have been stimulated the packers are removed and the fracturing fluid is allowed to flow back towards the surface, leaving the proppants behind to keep the hydraulic fractures open. Gas will now be free to flow back towards the surface.

In recent years effort has been made to increase fracture populations through various advanced hydraulic fracturing techniques. These include the Zipper and Texas Two-Step methods. In the Zipper technique two horizontal wells are stimulated simulateously to maximize stress perturbations near the tips of each fracture (Rafiee *et al.*, 2012). This technique has been adapted into the Modified Zipper technique where fractures are initiated in a staggered pattern, creating a more complex fracture pattern (Rafiee *et al.*, 2012). In the Texas Two-Step method (Soliman *et al.*, 2010) repeat stimulation is performed in an alternate sequence. In conventional stimulation, as described above, the well can be considered as stimulations sites numbered 1 to 10. Conventionally stimulation occurs in order of 1, 2, 3, etc. With Texas Two-Step the stimulation sequence is 1, 3, 2, 4, 6, 5, etc. Any change in fracturing sequence alters the stress in the area between fractures and activates stress-relieved fractures, which can create a complex network of fractures connected to the main hydraulic fractures (Rafiee *et al.*, 2012). This method has been shown to create a more complex fracture network (Roussel & Sharma, 2011)

The complete fracturing process may be repeated when the flow of hydrocarbons begins to decrease, necessitating the well to be re-stimulated. Re-fracturing is typically carried out when the production rates have declined beyond the expected reservoir depletion rate (ICF, 2009). In examples from the Barnett shale, wells were re-stimulated when production declined by between 50 – 85 % of the original production rate (ICF, 2009). However, experience in the states has shown that re-stimulation is likely to be infrequent; either once every 5 – 10 years, if at all (NYSED, 2011). Economics will drive the decision on re-stimulation.

The process of hydraulic fracturing will be tailored for each different geological formation. The properties of the formation and the *in situ* pressure conditions will govern much of the process, such as the fluid injection pressure and the number of stages needed. Shale formations can be heterogeneous and anisotropic so the physical properties of the shale will need to be defined accurately in order for the hydraulic fracturing process to be appropriately managed and as cost effective as possible.

2.6 Fracturing fluids

Fracturing fluid normally consists of water with a range of additives to facilitate the fracturing process and increase fluid flow in the borehole and formation. In some shale gas plays in the US such as those with water-sensitive components (for example, swelling clay) and under-saturated reservoirs, gelled fracturing techniques are used (US EPA, 2010b).

Within the injection fluid is often several chemicals in low concentrations; these are often not disclosed in the U.S. however in certain European states, they must be disclosed to authorities. These chemicals are often a mix of dilute acid, a friction reducer, biocides and an oxygen scavenger aimed to modify fluid mechanics to increase performance of the fracturing fluid or for purposes such as the prevention of corrosion to the well pipes and retardation of bacterial growth. The NYSDEC (2011) state that fracture fluids typically consist of about 98 per cent water and proppant (usually sand, but other granular materials can be used) and 2 per cent additives; this figure is the largest estimate of additive proportion; in the UK about 0.2 % additive has been used (see below). Table 1 summaries the types of chemicals that may be used within the fracturing fluid.

Water used during stimulation often derives from surface or groundwater sources, supplemented by recycled water from previous hydraulic fracturing cycles. Significant quantities of water may be used, depending on well characteristics. Vertical shale gas wells typically use approximately 2,000 m^3 of water; horizontal wells require approximately the same amount of water per stage of stimulation (US DOE, 2009). In the European context, Cuadrilla Resources Limited estimate usage of 12,000 m^3 per horizontal well in the UK (ECCC, 2011), in the Netherlands at Boxtel it has been stated 1,000 m^3/h per 1 – 2 hour stage was used, resulting in 9,000 – 29,000 m^3 of water used (Broderick *et al.*, 2011). For the hydraulic fracturing carried out by Halliburton at the Lubocino-1 well in Poland, 1,600 m^3 of fluid was used.

Cuadrilla in the UK have stated that < 0.05 % of the fracturing fluid is made up of chemical additives (Stamford & Azapagic, 2014), meaning that 6 m^3 of chemicals are used per well based on an estimate of 12,000 m^3 of fracture fluid used. Cuardrilla disclosed the chemical additives used as: 1). Polyacrylamide friction reducers (0.075) suspended in a hydrocarbon carrier; 2). hydrochloric acid (0.125%); and 3). biocide (0.005%), used when the water provided from the local supplier used in the hydraulic fracturing needs to be further purified (DECC, 2014).

Additive type	Description of purpose	Examples of chemicals
Proppant	'Props' open fractures and allows gas / fluids to flow more freely to the well bore.	Sand (sintered bauxite; zirconium oxide; ceramic beads)
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection and provides accessible path to formation.	Hydrochloric acid (3–28%) Muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / biocide / antibacterial agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria, which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde 2,2-Dibromo-3-nitrilopropionamide
Buffer / pH adjusting agent	Adjusts and controls the pH of the fluid in order to maximise the effectiveness of other additives such as crosslinkers.	Sodium or potassium carbonate Acetic acid
Clay stabiliser/ control / KCl	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g. tetramethyl ammonium chloride) Potassium chloride (KCl)
Corrosion inhibitor (including oxygen scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol Ammonium bisulfate for oxygen scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide Borate salts
Friction reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimising friction.	Sodium acrylate–acrylamide copolymer Polyacrylamide (PAM) Petroleum distillates
Gelling agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum Petroleum distillates
Iron control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Scale inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate), which could plug off the formation.	Ammonium chloride Ethylene glycol
Solvent	Additive that is soluble in oil, water and acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol Isopropanol Ethoxylated alcohol

Table 1 – Fracture fluid additives (From NYSDEC, 2011; Broomfield & Donovan, 2012).

For conventional hydraulic fracturing, the fracture pressure gradient is typically 9 – 27 kPa/m. For instance, for a typical 2,400 metre conventional well, this would correspond to approximately 50 MPa and pressures would generally be below 65 MPa.

It should be noted that assuming a 5 inch diameter well with a 6 km length, the volume of the well alone is approximately 75 cubic metres (or approximately 50 cubic metres for a 4 inch diameter well).

2.7 Knowledge gaps and recommendations

This chapter has described the hydraulic fracturing process. It is recommended that all work within the M4ShaleGas project should make reference to the processes employed during hydraulic fracturing. All modelling and laboratory experiments should be conducted in a manner that is representative of the process employed in the field by the shale gas industry.

3 SHALE VARIABILITY

In this chapter we discuss the variability that is inherent in shale formations. Shale is a fine-grained sedimentary rock that constitutes approximately half the geological column (Spears, 1980) and is the most abundant geological rock type present in sedimentary basins worldwide (Meissner, 1986). Few geological rock types encompass such variability and as a result shale successions will have considerable differences in sedimentology, organic content, gas content, and strength properties within individual facies. Thus, shale has been used as a group name for all fine-grained sediments (Spears, 1980). The Dictionary of Geological Terms published by the American Geological Institute (Bates & Jackson, 1984) defines shale as:

> *"A fine-grained detrital sedimentary rock, formed by the compaction of clay, silt, or mud. It has a finely laminated structure, which gives it a fissility along which the rock splits readily, especially on weathered surfaces. Shale is well indurated, but not as hard as argillite or slate. It may be red, brown, black, or gray."*

Even this simplistic definition hints at considerable variation based on visual appearance. In this chapter we will highlight that this variation occurs not only over the geographical extent of a basin and between basins, but also on small distances within the geological succession.

It is outside of the scope of this report to review all of the European potential shale gas basins and to compare these with North American equivalents. Instead, we highlight the variability seen within two boreholes and two field outcrops from the United Kingdom, highlighting variability that will be significant for hydraulic fracturing.

3.1 Carsington Dam Reconstruction C4 borehole, UK

The Carsington Dam Reconstruction C4 borehole, in Derbyshire (UK), was studied extensively by Könitzer (Könitzer, 2014; Könitzer *et al.*, 2014) and is part of on-going research at the British Geological Survey. This shallow borehole (55.25 m deep) was drilled as part of engineering works at Carsington Dam. The borehole intersects lithofacies of organic-rich lower Namurian (Serpukhovian) mudstones from the Widmerpool Gulf, one of several confined early Carboniferous basins in the Pennine Province of the UK. A cored section of 40 metres of Arnsbergian sediments was studied in detail.

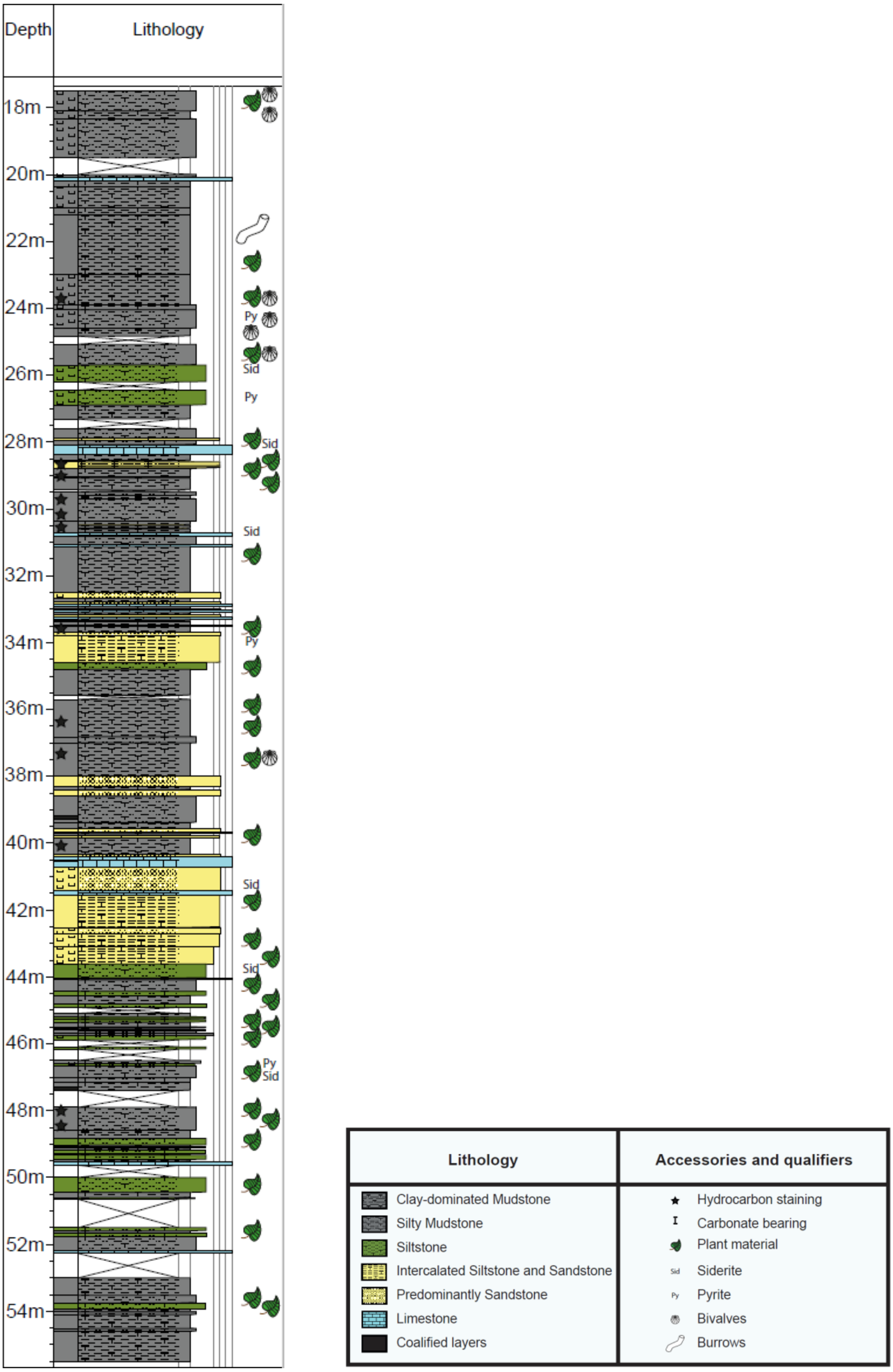


Figure 1 – Sedimentary log of the Carsington Dam Reconstruction C4 borehole, Derbyshire (UK).

Figure 1 shows the sedimentary log of the Carsington Dam Reconstruction C4 borehole. There is considerable variation in lithology over small vertical distances. In a broad sense, the borehole has clay-dominated mudstone, silty mudstone, siltstone, intercalated siltstone & sandstone, sandstone, limestone and coalified layers. Könitzer (Könitzer, 2014; Könitzer *et al.*, 2014) details 7 facies in the sequence; 1) thin-bedded carbonate-bearing clay-rich mudstones; 2) calcareous mudstones; 3) lenticular clay-dominated mudstones; 4) thin-bedded silt-bearing clay-rich mudstones; 5) thick-bedded graded silt-bearing mudstones; 6) sand-bearing silt-rich mudstones; and 7) plant-debris and sand-bearing mudstones. Facies 4 was sub-divided into; a) lenticular thin-bedded silt-bearing mudstones; b) homogeneous thin-bedded silt-bearing mudstones; and c) organic-rich thin-bedded silt-bearing mudstones.

Within the individually identified facies, considerable variation in total organic carbon (TOC) was observed. For facies 1 to 7 the TOC was 2.4 – 6.6, 0.3, 1.9 – 4.5, 0.9 – 4.1, 0.9 – 4.1, 0.4 – 2.8, and 7.1 – 9.7 % respectively. This shows that facies 2 (calcareous mudstone) has a very low TOC, whilst facies 7 (plant-debris and sand-bearing mudstone) has the highest TOC.

The main observation from the Carsington C4 Borehole that is relevant to the current study is the considerable variability seen vertically within a 40 metre sequence of shale. This sequence includes siltstone, mudstone, sandstone, limestone, and coal. The variation is seen on the centimetre and sub-centimetre scale. It should also be noted that Könitzer *et al.* (2014) report considerable variation in lithology thicknesses between the Carsington Dam Reconstruction boreholes C3 and C4, which were separated by less than 50 metres. This shows that not only does shale vary vertically with depth, but does so laterally.

An important consideration is that seismic resolution is often estimated to be 10 – 20 m in ideal conditions. Therefore in twice seismic resolution (i.e. 40m), 7 clear facies and multiple layers of geological variation can occur.

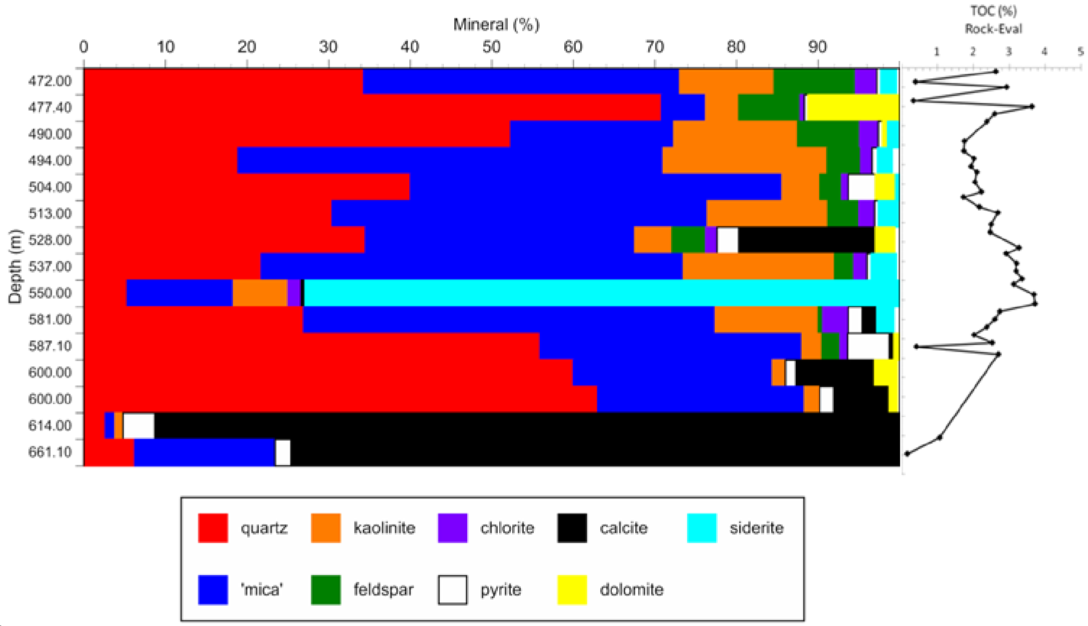
3.2 Roosecote-1 Borehole, UK

The Roosecote-1 Borehole has been studied for variations in physical, mineralogical, and chemical properties at the British Geological Survey. The 800.88 metre deep (TD) borehole is located approximately 3 km to the south-east of Barrow-in-Furness, Cumbria (UK). It was drilled in 1970-71 as an Institute of Geological Sciences stratigraphic borehole. The borehole proved the succession from the Quaternary and bottomed in Lower Carboniferous limestones, and importantly is a defined stratotype section for the Bowland Shale Formation (Dean *et al.*, 2011). The borehole was drilled in the Lancaster Fells Basin, a small basin located in the northern part of the main Craven Basin that is defined by the Lake District Block to the north, and the Bowland High (separating it from the Bowland Basin) to the south. The borehole was fully cored through the Bowland Shale succession, although much of the core was disposed of following palyntological analysis, leaving short core samples typically 5-20 cm long spaced at metre intervals throughout.

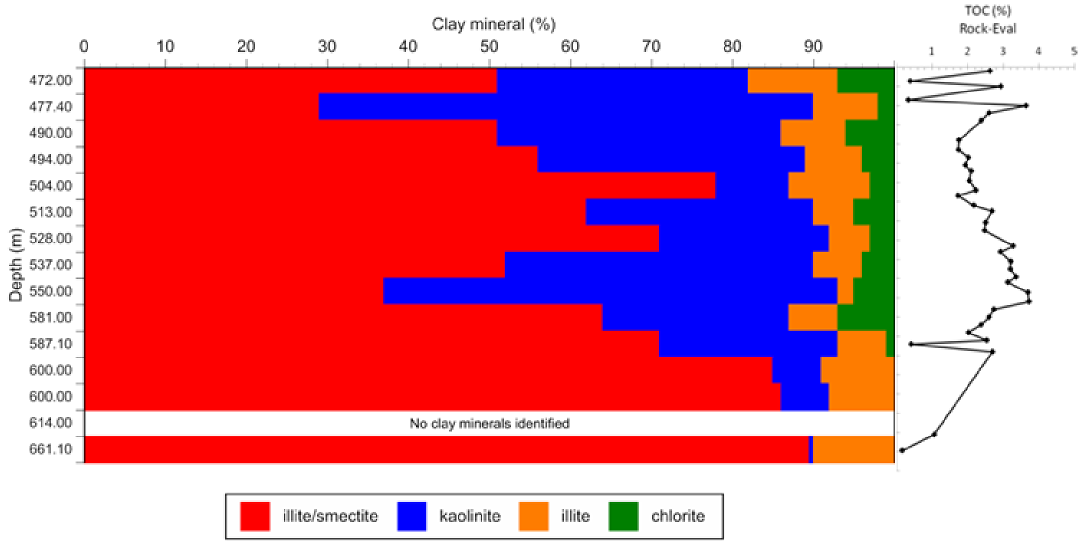
	Description	Thickness (m)	Depth (m)
Namurian	Siltstone to coarsely silty mudstone, dark grey, micaceous, and sandstone pale grey, fine- to medium-grained; interlaminated and interbedded in five major upward fining cycles based at depths of 199.00, 278.68, 326.71, 382.34 and 491.68 metres respectively. Sandstone beds usually predominate in the lower parts of each cycle and often show graded bedding and sharp bases with directional or organic sole structures. A few mudflake conglomerates and chaotically laminated slumped beds are also present. Macrofossils are restricted to rare fish scales and bivalves in the finest lithologies but finely comminuted plant debris is generally abundant. Traces of gaseous oil from 465 m to 487 m	333.55	491.68
	Mudstone, dark grey, silty, with a few siltstone laminae and ferruginous bands	29.80	521.48
	Mudstone, dark grey, slightly calcareous; goniatite/bivalve fauna representing the Cravenoceras malhamense Marine Band	7.59	529.07
	Mudstone, dark grey, silty, with ferruginous bands	23.93	553.00
	Mudstone, dark grey, silty, slightly calcareous; indeterminate marine faunas	2.02	555.02
	Mudstone, dark grey, Silty with fish debris	28.98	584.00
	Mudstone, dark grey, slightly calcareous; marine fauna representing the Eumorphoceras pseudobilingue Marine Band	3.66	578.66
	Mudstone, dark grey, sporadically calcareous, poorly fossiliferous	14.84	608.30
	Mudstone, dark grey, calcareous; goniatite/bivalve fauna representing the Cravenoceras leion Marine Band	5.80	608.30
Visean	Mudstone, dark grey, very silty, micaceous	5.01	613.31
	Limestone, dark grey, very finely granular, bituminous, interbedded with dark grey mudstone; dispersed fine crinoidal debris; 2 mm green mudstone band at 615.59, apparently eroded limestone bedding surface at 616.20; 17 cm bed of conglomeratic mudstone at base	6.38	619.69
	Limestone, coarsely granular, pyritic matrix	0.37	620.06
	Limestone, dark grey, well bedded, finely granular, with dark grey or black mudstone partings every 10-50 cm; bands and nodules of black chert common; thin bands of greey pyritous mudstone at 692.30, 695.24, 704.05 and 704.91 m respectively; very poorly fossililferous except for a 2.27 m bioclastic sequence at 682.94 m with a few indeterminate brachiopod shells and Zaphrentoid corals of probable P_2 age	97.94	718.00

Table 2 – Sedimentary log of the Roosecote-1 borehole, Cumbria (UK).

The preliminary sedimentary log (Table 2) produced at the time of drilling describes the detail for the Carboniferous (Namurian and upper part of Visean) part of the succession. The sedimentary log shows that a range of geological lithologies were observed within the shale formation; including siltstone, sandstone, mudstone, limestone, and nodules of chert.



a).



b).

Figure 2 – Results of XRD and TOC (Rock-Eval) analysis on samples taken from Roosecote-1; a) Whole rock analysis; b) < 2 µm fractions.

Figure 2 shows the results of X-ray diffraction (XRD; Cave *et al.*, 2013; Kemp *et al.*, in prep) and total organic carbon (TOC) as determined by Rock-Eval pyrolysis (Hough *et al.*, 2014) from 14 samples taken along the Roosecote-1 borehole. As can be seen, considerable variability in mineralogy is seen for the bulk-rock along the sequence studied from 472 – 661 metres depth. Quartz content, for instance, varies significantly between 2.6 and 70.8 %, while siderite is very low or below detection limits in all but one sample where it accounted for 72.9 %. Considerable variation is also observed in the clay content, with illite/smectite ranging from 29 – 86 %. Variability is observed in

TOC in the organic rich shale units, which ranged between 1.76 and 3.72 %, with a mean of 2.6 %. Certain intervals had very low TOC readings.

The Roosecote-1 borehole shows that within a 190 metre sequence of shale a range of lithologies are observed including siltstone, sandstone, mudstone, limestone, and nodules of chert. This is reflected in the mineralogy measured using XRD on the bulk rock, and also on the clay content obserevd on fractions of less than two microns. Variation is also seen in the TOC, showing that certain facies will not be propspective.

3.3 Mam Tor and Edale outcrops, UK

In this section we describe variations seen in shale at outcrops in the UK. Figure 3 shows an exposure that clearly shows variation in lithology in the dipping shale sequence at Mam Tor, Derbyshire (UK). The dark-grey shales include harder beds, these are turbidite sandstones and include some ironstones. This photo clearly shows variation over a sequence of about 4 metres. Note also that a close-spaced joint development is present within the harder lithologies.

A finer-scale variation in shale is shown in Figure 4 and Table 3. This example was observed at Edale in Derbyshire (UK) and represents 8.4 metres of the shale succession from the Bowland Shale Formation. The pale layers seen in Figure 4 are much harder ironstone bands and lenses. The sedimentary log (Table 3) shows a range of lithologies, including mudstone, ironstone, and claystone. Some of these facies were as thin as 5 cm, with the thickest being less than 2 metres. It should also be noted that Figure 4 shows a fault running through the sequence with clear offset of beds.

Figure 3 – Photo of the shale formation at Mam Tor, Derbyshire (UK).

Figure 4 – Photo of the shale formation at Edale, Derbyshire (UK).

Facies	Thickness (m)
Mudstone, dark grey, very thinly bedded, fissile, harder bands are non-calcareous, sharp base	1.8
Ironstone	0.06
Ironstone, thin and interbedded **mudstone**, dark grey, fissile	0.95
Ironstone	0.05
Mudstone, lighter grey in weathered section, thin bedded, nodular, non-calcareous with very thin ironstones	0.8
Mudstone, dark grey, very thinly bedded, fissile	0.7
Ironstone band	0.08
Mudstone, dark grey, fissile, becoming less calcareous upwards, thin interbedded ironstone bands in upper part	0.5
Gap, vegetated but probably the same unit as below	0.5
Claystone, dark grey, fissile, very thinly bedded with very thin lenticles of wispy paler calcareous mudstone	0.9
Mudstone, dark grey, very thin bedded, lenticular calcareous zones, small goniatite seen; with fairly sharp base	0.35
Claystone, dark grey, fissile, no mica, very homogeneous, gradational base	1.1
Mudstone, dark grey, fissile with large calcareous bullions	0.6
TOTAL	8.39

Table 3 – Thickness of beds observed at Edale, Derbyshire (UK).

These field exposures clearly show variations in physical properties over short distances in shale sequences; differences can clearly be seen in weathering rates. Individual beds have been observed to have as little as 5 cm thickness, with the thickest beds of the order of 2 metres thick.

3.4 Variations in physical properties

The examples listed above show that "shale" formations can include mudstone, claystone, ironstone, sandstone, limestone, coal measures and chert nodules. This variability is likely to be evident in differences in physical properties.

Rock type	Dry density (g/cc)	Porosity (%)	Dry UCS range (MPa)	Dry UCS mean (MPa)	Young's modulus (GPa)	Tensile strength (MPa)	Shear strength (MPa)
Greywacke	2.6	3	100-200	180	60	15	30
Sandstone (Carboniferous)	2.2	12	40-100	70	30	5	15
Limestone (Carboniferous)	2.6	3	50-150	100	60	10	30
Mudstone (Carboniferous)	2.3	10	10-50	40	10	1	
Shale (Carboniferous)	2.3	15	5-30	20	2	0.5	
Clay (Cretaceous)	1.8	30	1-4	2	0.2	2	0.7
Coal	1.4	10	2-100	30	10	2	
Ironstone#				190		44	
TOTAL RANGE	1.4-2.6	3-30	1-200	2-190	0.2-60	0.5-44	0.7-30
MEAN	2.2	12		79	25	10	19

Table 4 – Typical physical properties of lithologies seen within shale formations. From Waltham (1994) and Hobbs (1964).

Table 4 shows typical physical properties for the lithologies listed above. The uniaxial compressive strength (UCS) is often used as a comparative measure of strength. A UCS range of 2 to 190 MPa represents a rock classification from weak to strong rock (Waltham, 1994). A weak rock can be viewed as one that crumbles under a pick blow, whilst a strong rock can be broken by a hammer in the hand. The average UCS of 79 MPa represents a moderately strong rock; one which can be dented with a hammer pick. The tensile strength is of direct relevance to hydraulic fracturing. The range of lithologies have tensile strengths of between 0.5 and 44 MPa, with an average of 10 MPa. This clearly shows that certain beds will be much easier to hydraulic fracture than others. It should, however, be noted that the simplistic data represented in Table 4 does not capture the full range in physical properties seen within highly variable shale sequences.

3.5 Knowledge gaps and recommendations

This chapter has introduced the variability seen within shale sequences. The following statements on our current knowledge, knowledge gaps and recommendations can be made:

- The term “shale” includes complex sequences of geological beds that include siltstone, mudstone, sandstone, limestone, ironstone, coal, and chert. These vary over the centimetre scale vertically and vary in thickness and extent laterally. This variation may occur over the 10’s centimetre to 100 meter scale. Making accurate predictions of the full sedimentary sequence is thus very difficult. A better understanding of geological sequence stratigraphy is needed in order to understand the control this variability has on hydraulic fracturing.
- The mineralogy seen within geological sequences varies considerably and this is also evident in total organic carbon (TOC). Hydraulic stimulation may be more successful in certain beds and these might not necessarily be high in TOC. Therefore recoverability will be dependent on both TOC and ease of hydraulic fracturing. A better understanding is needed of both of these properties so that hydraulic fracturing does not just occur where high TOC occurs.
- Bedding thickness is variable, ranging upwards from thinly laminated (less than 6 mm) but typically less than very thickly bedded (2m). This range in bed thickness is much less than the seismic resolution of 20 metres and therefore the full variability of shale sequences cannot be achieved by seismic techniques alone. The significance of such small beds needs to be understood and the risk of failing to determine the full geological sequence from geophysical methods needs to be assessed.
- The strength properties of litholigies found within shale formations has a considerable range. A better understanding of the variability in physical properties relevant to hydraulic fracturing is required. The interplay between mineralogy and strength also requires more research.
- This chapter has given examples from the United Kingdom. A better understanding of the variability of shale within Europe is required. Similarities are likely, as are differences that are specific to individual basins or geological domains.

4 FRACTURE INITIATION

This chapter introduces the mechanisms responsible for the formation and initiation of hydraulic fractures following perforation of the well casing. Chapter 5 then concentrates on the propagation of these fractures.

4.1 Basic concepts

In this section we introduce the basic concepts of rock mechanics relevant to the stress state that shale at depth will be subjected.

As introduced in Chapter 2, rocks at depth are subject to a complicated, heterogeneous, stress field. The vertical component of stress is related to the weight of overlying rock, which is partially transmitted into the horizontal sense (the Poisson effect). Additional horizontal stresses are created by erosion (Goodman, 1989), tectonic activity arising from lithospheric resistance to plate motion, rock anisotropy, and geological discontinuities. The result is a complex stress-field, which is described locally by an orthogonal set of normal (σ) and shear (τ) stresses (Figure 5a). It should be noted that the principal stress components corresponding to maximum (σ_1), intermediate (σ_2), and minimum (σ_3) stress do not necessarily correspond with vertical (z) and horizontal (x, y) directions, as exaggerated in (Figure 5b). It is often simplified that the maximum stress component (σ_1) corresponds with the vertical direction.

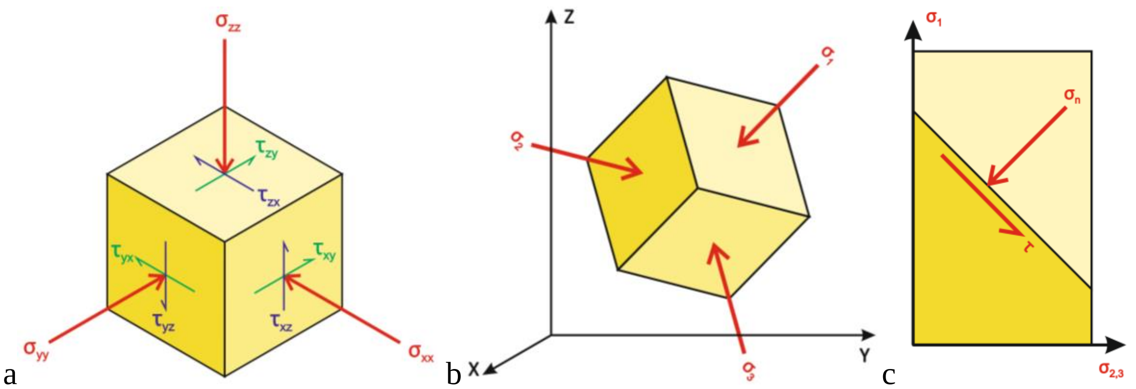


Figure 5 – Three-dimensional coordinate system of a) General stress components, b) Principal stress components, c) Stresses acting on a discontinuity.

Another aspect to consider when discussing the stresses acting on a rock is the pressure from the fluid held within the pore space. This acts in the opposite direction to the normal stress, the result is an effective pressure which can be expressed as:

$$\sigma' = \sigma_n - u$$

where σ' is the effective stress, σ_n is the normal stress and u is the pore pressure acting on the rock.

When acting on a plane, stress can be split into a normal and shear component (Figure 5c). Normal stress (σ_n) acts perpendicular to a plane whereas the shear stress (τ) acts parallel to this plane. Normal compressive stress tends to inhibit sliding along a plane; shear stress tends to promote sliding. Normal stresses are considered to be positive if they are compressive and negative if they are tensile. Shear stresses are labelled according to their sense of shear.

The stresses that a rock is subjected can result in deformation; which may be recoverable (elastic) or permanent (plastic or inelastic) when stress is relieved. In many regions, the upper crust is subject to shear stresses approaching the frictional strength of favourably orientated faults (Engelder, 1992). This results in a state of limiting equilibrium within the crust with rocks at depth close to the point of failure according to the frictional characteristics of the rock. Deformation can present itself in rocks in many forms; for instance faults, fractures, joints, compaction bands, mineral alteration, cementation, grain crushing or porosity reduction.

4.1.1 Elastic behaviour

Elastic deformation is often the initial response of geological materials to an applied stress and strain. This deformation is fully recoverable and non-permanent once the load is removed (Figure 6). The elastic moduli of Young's Modulus (E), Poisson's ratio (v), Bulk Modulus of Compressibility (K) and the Shear Modulus (G) describe a rock's stiffness, translation of strain in one principal direction into the other principal directions, resistance to volume change, and resistance to shear deformation respectively. The elastic moduli allow predictions of deformation state for a given stress condition. Wholly elastic responses are rare in geological materials and may only occur at very low strain rates. This is mainly due to the natural heterogeneity of rocks and the stress field. However, knowledge of the elastic properties allows the initiation of fractures to be predicted.

4.1.2 Inelastic behaviour

All materials have a limit at which permanent (inelastic or plastic) deformation occurs (Figure 6a); often referred to as yield. Rock deformation can either be plastic, ductile or brittle. The mode of deformation which may occur is governed by the stress state, material properties, temperature and hydraulic conditions.

Brittle behaviour represents a near-instantaneous stress reduction (Figure 6b) involving some combination of fracture and frictional sliding, and is common in rocks at low pressures and temperature. Usually less than 1% elastic strain occurs before failure and results in fault or fracture formation. Stable frictional sliding along fractures requires less energy than fracture initiation ($\mu_{dynamic} < \mu_{static}$), resulting in a stress-drop. Failure is observable on a wide range of scales, from microscopic to regional scale, as observed in the upper crust from microcracks to continent scale strike slip zones. Low porosity, well indurated argillaceous rocks, such as shale, behave in this manner depending on the rate of strain.

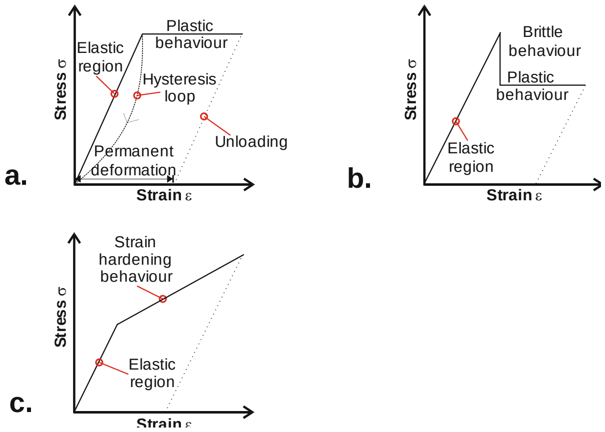


Figure 6 – Basic models of rock deformation: a) elastic-plastic behaviour, b) elastic-brittle-plastic behaviour, c) elastic-strain hardening behaviour.

Certain rock types display a stress-strain relationship where yield-stress is achieved, but a peak-stress is never attained due to continual work-hardening (Figure 6c). This is what occurs when deformation becomes increasingly difficult as the strain increases. These conditions are said to be fully mechanically ductile (Jaeger & Cook, 1979). Ductility can be viewed as rock 'flow', with rupture occurring, if at all, after at least 10% shortening. Poorly indurated argillaceous rocks may behave in this manner. The transition from brittle to ductile behaviour occurs as confining pressure increases and therefore mode of deformation is dependent on depth and the physical properties of the rock.

4.1.2.1 *Pore pressure effects*

As described in Chapter 2.2 the fluid within pores exerts a pore fluid pressure (u), which acts in the opposite direction to the confining pressure (σ), forming an effective pressure (σ'):

$$\boldsymbol{\sigma}' = \boldsymbol{\sigma} - u$$

Stresses within shale are therefore described in terms of the effective stress as it dictates deformation. The effect of pore pressure is best shown by Figure 7. The principal stresses are plotted as a circle in Mohr's space, along with the Coulomb failure criterion in the compressional deformation field and a tensile failure criterion in the tensile stress field. The failure criteria are used to predict the stress conditions when permanent deformation will occur. The addition of pore fluid pressure can be seen to move the Mohr circle to the left. Therefore, under a static boundary condition (i.e. no change in rock stress), the addition of pore pressure can change the likelihood of deformation. Figure 7a represents the case of fracture reactivation. A pre-existing plane of weakness, oriented at θ to the stress field, is shown on the Mohr diagram. The addition of pore fluid pressure moves the Mohr circle to the left until this plane of weakness intercepts the Coulomb failure criterion, resulting in shear deformation in the compressional deformation field. Figure 7b shows the example of hydrofracture. The addition of pore fluid pressure has resulted in the Mohr circle intercepting the tensile fracture criterion at a stress of T_0. This results in the formation of tensile hydrofractures.

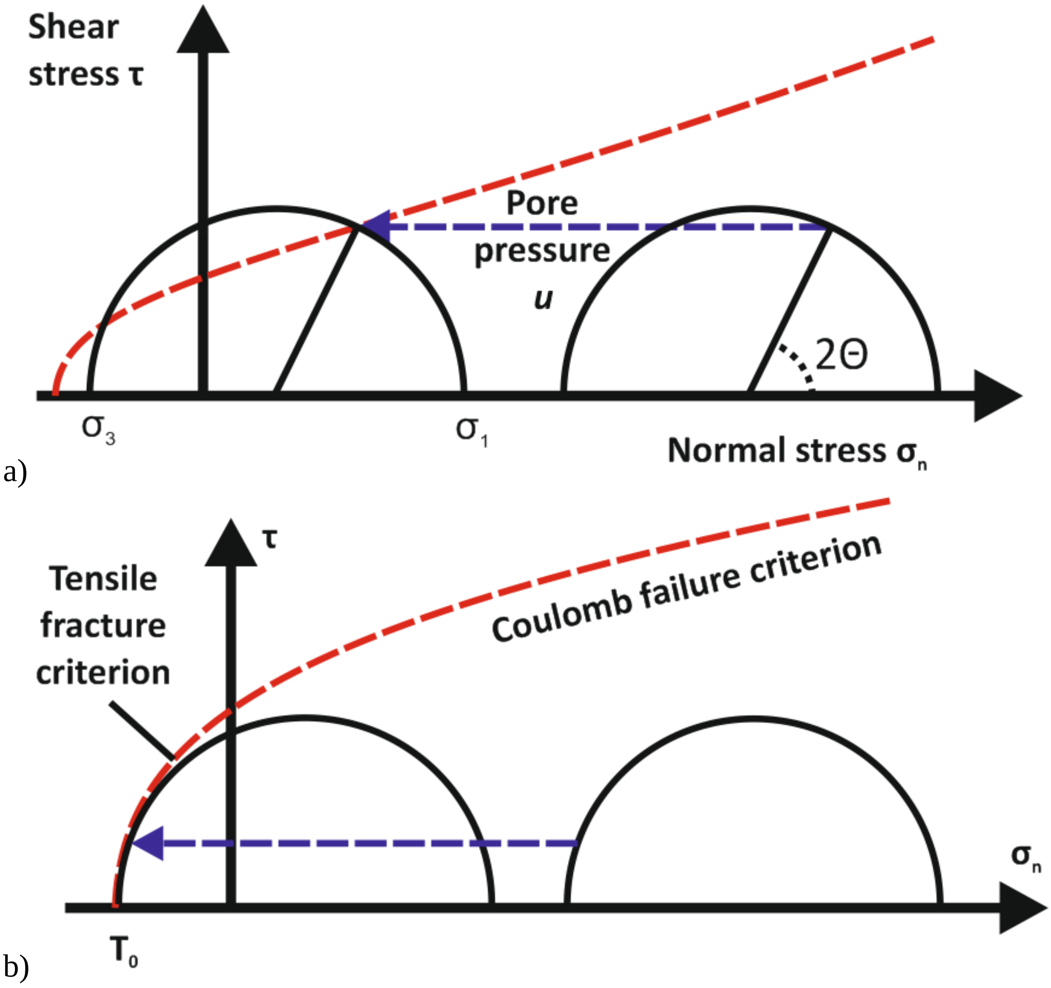


Figure 7 – Prediction of failure using the Mohr diagram approach: a). the case of fracture reactivation; b) the case of tensile hydraulic fracture formation.

The injection of fluid at a high pressure acts to move the effective stress of the rock to beyond the failure envelope; therefore failure occurs and fractures form. Gas is then free to flow out of the shale unit and into the well. This report will mainly focus on the mechanical properties of shale rocks; however there is clearly a large interaction between the mechanical properties and hydraulic properties of rocks which must be considered. As shown, pore pressure can either result in the reactivation of pre-existing discontinuities (faults, fractures, joints, etc) or the formation of new hydrofractures. In practice a combination of both is likely to occur, with shear deformation occurring along pre-existing microfractures, the formation of new hydrofractures and the extension of new hydrofractures at the tips of pre-existing fractures.

4.2 Stress concentration around a borehole

It has been stated that shale at prospective depth is under a state of stress dictated by the weight of the overburden and tectonic forces that might also act on the sedimentary basin. If a circular hole is made in a stressed plate, the stress distribution around the hole will be changed (Timoshenko & Goodier, 1970), i.e. as a borehole is drilled, the rock surrounding the hole must carry the force previously carried by the removed rock. This can be described as a conservation of energy. Although mass is removed ($\delta M \neq 0$), energy, and therefore stress, is not, and the condition of Laplace ($\nabla^2 \sigma_x + \sigma_y = 0$) still has to be met. The solution for the stress modification around a circular opening in a uniaxially loaded infinite plate was given by Kirsch in 1898 (Timoshenko & Goodier, 1970). The Kirsch solution is easily modified to consider biaxial loading and the effect of pressure within the hole (Jaeger & Cook, 1979):

$$\sigma_r = \frac{\sigma_H + \sigma_h}{2}\left(1 - \frac{r^2}{R^2}\right) + \frac{ur^2}{R^2} + \frac{\sigma_H - \sigma_h}{2}\left(1 - \frac{4r^2}{R^2} + \frac{3r^4}{R^4}\right)cos2\theta$$

$$\sigma_\theta = \frac{\sigma_H + \sigma_h}{2}\left(1 + \frac{r^2}{R^2}\right) - \frac{ur^2}{R^2} - \frac{\sigma_H - \sigma_h}{2}\left(1 + \frac{3r^4}{R^4}\right)cos2\theta$$

$$\tau_{r\theta} = -\frac{\sigma_H + \sigma_h}{2}\left(1 + \frac{2r^2}{R^2} - \frac{3r^4}{R^4}\right)sin2\theta \qquad \textbf{Eq. 1}$$

where σ_r is radial stress, σ_θ is circumferential or hoop stress, $\tau_{r\theta}$ is shear stress, r is the radius of the bore, u is pore pressure, R is distance from centre of bore to point where stresses are being calculated, θ is the angle made between R and σ_H. This solution results in a stress concentration around the periphery of the bore with regions where stress is increased and regions where it is decreased. It can be shown that tensile stresses form in the direction of the maximum far-field stress direction. Therefore a complex stress is formed around a borehole, which if greater than rock strength, results in compressional or extensional failure in and behind the borehole wall.

The boundary conditions are such that hoop stress (σ_θ) at the bore-surface varies from $3\sigma_h$ - σ_H when $\theta = 0$ to 3 σ_H - σ_h when $\theta = ½\ \pi$. Thus, an area of tensile (negative) stress is created in the maximum far-field stress direction ($\theta = 0$). When u is zero, tensile stresses are absent from all points if $3\sigma_h > \sigma_H$. Tensile stresses are created in the bore-surface if $u > 3\sigma_h - \sigma_H$ with radial tensile failure possible.

The Kirsch solution in a biaxial stress-field (as given in Jaeger & Cook, 1979) is applicable to a borehole aligned with one of the principal stress directions and tends to be considered for a vertical borehole. The stress-field is greatly complicated by deviating the wellbore or by drilling horizontally. Hossain *et al.* (2000) give the solution to the stress-field as:

$$\sigma_x = (\sigma_h cos^2\beta + \sigma_H sin^2\beta)cos^2\psi + \sigma_v sin^2\psi$$

$$\sigma_y = \sigma_h sin^2\beta + \sigma_H cos^2\beta$$

$$\sigma_z = (\sigma_h cos^2\beta + \sigma_H sin^2\beta)sin^2\psi - \sigma_v cos^2\psi$$

$$\tau_{yz} = 0.5(\sigma_H - \sigma_h)sin2\beta sin\psi$$
$$\tau_{zx} = 0.5(\sigma_h cos^2\beta + \sigma_H sin^2\beta - \sigma_v)sin2\psi$$
$$\tau_{xy} = 0.5(\sigma_H - \sigma_h)sin2\beta cos\psi \quad \textbf{Eq. 2}$$

where σ is normal stress, τ is shear stress, β is wellbore deviation, ψ is wellbore inclination, σ_x, σ_y, σ_z are stress in the direction of the borehole with z parallel to the well, and σ_H, σ_h, σ_v are the principal stresses.

As stated in Section 4.1, the far-field stress is usually markedly distinct from homogeneous and shale at depth is subjected to a triaxial stress-field. What the numerical solutions introduced above show is that the stress field around the well is greatly complicated by this far-field stress and the stress concentrations created in the borehole wall. Changes in pore fluid pressures, such as during hydraulic stimulation, are most likely to create tensile fracturing in the direction of the maximum horizontal principal stress.

4.3 Tensile fracturing

Hydraulic fracturing (tensile Mode I fracturing) can occur:

- Naturally, due to the tectonic regime and changes in the effective stress conditions (hydrofractures)
- Artificially, due to drilling activities (drilling-induced tensile fractures)
- Artificially, generated around a tunnel or borehole due to changes in the *in situ* stress conditions.

Hydrofactures may be large features, or a linked, permeable, dilatant fracture network. These changes may be induced by the development of disequilibria pore pressure conditions or by changes in the tectonic load. For example, a reduction in the minimum compressive stress (σ_3), induced by extension during regional uplift, may result in the formation of dilatant shear fractures. Hydrofractures occur under conditions of low differential stress when pore fluid pressure reduces the minimum effective horizontal stress below zero to the tensile strength of the rock.

In extensional basins, where the minimum compressive stress (σ_3) is significantly less than the maximum compressive stress (σ_1), hydrofractures are invariably vertical to semi-vertical in orientation and form perpendicular to σ_3. For hydrofractures to develop in preference to shear fractures, the following conditions must be satisfied:

$$u_f = \sigma_3 + T_0$$
$$\sigma_1 - \sigma_3 < 4T_0 \quad \textbf{Eq. 3}$$

where u_f is pore fluid pressure required to initiate hydrofracture, σ_1 and σ_3 are maximum and minimum horizontal stresses respectively and T_0 is the tensile strength of the cap-rock (Hubbert & Rubey, 1959; Sibson, 1995). These conditions can occur in highly overpressured systems undergoing continual subsidence, or during exhumation when rapid denudation, without re-equilibration of overpressure, results in tensile failure. Brittle shale will increase its permeability by developing dilatant fractures, whereas ductile shale is able to undergo plastic deformation without increasing permeability (it will contain non-dilatant, sealing fractures). The tendency to dilate will be a function of the mechanical properties of the rock, effective pressure and shear zone geometry. At a given effective pressure, a stronger (over-consolidated or cemented) rock is more likely to dilate than a weaker one.

Considerable research has been conducted in connection with the engineering of wells to investigate the generation of artificial hydraulic fractures in order to determine *in situ* stress. The hydrofrac (HF) test measures *in situ* stress down a borehole by increasing the pore fluid pressure in an isolated segment until tensile hydraulic fracturing is initiated, identified by a drop in pore fluid pressure. Breakdown pressure (u_c) is defined as the borehole pressure necessary to initiate hydraulic fracturing. There are two classical HF criteria to establish equations between u_c and *in situ* horizontal principal stresses (Song *et al.*, 2001); one is based upon elastic theory for impermeable rocks (Hubbert and Willis, 1957); the other upon poroelastic theory and considers the poroelastic stress induced by fluid permeation into rocks (Haimson & Fairhurst, 1967). This has been extended to include the characteristics of the bore during pressurisation (Detournay & Cheng, 1992):

Hubbert & Willis (1957): $$u_c - u_0 = T_{hf} - 3\sigma_h + \sigma_H - 2u_0 \qquad \textbf{Eq. 4}$$

Haimson & Fairhurst (1967): $$u_c - u_0 = \frac{T_{hf} + 3\sigma_h - \sigma_H - 2u_0}{2 - 2\eta} \qquad \textbf{Eq. 5}$$

Detournay & Cheng (1992): $$u_c - u_0 = \frac{T_{hf} + 3\sigma_h - \sigma_H - 2u_0}{1 + (1 - 2\eta)h(\gamma)} \qquad \textbf{Eq. 6}$$

where u_0 is initial pore pressure in the rock formation, T_{hf} is the hydraulic fracturing tensile strength, and η and γ are the poroelastic parameter and dimensionless pressurisation rate respectively, given by:

$$\eta = \frac{\alpha(1-2\nu)}{2(1-\nu)} \quad 0 \le \eta \le 0.5 \quad \text{and} \quad \gamma = \frac{A\lambda^2}{4cS} \quad 0 \le \lambda \le \infty \qquad \textbf{Eq. 7}$$

where α is the Biot parameter (Biot & Willis, 1957), ν is the Poisson ratio, A is borehole pressurization rate, λ is the microcrack length scale, c is the diffusivity coefficient, and S is stress.

4.4 Basic Fracture Mechanics

To fully understand the physics behind hydraulic fracture development and propagation in shale rocks we must first understand the basic mechanics which underlies fracturing in geological materials. This first requires the understanding of the modes in which fractures form and then the basic theory which governs the behaviour observed. Discontinuities originate from the build-up and concentration of stress at the tips of natural weaknesses and heterogeneities (USNCRM, 1996). These natural heterogeneities are a result of the mechanical properties of the rock and the rocks response to lithostatic (uplift, erosion and weathering), tectonic and thermal stresses, together with variations in fluid pressures. The mechanics that underpin fracture processes derives from classic work by Griffith (1921) and Irwin (1958).

The Griffith theory is based upon the linear elastic theory, which states that the stress at a tip of a narrow fracture is infinite. As a crack grows this requires two new surfaces to be created which in turn creates what Griffith calls a surface energy, C, expressed as:

$$C = \sqrt{\frac{2E\gamma}{\pi}} \qquad \textbf{Eq. 8}$$

where C is the surface energy, E is the materials Young's Modulus and γ is the surface energy density. Failure occurs when free energy attains a peak value at a critical crack length, beyond which the fracture energy will decrease and the crack length will increase.

Irwin (1958) further developed the Griffith model as the classic model only accounts for pure brittle materials such as glass. In ductile materials a plastic zone develops at the crack top, as load increases the plastic zone increases in size until the crack grows in length. This plastic zone acts to provide a resistance to the crack growth. Irwin split the energy into two parts, the stored elastic strain energy which is released as the crack grows (thermodynamic driving force) and the dissipated energy which includes plastic dissipation and the surface energy, therefore:

$$G = 2\gamma + G_p \qquad \textbf{Eq. 9}$$

where γ is the surface energy, G_p is the plastic dissipation, G is the total surface energy. When applied to Griffith's theory:

$$\boldsymbol{\sigma_f \sqrt{a}} = \sqrt{\frac{\boldsymbol{EG}}{\boldsymbol{\pi}}} \qquad \textbf{Eq. 10}$$

where, a is the microcrack length, E is the materials Young's Modulus and σ_f is the stress at fracture. Irwin further developed this to calculate the magnitude of energy available for fracture by taking into account the asymptotic stress data displacement fields around a crack front:

$$K_I = \lim_{n \to 0} \sqrt{2\pi r}\,\sigma_{yy}(r,0)$$

$$K_{II} = \lim_{n \to 0} \sqrt{2\pi r}\,\sigma_{yx}(r,0)$$

$$K_{III} = \lim\nolimits_{n \to 0} \sqrt{2\pi r}\,\sigma_{yz}(r,0) \qquad \textbf{Eq. 11}$$

where K is the stress intensity factor. The magnitude of this depends on geometry, size, location, and load distribution. The stress intensity factor is directly proportional to the applied load on the material. It is possible to determine the minimum value of K which is required to propagate the crack; this minimum value is referred to as the critical stress intensity factor K_c. Using a combination of Irwin and Griffith fracture mechanics it is possible to determine the shape of the stress field and the magnitude, using the stress intensity factor.

4.4.1 Dependent variables of hydraulic fracturing

The theory introduced above shows that the initiation of fracture formation is dependent on a number of factors. These include: the orientation and size of the borehole; orientation and magnitude of the stress-field; pressure and rate of increase of the hydraulic fracture fluid; pore fluid formation of the shale; elastic properties of the shale, including elasticity, poroelasticity, and tensile strength; and the crack properties, such as stress intensity factor and surface energy. These parameters will dictate where a fracture is initiated and consequently, the direction of fracture propagation.

It should be noted that the theory above is based on a homogeneous elastic medium. Shale is a complex heterogeneous material with strong directional variation in many properties that need to be considered when predicting where fracture initiation will occur. It is also important to consider that the starting shale is not pristine; the action of perforation will create weaknesses within the shale surrounding the well. Perforations need to be directed with respect to the stress-field so that they are in phase with the anticipated fracture direction (Hoassain *et al.*, 2000). Perforations have been shown to reduce longitudinal fracture initiation pressures when preferentially oriented (Hoassain *et al.*, 2000).

4.4.2 Fracture mode

At the tip of a microcrack, the concentration of stress results in the creation of many small microcracks in a non-linear process zone. Microcrack communication lengthens the features, and propagates the process zone into the rock mass in the direction of the maximum compressive stress trajectory. Several processes control or influence discontinuity propagation, including elastic strain accumulation, crystal-plastic processes, diffusion processes, phase transformations and reactions, and fluid processes.

The propagation of fractures is clearly related to the stress state of the rock. The state of stress is often heterogeneous and this therefore has an effect on the mechanics of fracture formation and the type of fracture which may form. At all but the shallowest depths within the Earth, the far-field stress components S_1, S_2 and S_3 are compressive, and in most locations they are of different magnitudes (Gay & Weiss, 1974). Two distinct discontinuity types exist in compression, namely shear and extension (Griggs & Handin, 1960). Three displacement modes act on an ideal, flat, perfectly sharp discontinuity (Figure 8):

- Tensile or opening (mode I)
- In-plane shearing or sliding (mode II)
- Anti-plane shearing or tearing (mode III).

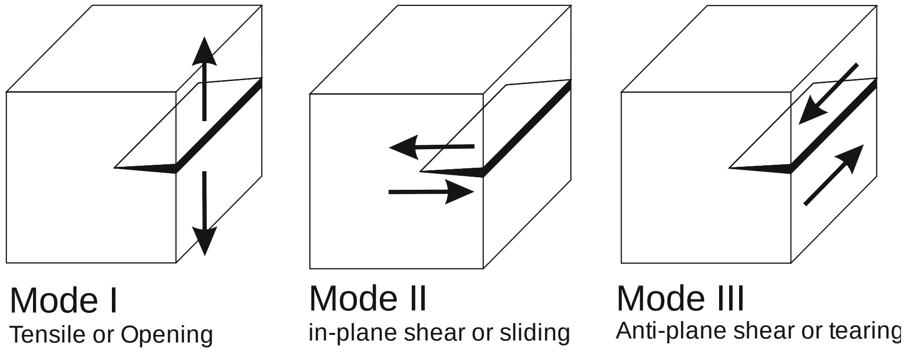


Figure 8 – Schematic representation of the three fundamental modes of discontinuity displacement.

The injection of high pressure fluid along with proppant materials during the hydraulic fracturing process will result in predominantly Mode I open fractures forming; these will form parallel to the maximum principal stress. However, Ferril *et al.* (2012) state that there will also be an element of Mode II fractures forming, as shearing of the rock mass will also take place during fracturing; this may result in a Mode IV fracture type which can be called a hybrid fracture.

It is important to understand the direction and magnitude of these hydraulic fractures in order to be able to predict productivity and the development of the fractured disturbed zone. Hydraulic fractures are predominantly tensile or opening (Mode I) fractures, meaning they will propagate perpendicular to the minimum principal stress (σ_3). Therefore in order to predict the orientation of these fractures it is essential to have a detailed knowledge of the stress field within the target area. The stress state is considered to be a major factor that can influence rock deformation (Warpinski *et al.*, 1982; Busetti *et al.*, 2014; Ferril *et al.*, 2012). Reservoir depth and the tectonic stress regime are considered the major influencing factors, as well as the *in situ* pore pressure.

Shale plays in the United States are situated at a range of depths and stress states, as summarised by Table 5.

Sample Group	Depths (m)	*In situ* Stress (MPa)
Barnett – 1 **Barnett – 2**	2,600	$\sigma_v = 65$ $u = 30$ $\sigma' = 35$
Haynesville – 1 **Haynesville – 2**	3,450	$\sigma_v = 85$ $u = 60\text{-}70$ $\sigma' = 15\text{-}25$
Eagle Ford – 1 **Fort St. John**	3,800	$\sigma_v = 90$ $u = 65$ $\sigma' = 25$ $\sigma_v = 25$ $u = 10\text{-}12$ $\sigma' = 13\text{-}20$

Table 5 – State of stress within shale gas plays of the United States (From Sone & Zoback, 2013).

4.5 Physical properties of shale

Chapter 3 highlighted the variability seen in shale in terms of properties such as mineralogy, kerogen content and tectonic setting. The location and initiation pressure of fractures requires knowledge of these parameters.

4.5.1 Mineralogy

As discussed in Chapter 3 shale mineralogy can vary greatly, but will predominantly contain a significant portion of clay minerals along with a combination of quartz, feldspars and carbonate minerals. The mineralogy of a shale unit is often used to predict the way in which it may deform under a certain stress field. It is generally agreed that a large portion of quartz and carbonate minerals will mean the shale is likely to deform in a brittle manner. Whereas, a larger clay content will more likely result in more plastic deformation. Therefore, hydraulic fracture treatments are more likely to be targeted in areas with higher quartz and carbonate contents as they will be more likely to fracture. This does not mean a shale with a high clay content will not be a productive formation, for example the Barnett Shale has areas with a clay content of up to 39 % (Sone & Zoback 2013), this is also the case for the Haynesville field. This rule can also apply to the quartz content, which is as low as 11% in some parts of the Eagle Ford shale (Sone & Zoback 2013); this is however compensated by a carbonate content of up to 78%. As well as mineralization, the degree of cementation (or induration) can also influence whether brittle or ductile deformation is likely. More indurated shale will behave in a brittle manner. Even plastic clays will hydrofracture if the rate of pressurization is high enough.

4.5.2 Elastic properties

The initiation of hydraulic fractures is dependent on the elastic properties of the shale; these can either be derived from wireline geophysics *in situ* or through laboratory experimentation. The ability to derive elastic properties from non-intrusive wireline logs make deriving understanding on hydraulic fracturing based on elasticity favourable.

4.5.2.1 Young's modulus, E

The Young's Modulus (E) is a measure of material stiffness and is therefore a key parameter in terms of hydraulic fracture propagation. Gale *et al.* (2007) quote values that can range from 4 to 61 GPa; which shows considerable variation. This variation may be related to variations in mineralogy. It is generally observed that as the clay and kerogen content decreases E will increase (Sone & Zoback 2013; Josh *et al.*, 2012). A high silica or carbonate content is likely to result in a higher E (Jarvie *et al.*, 2007; Ding *et al.*, 2012). High values of E are likely to result in longer fracture lengths, as found by a study on the Woodford Shale by Tran *et al.* (2014).

Josh *et al.* (2012) conducted two laboratory experiments on two separate facies, one with high clay content (~60%) and no obvious laminations and another which had a moderate clay content and a more well-developed fabric. The shales had an E value of 1-3 GPa and 9-11 GPa respectively. This highlights the role that clay content and fabric can have on the elastic moduli, however this study did not investigate properties perpendicular and parallel to the bedding. Sone & Zoback (2013) showed that the anisotropy of *E* increases with the clay and kerogen content. Despite the importance of *E* in terms of fracture propagation there is a relatively small amount of data openly available.

4.5.2.2 *Poisson's ratio, v*

The Poisson's ratio is a measure of translation of strain in one of the principal directions into the other principal directions. One correlation that can be made between this and the Young's Modulus is that they are negatively correlated. Therefore, brittle shale will have a low value for the Poisson's ratio. So the same principle applies with respect to mineralogy that a high brittle mineral content will result in a low Poisson's ratio (Rickman *et al.*, 2008; Tran *et al.*, 2014; Ross & Bustin, 2008).

There is a relatively small amount of values available for the Poisson's ratio of shale. Sone & Zoback (2013) do show, however, that *v* will exhibit a degree of anisotropy, with the greater values being generally parallel to bedding. There was, however, no obvious correlation between anisotropy and the clay and/or kerogen content.

4.5.2.3 *Shear modulus, G*

The Shear modulus (*G*) is a measure of the resistance to shear deformation. As stated previously, the predominant mode of fracturing that occurs during stimulation is tensional; however there may be an additional element of shear. Despite this fact there is a paucity of available values for *G*. It is, however, possible to calculate a shear modulus using values of *E* and *v*. The values of the elastic moduli reported in Gale *et al.* (2007) for the Barnett Shale and Austin Chalk give shear modulus values of 12.7 – 13.8 GPa and 17.1 – 21.8 GPa for each shale respectively.

Josh *et al.* (2012) state that many models often assume a constant value for the shear modulus, however it may be more likely to be anisotropic and heterogeneous throughout a shale formation. Sayers *et al.* (2015) and references within assign a shear modulus to the main mineralogical components, giving Quartz 44 GPa, Calcite 29 GPa, clay minerals 6 GPa and kerogen 3.2 GPa. This would therefore result in a heterogeneous distribution of the shear modulus as the mineralogy varies throughout the formation. Johri & Zoback (2013) assume a shear modulus of 30 GPa for their model, although the relationship of this assessment is unclear to the values calculated from Gale *et al.* (2007) and the values for the individual constituents. This illustrates that there is likely to be a high degree of variability in *G*.

4.5.3 Strength

A more direct approach to predicting the initiation of hydraulic fractures is the measurement of strength parameters. These can be recorded from true tensile tests, indirect tensile tests, or by compression tests. Ture tensile tests are rare in rocks, even more so in shale, with indirect or compression testing more common.

4.5.3.1 *Unconfined compressive strength, q_u*

The uniaxial compressive strength test (UCS) is a standard rock mechanics tests conducted on unconfined, prepared, core samples loaded axially until failure. The UCS test yields the unconfined compressive strength (q_u), which is used as a comparative parameter in most rock mechanics applications.

Josh *et al.* (2012) present data from a weak and a strong shale; they state that the weak shale would not be considered for shale gas exploration. The weak shale had a q_u of 8 MPa and had a clay content of approximately 60 % whereas the strong shale had a clay content of approximately 30 % and a q_u of 44 MPa. Davey *et al.* (2012) report values of 117 MPa and 136 MPa for the average q_u of the Montney Shale in two separate boreholes. Sone & Zoback (2013) inferred q_u using the internal angle of friction and intercept from triaxial tests. For samples of Barnett, Haynesville, Eagle Ford and Fort St. John shale q_u ranged between 100 and 250 MPa. A negative correlation between q_u and the clay and/or kerogen content and positive correlation between q_u and E was observed. It should be noted that considerable variation in q_u is reported by Josh *et al.* (2012), Davey *et al.* (2012) and Sone & Zoback (2013) for shale of between 8 and 250 MPa (a factor of 30). In terms of rock strength characterization (Waltham, 1994) shale would range from a weak rock to a strong rock.

Whilst the UCS test is a commonly performed test, it does not directly give insight into the hydraulic tensile properties of shale at depth. It does, however, show that strength is greatly variable in shale and that the pressure at which hydraulic fractures will form will greatly vary depending on the properties of the shale at the point of stimulation.

4.5.3.2 *Tensile strength, T_0*

The tensile strength may be considered one of the more important physical parameters of shale formations due to the tensile nature of hydraulic fractures. The tensile strength is traditionally calculated in the laboratory using the indirect tensile test, or Brazilian test. A cylinder of rock is loaded perpendicular to the long axis between two flat plates. Although compression is applied to opposite sides of the sample, this results in tensile stresses at the centre of the sample, resulting in the formation of a tensile fracture.

Sierra *et al.* (2010) present data from a shallow monitoring borehole which intersected Woodford Shale, the maximum depth being approximately 65 metres. Brazilian tests were carried out parallel and perpendicular to bedding, the results showed the tensile strength to be anisotropic and heterogeneous throughout the borehole. The perpendicular tensile strength was in the region of 10 – 15 MPa and 5 – 10 MPa parallel to bedding. The lower values were found to correlate to regions with a high clay and kerogen content. Sone & Zoback (2013) support this theory, stating shale with a high clay content are likely to have lower tensile strength. Slatt (2011) also report anisotropy in tensile strength, quoting 7.1 MPa and 12.6 MPa for parallel and perpendicular to bedding respectively. Areas of high clay content may be more likely to have a well-developed lamination due to the physical properties of clay minerals; these laminations are areas of weakness and may be contributing to a lower tensile strength.

Tran *et al.* (2014) present the same experimental data as Sierra *et al.* (2010) on the tensile strength of the Woodford Shale. However, they also compare the anisotropic values of the tensile strength with the carbonate content. A correlation is reported for tensile strength and carbonate content, although it should be noted that considerable variation is observed in the data that could be interpreted as showing no variation with carbonate content. Keneti & Wong (2010) also present anisotropy data for the Montney Shale, using samples from between 2,318 – 2,320 metres. Perpendicular strength ranged from 6 – 15 MPa whereas the parallel tensile strength ranged from 0.3 – 2.8 MPa.

Few published datasets are available for tensile strength in shale formations. Those reported above show a large variation between 0.3 and 15 MPa (a factor of 50), with considerable anisotropy of around 2 to 5. It is clear that anisotropy is strong in shale and it is expected that this will play a major role in the initiation and propagation of hydraulic fractures. The main controls on anisotropy are related to clay content and the degree of lamination of the shale. Fractures are likely to propagate in the direction of least resistance, so that may be likely to be parallel to bedding if the shale is strongly laminated.

4.6 The role of mineralogy

As shown above, mineralogy plays a considerable role on the initiation and propagation of hydraulic fractures in shale. The physics governing fracture and rupture are related to mineral bonds and therefore it is unsurprising that the mineralogy plays such a key role. Recent technological advances, especially in imaging techniques, now mean that it is possible to describe the microstructure of shale, which occurs at a micro- to nano-metre scale. X-ray Computer Tomography (CT), high resolution micro CT and dual beam Focused Ion Beam Scanning Electron Microscopy are imaging techniques which allow the pore system and petrology of shales to be described more accurately. Petrophysical approaches to shale gas reservoirs have been described by Jacobi *et al.* (2008) and Parker *et al.* (2009) using laboratory and wireline log-based methods to identify organic matter, porosity, permeability and mechanical properties. Rickman *et al.* (2008) combined mineralogy and geomechanics with petrophysics to optimise the hydraulic fracturing program; they concluded that this needs to be done for each shale separately due to the heterogeneous nature of shale. Britt & Schoeffler (2009) bring together the mineralogy (clay content) and geomechanical conditions of various producing shale formations to recommend mineralogical and elastic property cut off points, below which shale would no longer be considered prospective from a brittle fracturing perspective.

Despite these recent advances in techniques there still remains a large paucity in data which quantifies the rock mechanics properties that control the fracturing process. One of the major reasons for this limited data may derive from the difficulty in accessing quality, preserved core material for testing. Josh *et al.* (2012) consider this the most important issue with regard to experimental geomechanical testing in shale. This preservation of core material is essential to reducing uncertainty in experimental data through reducing the effects of drying, chemical & biological degradation and reduce the influence of de-stressing material prior to mechanical testing.

4.7 Knowledge gaps and recommendations

This chapter has described the state of understanding of the initiation of hydraulic fractures during stimulation. The following statements on current knowledge, knowledge gaps and recommendations can be made:

- Shale is a highly variable and heterogeneous material vertically and laterally. Both variability and heterogeneity need to be better understood and incorporated into numerical models to describe the behaviour of shale with respect to hydraulic fracturing.
- It is recommended that recovered core material from exploration wells is well preserved to maintain the stress state, reduce the effects of drying, chemical and biological degradation so that consistent datasets can be recorded, which should allow correlation of parameters to be determined.
- A lack of relevant data exists for shale in North America recorded from well preserved core material. Research has been conducted using a number of approaches, this hampers comparison studies. It is recommended that full disclosure of experimental protocols and data be made.
- A complex stress field is created around deviated wells in shale. The complexity of stress can be described for a perfectly elastic medium, the complexity of shale variability and anisotropy need to be incorporated so that a better understanding of where fracture initiation is likely to occur.
- Little research has been conducted on the effect of perforation on the mechanical properties of shale; it is recommended that this is undertaken to understand fracture initiation in shales.
- Little research has been conducted on quantifying tensile and/or hydraulic fracturing properties in the laboratory; it is recommended that this is undertaken to understand shale behaviour during hydraulic fracturing (for example, to confirm relationships between composition and rock behaviour), and also to upscale understanding from the laboratory to reservoir-scale models.
- It is clear that mineralogy plays a major control on the initiation of fractures in shale. More research is required in order to quantify the influence of different mineral constituents on the overall mechanical properties of shale. A better understanding of where and how fractures are initiated is also required.

5 FRACTURE PROPAGATION

Chapter 4 introduced the mechanisms that dictate when hydraulic fractures are formed. This chapter discusses the mechanisms responsible for the propagation of the formed hydrofractures; what dictates how long a fracture is, which direction do fractures propagate, and how dense is the fracture network. Two methods can be employed to determine the propagation of hydraulic fractures; 1) the monitoring of hydraulic fracturing during shale gas exploration using microseismic methods, and 2) the study of natural hydraulic fractures.

Discontinuities can be thought of in terms of single microcracks, which are planar discontinuities, or a linkage of many jogs and sharp bends, which on an atomic scale are sharp severances of atomic bonds within the crystal lattice as shown by electron microscopy (Lawn, 1983). Larger scale discontinuities are created by the coalition of many microcracks. A macroscopic brittle crack is a discontinuity formed by a complicated rupture event that has cut a large number of grains, without significant prior deformation at a particular stress (Paterson, 1978). Thus, a discontinuity's initiation and growth depends on the initiation and coalition of microcracks.

5.1 Theoretical considerations

Generally hydraulic fracturing involves the following physical processes: mechanical deformation, induced by pressure change in fractures and pores; fluid flow within fracture and formation, including their interactions; fracture propagation; as well as proppant transport and settling inside the fracture (Zhou *et al.*, 2014). Any theoretical model needs to account for all of these aspects within a heterogeneous shale experiencing a heterogeneous stress-field.

Considerable effort has been afforded to hydraulic fracture growth in rocks in recent years, especially in shale gas formations. This has been aided by micro-seismic monitoring, which can observe the complexity of the fracture network that develops (e.g. Calvez *et al.*, 2007; Cipolla *et al.*, 2005; Daniels *et al.*, 2007; Fisher *et al.*, 2002; Maxwell et at., 2002; Warpinski *et al.*,1998). Progress has been made in developing numerical models to describe hydraulic fractures in recent years (e.g. Adachi *et al.*, 2007; Dean & Schmidt, 2009; Ji *et al.*, 2009; Lecamplon & Detournay, 2007; Liu *et al.*, 2015; Vandamme & Curran, 1989; Wu & Olson, 2013; Zhang & Jeffrey, 2006; Zhang & Ghassemi, 2011; Zhang *et al.*, 2007).

Many numerical approaches have been employed in order to investigate the initiation and propagation of hydraulic fractures; Mohammadnejad & Khoei (2013[1,2]) used the extended finite element method applied to a cohesive crack; Hamidi & Mortazavi (2014) used distinct element modelling; Weng *et al.* (2014) introduce a complex fracture network model; Ding *et al.* (2014) used a coarse grid technique; etc.

The above makes it clear that there is no universal mathematical approach to describing fracture initiation and propagation in shale, with researchers using different approaches.

With this in mind, this report will not outline a mathematical approach and will therefore only make general statements about the theoretical framework.

According to Griffiths (1921) energy balance, a crack will propagate, when the energy release rate equals the crack resistance force. This theory was advanced by Irwin (1958) who stated that a fracture will propagate at a critical stress, this can be referred to as the critical stress intensity factor. Each mode of fracturing has its own stress-intensity factor. In terms of the hydraulic fracturing process it is important to know the stress at which fractures in the shale will propagate and also the direction and magnitude of this crack growth. In classical fracture mechanics, the propagation of a fracture is controlled by the magnitude of fluid velocity near the fracture tip. The rate of propagation is controlled by the availability of water at the tip to create stress corrosion. The physical properties of the shale and the stress state of the particular shale will go a long way to governing the propagation of fractures.

At the crack tip in a rock, stress is concentrated and creates a process zone made up of small cracks. Coalescence of these small microfractures results in the formation of a macro-scale hydraulic fracture (e.g. Atkinson, 1987). Thus the fracture propagation criterion can be reduced to a stress-based criterion. If the effective stress (considering the influence of the pore pressure) exceeds the critical traction stress (tensile strength), then the cohesive energy is fully dissipated and the fracture propagates further (Carrier & Granet, 2012). The critical traction stress is the physical property of the rock formation and independent of the applied loading.

Once a microcrack has been initiated, propagation occurs in the direction that requires the least energy to fail. Mesoscopically, a fracture may appear to have propagated smoothly without stopping; microscopically, propagation is rapid and discontinuous, following many branches of microcracking (Engelder, 1992). Larger scale discontinuities require the more energy-efficient process of microcrack communication and linkage. Under purely tensile conditions, a single microcrack can propagate into a large discrete discontinuity that can rupture the whole rock, whereas failure in compression requires linkage of many extensional and shear cracks. At the tip of a microcrack, the concentration of stress results in the creation of many small microcracks in a non-linear process zone. Microcrack communication lengthens the features, and propagates the process zone into the rock mass in the direction of the maximum compressive stress trajectory. Several processes control or influence discontinuity propagation, including elastic strain accumulation, crystal-plastic processes, diffusion processes, phase transformations and reactions, and fluid processes. Hydraulic fractures continue to propagate until the stress-intensity at the fracture tip is lower than the critical stress intensity of the rock being fractured (e.g. Savalli & Engelder, 2005).

Several approaches have been proposed to quantify fracture width and/or length. One example is that of Haimson & Fairhurst (1967), who proposed an analytical solution for fracture width given by:

$$W_{max} = \frac{4(1+v)}{3E} L\left(\sigma_3 + u_f\right)[2(1-v) - \alpha(1-2v)] \qquad \text{Eq. 12}$$

where W_{max} is the maximum fracture width, L is the fracture length, u_f is the pore pressure at failure, v is Poisson's ratio, E is Young's modulus, σ_3 is the minimum principal stress, and α is the Biot coefficient. This solution suggests that fracture width and length are proportional to one another. The width of propped fractures not only depends on the length of the fracture, but also on the amount of sand that is pumped (Khanna *et al.*, 2014).

5.2 Observations of natural hydraulic fracturing

Richard Davies and co-workers (Davies *et al.*, 2012) published a study on natural hydraulic fractures, which is useful in assessing the geometric extent of induced or stimulated hydraulic fracturing.

Cosgrove (1995) showed that natural hydraulic fractures can be observed in outcrops from the centimetre to metre scale. There are several types of natural hydraulic fracture that have all been extensively studied, including: injectities (e.g. Hurst *et al.*, 2011), igneous dykes (e.g. Polteau *et al.*, 2008), veins (e.g. Cosgrove, 1995), coal cleats (e.g. Laubach *et al.*, 1998), and joints (e.g. McConaughy & Engelder, 1999). Savalli & Engelder (2005) showed that growth of natural hydraulic fractures could be studied in the Devonian Marcellus formation in the US on the basis of plume lines that occur over a range of scales from centimetre to metre scale. The formation of these natural features is inferred to derive from gas diffusion and expansion within the shale during multiple propagation events.

The tallest example of natural hydraulic fracture result when they cluster and form chimneys (also termed pipes or blowout pipes). These have been observed to extend vertically for hundreds of metres (e.g. Cartwright *et al.*, 2007; Huuse *et al.*, 2010). Their origin is uncertain, but may result from critical pressurisation of aquifers and hydrocarbon accumulations (Zühlsdorff & Spieß, 2004; Cartwright *et al.*, 2007; Davies & Clarke, 2010). Chimney development may be followed by fluid driven erosion and collapse of the surrounding rock (Cartwright *et al.*, 2007). The release and expansion of gas from solution during advective flow may also play a role in development (Brown, 1990; Cartwright *et al.*, 2007). Chimneys are clearly identifiable in seismic data as vertical aligned discontinuities in otherwise continuous units (Cartwright *et al.*, 2007; Løseth *et al.*, 2011). Davies *et al.* (2012) examined 368 chimneys from offshore Mauritania and showed that the average height was 247 metres, with the tallest chimney being 507 metres. In offshore Namibia 366 chimneys showed an average height of 360 metres, with the tallest being approximately 1,100 metres. In offshore Norway 466 chimneys showed an average height of 338 metres, with a maximum of 880 metres. From comparing natural with induced hydraulic fractures, Davies *et al.* (2012) conclude that the probability of an induced hydraulic fracture extending vertically more than 350 metres is about 1 %. It should be noted that their conclusion is based on fracture height statistics alone and the mechanistic basis for fracture height control is not taken into account.

Hydraulic fracture stimulation from a horizontal borehole is usually carried out in multiple stages with known volumes and compositions of fluid (e.g. Bell & Brannon, 2011). Rather than chimney formation, clustering of fractures commonly occurs along planes, which are theoretically orthogonal to the least principle stress direction. Therefore fundamental differences exist in the geometry of these fracture systems compared to those that cluster to form chimneys, the reasons for which are not yet understood (Davies *et al.*, 2012).

5.3 Observations of hydraulic fracturing during shale gas exploitation

Much of the research conducted on hydraulic fracture propagation in shale derives from modelling and interpretation of microseismic data from active shale gas plays. This type of data is recorded by geophones and tiltmeters, which are placed in shallow monitoring boreholes close to the active well. Microseismic data allow reservoir engineers to map where deformation has taken place. This data can be used to tailor the fracturing process to ensure safety and to maximize gas output. Microseismic data also allow geomechanical properties to be inferred for the shale and can be used to ascertain the stress regime around the borehole.

5.3.1 Fracture height

Fisher, King and Warpinski (Fisher & Warpinski, 2011; King, 2012) have published the most comprehensive research on observations of hydraulic fracturing during shale gas exploitation. They used microseismic data from thousands of fracture treatments carried out on the Barnett, Woodford, Marcellus and Eagle Ford Shale formations; these being some of the highest producing formations in North America. The largest vertical fracture observed had a vertical extent of 1,500 feet (457 metres[4]) and occurred in the Marcellus shale. The largest mapped fractures tended to occur at the greatest depths. Fisher & Warpinski speculate that these are associated with the interaction with natural fractures. They observed that fractures grow much taller in the Marcellus than in the Barnett.

Fisher & Warpinski (2011) present tiltmeter data from more than 10,000 fractures and examine the vertical and horizontal components of these fractures. The overall pattern is that fractures shallower than 4,000 feet (1,200 metres) are predominantly vertical whereas below this point the ratio between vertical and horizontal fracture growth is more complex. Fisher & Warpinski (2011) discuss these patterns and conclude that the *in situ* stress and mechanical properties of the stratigraphy, such as variations in moduli and anisotropy associated with laminations, are the reasons why vertical fractures are hindered and lateral fracture growth is the preferred path of least resistance. Outside factors such as large faults in the area can lead to an increase in vertical fracture growth. This complex data set goes to show the complexities associated with fracture development and the mechanics driving fracture propagation in a heterogeneous layered rock.

[4] Davies et al. (2012) report 588 metres in Barnett shale.

Environmental concerns have been aired about the possibility of fracture growth vertically from a shale unit to overlying potable water aquifers. Fisher, King and Warpinski (Fisher & Warpinski, 2011; King, 2012) present data showing the depth of hydraulic fracturing, the maximum height of vertical fracture formation, and the deepest depth of potable aquifers for the Barnett, Eagle Ford, Marcellus and Woodford Formations; this data is summarized in Table 6. This data clearly shows that during 10,000 hydraulic fracture stimulations, the closest a vertical fracture came to the bottom of a potable aquifer was 2,800 feet (853 metres). Typically the distance was in the range 3,800 to 7,500 feet (1,158 – 2,286 metres).

Shale	Fracs number with micro-seismic data	Primary pay zone depth range	Typical water depth (and deepest)	Typical distance between top fracture and deepest water	Closest approach of top of frac in shallowest play to deepest water
Barnett	3,000+	4,700’ to 8,000’	500’ (1,200’)	4,800’	2,800’
Eagle Ford	300+	8,000’ to 13,000’	200’ (400’)	7,000’	6,000’
Marcellus	300+	5,000’ to 8,500’	600’ (1,000’)	3,800’	3,800’
Woodford	200+	4,400’ to 10,000’	200’ (600’)	7,500’	4,000’

Table 6 – Fracture height-growth limits in 4 major US shale plays (King, 2012)

5.3.2 *In situ* stress

Microseismic and tiltmeter data can be used to infer the *in situ* stress conditions within the target shale. Busetti and co-workers (2014[1,2]) use multi-array seismic data from the Barnett shale to determine the geomechanical conditions at the time of hydraulic fracturing. The locations of the microseismic outputs are often shown in a cloud map. The majority of fractures in this data set seemed to have propagated parallel to one another. The direction of these fractures was seen to be perpendicular to the minimum principal stress in the expected direction of the maximum principal stress (σ_1), meaning Mode I fractures. Some fractures were inclined to σ_1 suggesting natural fractures in the area may have also had a control over the fracture network.

5.3.3 Arrest and containment of fracture propagation

The physical properties of shale also have an effect on the arrest of propagation as well as the propagation. Smart *et al.* (2014) used finite element modelling to simulate the effect of mechanical stratigraphy and other varying geological properties, such as stress state and the presence of naturally occurring faults. The model is based on a log of the Ernst Member of the Boquillas Formation in Western Texas; this is a stratigraphic equivalent of the Eagle Ford Formation. The varying strengths of the beds, which were identified by the Schmidt-Hammer technique, were used to represent a realistic stratigraphy. The model simulated fluid injection and predicted where fractures were likely to form. Several iterations of the model were presented showing the varying effects of stratigraphy and mechanical properties. They conclude that mechanical stratigraphy can exert a fundamental control on the pattern of hydraulic fracturing and only small variations in this stratigraphy can result in large changes in the observed fracture pattern. Although this model is only two dimensional it predicts that the fracture pattern will be complex, with propagation in many directions and interconnectivity of the fractures. It must be noted that this study used just one value for the Young's Modulus and Poisson's ratio, when it is likely that this would be heterogeneous. Laboratory measurements may be required to constrain this model further so that the mechanical stratigraphy is better represented.

Philipp *et al.* (2013) combined field investigations and numerical modelling to conclude that heterogeneous stratigraphy can result in strata bound fractures. These fractures are more likely to be strata bound if the boundary between strata is abrupt as opposed to a gradual change in mineralogy. Philipp *et al.* (2013) also state that strata with contrasting mechanical properties are also differently stressed, as a result of remote tension or compression, excess pore pressures or local stress from propagating hydro-fracture tips (Zang & Stephansson, 2010). Variations in horizontal stresses are common within petroleum reservoirs (Economides & Nolte, 2000). These heterogeneous local stress fields can act to control the propagation of hydraulic fractures. However, Philipp *et al.* (2013) also state that as a network of hydraulic fractures develop in an area during the extraction process then the area may become more heterogeneous, resulting in a multi-layer system gradually becoming a single layer system and acting as one; meaning that it is only the mechanical stratigraphy which effects the initial hydraulic fracture emplacement.

As well as using microseismic data to predict fracture propagation in shales, laboratory experiments can also be used to examine fracture properties. The fracture toughness is a measure of a materials resistance to tensile fracture propagation. The fracture toughness can quantify the stress concentration at a crack tip at the point of fracture propagation. Fisher & Warpinski (2011) suggest the heterogeneous nature of shale results in varying fracture toughness values which can act to halt fracture propagation. This theory is supported by laboratory fracture toughness data of the Woodford Shale which shows values in the upper Woodford shale to range from 1.15 to 1.17, whereas in the Lower and Middle Woodford Shale values range from 0.65 to 0.74. A higher quartz content is observed in the Upper Woodford shale, meaning the fracture toughness may be influenced by mineralogy. Therefore, not only does fracture toughness play a role in fracture initiation, it plays a controlling role in fracture propagation and arrest. Chandler *et al.* (2012) investigated the fracture toughness of Mancos Shale using a modified Short Rod method, which involved the propagation of a crack through a triangular ligament in a chevron notched cylindrical sample (Ouchertlony, 1988). Fracture toughness was measured in three directions to investigate anisotropy. A substantial anisotropy was observed, with values 25 % higher in one direction. They also noted that the values recorded in this experimental set up are 1.5 – 2-1 higher than other published results, implying the material also varies within the formation.

5.3.4 Hydraulic fracture characterization

Despite a wealth of data on microseismic observations and the corresponding modelling of these, little is known about the actual characteristics of the hydraulic fractures; such as fracture density, topography and width. These are all important characteristics which would allow reservoir engineers to more accurately predict production levels. In absence of this information, many studies have used a description known as the Specific Reservoir Volume (SRV) to describe the volume of rock which has been affected by the injection of the fracturing fluid (Mayerhofer *et al.*, 2006; 2008). This is deduced from the spread of microseismic data and assumes that all of the seismic outputs are associated with connected fractures. Recent studies have begun to attempt to improve the calculation and interpretation of the SRV as these assumptions do not give enough information on the fracture network and connectivity (Yin *et al.*, 2015; Cipolla & Wallace, 2014).

5.3.5 Physical properties

Maxwell (2011) studied microseismic data from the Montney shale and correlated these to geophysical measurements of the rock. They notice a higher number of microseismic responses in areas with lower Poisson's ratio, they also note that the density of microseismic responses may be used to estimate a produced fracture density. This type of information can be used to better focus the injection of fracturing fluid to areas which are likely to form a higher fracture density.

5.4 Concluding remarks on fracture propagation

Fisher & Warpinski (2011) highlight the need to understand the geology surrounding the target area in order to estimate the direction of fracture propagation. Their concluding remarks clearly asses the current state of understanding:

> *"The directly measured height growth is often less than that predicted by conventional hydraulic-fracture propagation models because of a number of containment mechanisms….Some of those mechanisms include complex geologic layering, changing material properties, the presence of higher permeability layers, the presence of natural fractures, formation of hydraulic-fracture networks, and the effects of high fluid leak-off."*
>
> *"Fracture physics, formation mechanical properties, the layered depositional environment, and other factors all conspire to limit hydraulic-fracture-height growth, causing the fracture to remain in the nearby vicinity of the targeted reservoirs."*

5.5 Knowledge gaps and recommendations

This chapter has described the state of understanding of the propagation of hydraulic fractures during stimulation. The following statements on current knowledge, knowledge gaps and recommendations can be made:

- Shale is a highly variable and heterogeneous material. Both variability and heterogeneity need to be better understood and incorporated into numerical models.
- Many numerical approaches exist; modelling should work towards a unified approach of describing fracture propagation in shale.
- Numerical models tend to over-predict the length of hydraulic fractures that are formed. The understanding of fracture arrest in a complex geological unit, such as shale, needs to improve to better numerically represent the hydraulic fracturing process.
- Experimental observations are needed on fracture propagation in a complex, layered shale in order to identify the controls of fracture deviation and/or arrest.
- A better understanding of the mineralogical control on fracture propagation is required.
- Shale does not behave as a perfect elastic medium and as a result numerical models need to incorporate the full thermo-hydro-mechanical-chemical behaviour of the rock. This is, however, currently computationally time consuming.
- A close relationship is required between drilling engineers, experimentalists and numerical modellers in order to improve the understanding of a complex system.
- Many studies have been conducted that consider shale as a uniform, homogenous, elastic material. Whilst complexity is difficult to incorporate within numerical models, representative physics is required with good ground truth field data.
- A wealth of empirical field observations in North America is now available that should help to improve the understanding of the physics controlling fracture propagation.
- Modelling scenarios are required on European shale using well constrained approaches demonstrated in the United States to predict the behaviour of European shale plays.

6 INDUCED VERSUS NATURAL FRACTURES

This chapter examines the inter-play of the pre-existing fracture network found in natural shale units and the induced hydrofractures created during hydraulic fracturing. As introduced in Chapter 5, one of the limitations of fracture propagation theory is that it does not always take into account the natural fractures found in shale formations at a range of scales. These features may act as conduits for the hydraulic fracturing fluid, or stress perturbations that influence the fracture propagation direction. Whether fracture interplay results in fluid loss or influence fracture propagation direction, knowledge of induced versus natural fractures is vitally important.

In terms of shale gas exploration, the interplay of induced and natural fractures is desired as it leads to a complex fracture network that promotes gas extraction. In terms of regulation, knowledge of the interplay of natural and induced fractures is vital in order to ensure the shale unit is not breached, which might lead to leakage of hydraulic fracture fluid.

Hydraulic fracturing in shale gas reservoirs has often resulted in complex fracture network growth, due to promoting the propagation and connection of natural fractures, as evidenced by microseismic monitoring (Liu *et al.*, 2015). It has been studied extensively by researchers from different aspects: Gale *et al.* (2007) studied the importance of natural fractures on hydraulic fracture treatments; Zhao *et al.* (2012) presented new insight into fracture network generation in reopening and slippage of natural fractures; Yu *et al.* (2014) performed a sensitivity study of gas production for a shale gas well with different geometries of multiple transverse hydraulic fractures; and Olson *et al.* (2009) and Rahman & Rahman (2013) investigated fracture propagation behaviour in the presence of natural fractures.

6.1 Natural fractures

The natural fractures in a shale can be defined by their geometric properties (e.g. width, length, spatial distribution, orientation), fluid properties (e.g. porosity, permeability) and their physical properties (e.g. fracture fill and fracture roughness). Describing all of these properties by using borehole data alone is very difficult, therefore observations from wells are often combined with field observations. Gale *et al.* (2014) conducted an extensive field and borehole study of the natural fractures in many of the shale gas prone shale units in North America. Their approach was to compare and contrast the properties of the fractures and look for correlations between the shale formations.

The most common natural fracture Gale *et al.* (2014) describe are sub-vertical and have formed perpendicular to the bedding plane; some were seen at 70 – 80^{o} to the bedding plane. These fractures often terminated against bedding layers or intersected other structures within the shale. Much of this data came from core, so Gale *et al.* (2014) describe the fractures in terms of the number of vertical fractures per 100 ft (30.5m) of vertical core; this number varies from 7 to 160 per 100ft (1 fracture per 0.2 to 4.4 metres). In some cases, a correlation was observed between high fracture density and mineralogy; for example the Forestburg Limestone had a very high carbonate content and a high fracture density, whereas the Marcellus Shale has a high clay content and a low fracture density. Zeng *et al.* (2013) measured fracture density in the Longmaxi Shale Formation in China and found that fracture density positively correlated with total organic carbon (TOC), however for the Niutitang Shale fracture density negatively correlated. Zeng *et al.* (2013) argue the Longmaxi shale has a positive correlation with TOC due to the thermal evolution of organic acids which have dissolved carbonate and feldspar, which has increased the porosity and also the susceptibility to fracture under external forces. Zeng *et al.* (2013) suggest that mineralogy, such as brittle mineral content, acts as the predominant control on fracturing. Fracture density will also be controlled by large-scale tectonic structures, which are areas of high deformation; for instance folds and thrusts are more likely to have a higher fracture density (Zeng *et al.*, 2013).

Gale *et al.* (2014) report that the fracture aperture of the observed sub-vertical fractures ranged from 30 μm to 10 cm, however the large majority of these fractures were between 30 μm and 1 mm. Furthermore, the fracture heights varied from < 1 cm to 1.8 metres. It has to be noted that these lengths were recorded from core and that the fractures may have extended further. Many of the sub-vertical fractures were recorded in detail; however, as they were measured from narrow bore core it was not always possible to analyse the fracture tips to examine the mechanisms that arrested fracture propagation.

Zeng *et al.* (2013) reported observations on natural fractures in core material from China. Only 2.5 % of the fractures terminated abruptly by stratigraphy, 26.5 % gradually tapered to a stop, while 71 % of the fractures ended off the core. Therefore of the fracture tips that could be observed 8.6 % terminated abruptly by stratigraphy, while 91.4 % gradually tapered. Ferril *et al.* (2014) conclude that bed-scale compositional and textural variations in the Eagle Ford shale led to contrasting mechanical behaviour with regards to fracture propagation and length.

As described above, many of the gas producing shale formations in North America contain sub-vertical fractures. To form a highly conductive natural fracture network these fractures must be connected. Gale *et al.* (2014) also describe a set of fractures parallel to bedding, although these are not ubiquitous in all of their studied shale formations. These bedding parallel fractures were up to 15 cm wide and extended for tens of metres laterally (Rodrigues *et al.*, 2009). The fracture density of these bed-parallel fractures varied significantly throughout the same formation; for example the Vaco-Muerta Formation in Argentina contained just one bed-parallel fracture at outcrop scale at one location, whereas at another outcrop of similar size 100 bed-parallel fractures were described with thicknesses up to 5 cm.

Many of the fractures, both bed parallel and sub-vertical, described by Gale *et al.* (2014) were filled with calcite cement. Cemented fractures and faults give evidence for fluid flow within the rock, this may have occurred during diagenesis or during another part of the burial history. The most common cement to have been described is a fibrous calcite cement, although quartz filled fractures were also observed (Gale *et al.*, 2007; Montgomery & Jarvie, 2005). In the Barnett Shale, Gale *et al.* (2007) and Montgomery *et al.* (2005) state that all sub-vertical fractures were calcite filled. Montgomery *et al.* (2005) believe that the calcite filled cements are a barrier to fluid flow. However, Gale *et al.* (2007) oppose this as they state the low tensile strength of the cement and the fact that it is not in crystallographic continuity with the fracture walls means that it will be re-activated and therefore not a barrier to fluid flow (Zeng *et al.* 2013). Gale & Holder (2008) showed that calcite filled fractures have half the strength of intact rock. They also showed that quartz filled fractures in the Woodford shale are stronger than the host rock. Zeng *et al.* (2013) describe natural fractures in Niutang and Longmaxi shale from core material in China. They state that a high density of natural fractures will be beneficial to the hydraulic fracturing process even if filled with calcite cement, resulting in an increase of gas flow to the well.

The limited research summarized above shows that vertical fractures of varying density predominate in shale formations. Bedding-parallel fractures may also be present, but are not ubiquitous. The scale of the fracturing is variable, as is the mineralogy of cement infill. In certain cases this mineral infill can strengthen the host rock, whereas in others it is a mechanical weakness. There is evidence that geomechanical variations between facies within a shale formation can result in fracture arrest, although this is not the only mechanism that results in fracture termination. It is vital that similar comparisons are made with shale-gas prone formation in Europe to describe the expected natural fracture population.

6.2 Interaction of natural and induced fractures

The benefits, or not, of a natural fracture network for the hydraulic fracturing process are an area of current research and debate. Ferril *et al.* (2014) state that natural fractures can act to compartmentalise fluid pressure during the hydraulic fracturing process. This may result in the injected fracturing fluid flowing through the natural fracture network, resulting in the pressurized fluid being dispersed over a larger area thus reducing fluid pressure (leak-off). This may result in fluid pressure reducing below the tensile strength of the shale arresting hydraulic fracture propagation. However, the injection of a pressurized fluid into a naturally fractured volume may result in the reactivation of fractures if calcite cement is sufficiently weak. This could potentially result in an increase in flow of hydrocarbons through the natural fractured network towards the well.

Zhao *et al.* (2012) and Gale *et al.* (2007) have proposed a theory of how natural and hydraulic fractures may interact. When the initial hydraulic fracture from the well intersects a natural fracture, it will form two left and right branches. These branches will propagate along the natural fracture, until they reach the crack tip, at which point they will change direction and propagate in the direction perpendicular to σ_3; as shown in Figure 9. This process can continue until the fluid pressure within the fractures is less than σ_3. If a shale formation has a complex natural fracture network, the injection of hydraulic fluid is likely to only 'activate' this network, as opposed to producing a complex network of fractures.

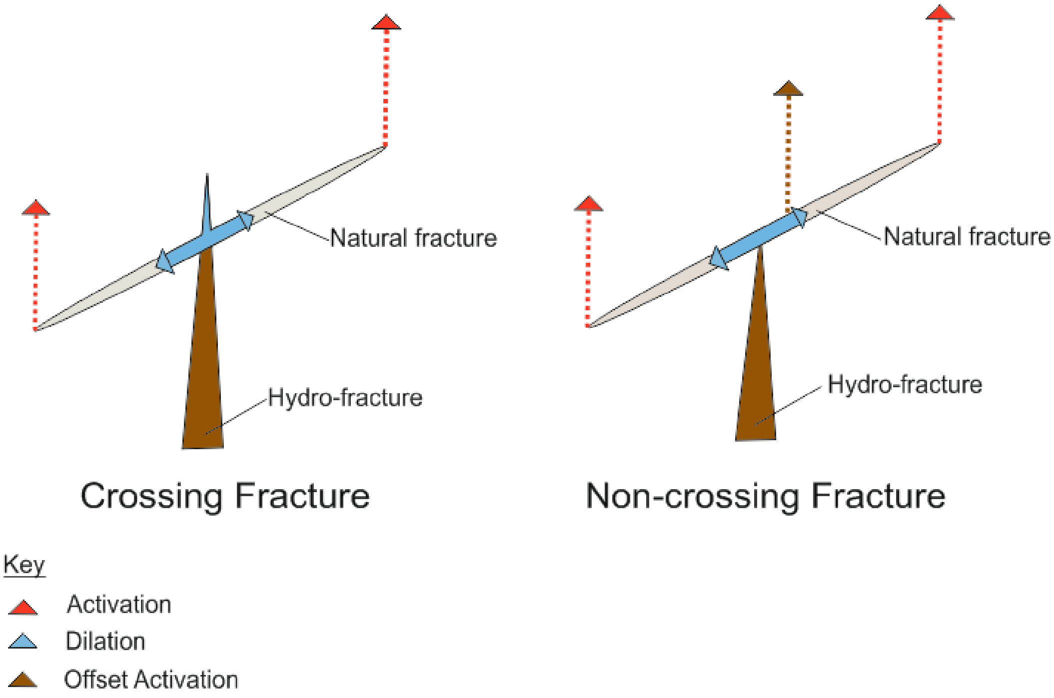


Figure 9 – Representation of the interaction of natural and induced hydrofractures in shale gas operations.

6.3 Microfractures

At a smaller scale to the natural fractures discussed above, microfractures within shale formations may play an important role in fracture propagation. Lockner *et al.* (1992) showed that before a rock fails there is an increase in microcracks which coalesce to form a larger failure plane; therefore meaning a high abundance of microcracks may mean that it is easier for a failure plane to develop during the hydraulic fracturing process. Pitman *et al.* (2001) showed bed-parallel microfractures in the dolomitic siltstone of the Bakken Formation and Capuano (1993) found microfractures in Oligocene Frio Formation shale.

Microfractures form due to the actual splitting apart of the rock fabric in the direction of least resistance, i.e. perpendicular to the minimum in-situ stress direction or least principal stress. Since shale can be described as a multi-phase and multi-scale sedimentary rock mainly composed of clay platelets surrounding inclusions of other, stiffer minerals (e.g. quartz, calcite, and/or pyrite) or more compliant organic phases (kerogen), local density contrasts are very likely to occur. In fact, microfracturing may be the rule rather than the exception (Vernik, 1993, 1994; Vernik & Liu, 1997; Lash & Engelder, 2005; Padin *et al.*, 2014). It could arise from the internal production of fluids by the organic matter decay or the dehydration of clays (shrinkage processes); in that case, microfractures are expected to be predominantly parallel to the bedding plane (e.g. Harrington & Horseman, 1999; Keller *et al.*, 2011; Jiu *et al.*, 2013). Several studies have demonstrated that microfracture populations correlate to the shale content of brittle minerals, such as quartz, calcite, dolomite, and/or feldspar (e.g. Nelson, 2009; Hill et al, 2002; Nie *et al.*, 2009 ; Li, 2009; Ding *et al.*, 2012; Zeng, 2013). The presence of microfractures mostly relies on the combination of many factors through the shale history.

It has been observed that the finer the grain size, the more conducive the shale matrix will be to fracture development, providing shales with similar mineral compositions (Zeng & Xiao, 1999; Li *et al.*, 2009). However, if natural fractures are known to have a positive impact on the permeability of a shale formation (e.g. Decker, 1992; Gale *et al.*, 2007, 2014; Ding *et al.*, 2012; Zeng *et al.*, 2013), the role of microfractures on shale permeability seems to be more complex. Padin *et al.* (2014) argue that the microfracture network also acts as permeable pathways when fluid pressure is increased, Zeng *et al.* (2013) argue that it will also be extremely unfavourable to the preservation of hydrocarbons. After microfracture formation, fluid flow may occur allowing the precipitation of minerals, which may seal them; fully filled (micro)fractures will act as fluid barriers (Warpinski & Teufel, 1987).

Gale *et al.* (2014) hypothesize a power law relationship for fracture width and length, using data from the Marcellus Shale and Austin Chalk. If this power law is extrapolated into the microfracture domain, the average spacing for fractures would be approximately 0.1 to 1m. Thus the paucity of microfracture data may be due to the low probability of microfractures being captured in core samples. The presence of microfractures in shale formations and their influence on hydraulic fracture propagation is poorly understood and represents a gap in understanding. Moreover, since elastic properties evolve with the scale and damage, any upscaling procedure is challenging despite the crucial contribution of microfractures to the fracture formation.

6.4 Conclusions on induced vs natural fractures

Natural fractures and microfractures may represent planes of weakness within natural shale formations. It is likely that the density and orientation of these features will influence fracture propagation. Thus, the interaction between natural fractures and hydraulic fractures is a key area of research. Natural fracturing will be controlled by current and historical tectonic stresses and mineralogy. Mineral infill of geological fractures also has a control on whether natural fractures influence hydraulic fractures or not. Therefore an increase in knowledge of natural fracture properties, the stress regime, the role of mineralogy, and the interaction of natural and induced hydrofractures is required to better understand the potential stimulated reservoir volume.

6.5 Knowledge gaps and recommendations

This chapter has described the state of understanding of the interaction of induced hydraulic fractures and the natural fracture/microfracture network within shale. The following statements on our current knowledge, knowledge gaps and recommendations can be made:

- In order to predict the influence of natural fracture populations on hydraulic fracture propagation it is vital to understand the natural fractures. Limited studies have been conducted on natural fractures at depth and this represents a clear gap in our understanding.
- Discontinuities occur on a range of scales, from microfractures through to regional scale faults. The influence of these features on hydraulic fracture propagation needs to be better understood.
- The presence of microfractures in shale formations and their influence on hydraulic fracture propagation is poorly understood and represents a gap in our understanding.
- Generally, vertical fractures of varying density predominate in shale formations. Bedding-parallel fractures may also be present, but are not ubiquitous. Therefore a better understanding of the full three-dimensional orientation of fracture sets and the influence this has on fracture propagation and arrest is required.
- Mineral infill within fractures may act to either strengthen or mechanically weaken the host rock. A full assessment of the role mineralised fracture fill has on mechanical strength is needed.
- Fracture population studies need to be conducted for European shale plays and these need to be carefully assessed based on North American experiences.
- The full 3-dimensional description of natural and hydraulically induced fractures is required. This needs to include data on fracture roughness/topology, aperture, length, and extent.
- Numerical models of fracture propagation need to take into account shear movement that occurs along natural fractures when they are reactivated during stimulation.

7 ENGINEERING CONSIDERATIONS

This chapter discusses the knowledge of drilling engineering and review the understanding of how drilling operations can influence the pattern and extent of hydraulic fractures. This chapter will draw on the operational considerations introduced in Chapter 2 and the theory introduced in all chapters.

7.1 Hydrofractured zone extension

The hydrofracture zone is simply the gross volume of rock at depth that contains fractures generated by the hydraulic fracture stimulation. A shale gas operator will begin by designing a hydrofracture zone based on a given numerical model, or based upon local experience. The zone will be dependent on parameters including hydraulic fracture volume and pressurization rate. The early stage of hydraulic fracture stimulation (i.e. during the first few stages of hydraulic stimulation) will be aimed at validating and/or calibrating the hydrofracture zone model. This can be done using micro-seismic analysis or tilt meters for direct traces; or indirectly using pressure build up, production tests or interference tests (Fisher *et al.*, 2004; Fix *et al.*, 1991; King, 2012; King & Leonard, 2011; Woodroof *et al.*, 2003). Considerable understanding can also be obtained from analysis of core recovered from drilling.

Considerable understanding of the hydrofracture zone has come from microseismic monitoring. Excellent signal strength and high amplitude microseismicity has led to increased precision with respect to the event locations (Detring & Williams-Stroud, 2012). Microseismic mapping demonstrates that an interconnected fracture network of moderate conductivity with a relatively small spacing between fractures is achievable by hydraulic fracturing (Warpinski *et al.*, 2009). The subsequent production from these reservoirs supports both the modelling and the mapping.

Maxwell *et al.* (2011) present results from microseismic measurements integrated with seismic reservoir characterization and injection data to investigate variability in the hydraulic fracture response between three horizontal wells in the Montney shale in NE British Columbia, Canada. Microseismic events occurred from 200 to 1,200 m away from the point of injection (source site). It was observed that hydraulic fractures tended to be asymmetric and grew preferentially towards the low Poisson's ratio region of the shale unit. This is attributed to material property changes and associated lower stresses in these regions.

Since the start of injection of brine into a single deep injection well in 1991 in Paradox Valley, Colorado, earthquakes have been repeatedly induced (Yeck *et al.*, 2015). The induced seismicity separates into two distinct source zones: a principle zone (> 95% of the events) asymmetrically surrounding the injection well to a maximum radial distance of ~3 km, and a secondary, ellipsoidal zone, ~2.5 km long and centered ~8 km northwest of the injection well. Within the principal zone, hypocenters align in distinct linear patterns, showing at-depth stratigraphy and the local Wray Mesa fracture and fault system. The primary faults of the Wray Mesa system are aseismic, striking subparallel to the inferred maximum principal stress direction, with one or more faults, probably acting as fluid conduits to the secondary seismic zone. Individual seismic events in both zones do not discernibly correlate with short-term injection parameters; however, a 0.5 km^2 region immediately northwest of the injection well responds to long-term, large-scale changes in injection rate and the surpassing of a threshold injection pressure. In addition, the fault planes are consistent with principal stress directions determined from borehole breakouts (Yeck *et al.* 2015). This illustrates the complex response of a naturally fractured geological unit to changes in reservoir pressure.

7.2 Hydraulic fracture fluid

Hydraulic fracture fluid plays a vital role in the formation of hydraulic fractures. Fisher *et al.* (2004) examined microseismic monitoring results and found that hydraulic fractures propagate in both horizontal and vertical directions in complex patterns rather than single symmetric patterns. They also noted that a larger volume of fracturing fluid leads to a wider area swept by microseismic events and a higher gas yield. This suggests that a limit can be imposed on fracture propagation based on the volume of fluid injected. It may be theoretically possible to create a pressure that could overcome geological stresses so that a fracture could grow vertically to shallow depths or even the surface. However, this is not feasibly practical. During fluid injection a certain amount of leak-off is experienced, this is caused by fluid flowing into the shale gas unit or entering natural fractures and is pressure dependent. Different shale types will result in variations in leak-off. In order to create such an enormous hydraulic pressure that a fracture would propagate significant distances there would become a point where injection rate would equal leak-off and therefore the fracture could simply not grow any further (King, 2010; Fisher & Warpinski, 2012; Mair *et al.*, 2012).

Flewelling *et al.* (2013) performed a fracture height study based on a simple energy balance. In order to hydraulically fracture shale, energy is needed to (1) counteract the least principal stress; (2) displace and open the walls of the fracture; (3) propagate the fracture at the fracture tip; and (4) counteract energy dissipation due to fluid viscosity and leak-off of fluid pressure. Flewelling *et al.* compared end-member situations for given pore fluid pressure, Young's modulus, and fracture aspect ratio with data from 1,754 individual shale gas and tight rock conventional wells. This showed that the maximum fracture height is linked to the volume of the hydraulic fluid injected. All microseismic data showed the maximum observed fracture length was 600 metres, with the majority of heights much less than this.

King (2012) discussed leak-off and its role on arresting fracture growth. The rate of leak-off was seen to correlate with the maximum fracturing network possible in the formation. The formation contact area that the fracturing fluid creates is normally very large and is about 10,000 to 100,000 m^2 in a densely, naturally fractured shale well. This volume usually has a total extent of 30 metres away from the wellbore.

The observations above suggest that the extent of fracturing is strongly correlated with the volume of hydraulic fracturing fluid injected. Therefore, this suggests that maximum fracture heights can be controlled by the volume of fluid used.

7.3 Pressurization rate

As stated above (Section 7.2) the rate of fluid pressurization has a theoretical maximum related to the leak-off rate of the geological formation. This suggests that fluid pressurization rate has a role in hydraulic fracture formation.

Zhao *et al.* (2012) present a theoretical study of pressurization rate on the interaction between induced and natural fractures. They discuss the linkage of natural fractures at their tips during hydraulic stimulation to create a fracture mesh. This research suggests that a critical pump pressurization rate is required to form an intensive fracture mesh. This critical pump rate varies as the angle between the natural fractures and the stimulated fractures varies; with a minimum achieved if natural fractures are perpendicular to the well. The critical pump rate is also dependent on the natural fracture length and the elastic properties of the shale. Whilst this research is purely theoretical, it suggests that the formation of a well-developed inter-connected fracture network during hydraulic stimulation is dependent on the pressurization rate of the fracture fluid.

Bing *et al.* (2014) present results from a laboratory study simulating hydraulic fracturing down a scaled borehole in a cubic sample of shale. The experimental study simulated field injection rates of between 9 and 16 m^3/min. It was observed that difficulty occurred in generating hydraulic fractures at low injection rates. At the highest injection rates the formed fractures were more complex, but did not necessarily result in a greater volume of the rock being fractured. The highest pressurization rate leads to pressure build-up, which results in greater energy loss and insufficient time for filtration to reduce the strength of the shale. Variable injection rates were seen to increase the likelihood of interaction between induced fractures and the naturally occurring fracture network. Generally a high injection rate is required to maintain open propagation of fractures and to ensure they remain open. This experimental study showed that an injection rate of 10 m^3/min and a viscosity of 10 mPa.s are optimal if using constant rate pressurization. It should be noted that there is a maximum rate that the fluid can be pumped; this is dependent on the power of pump trucks and the diameter and length of the well.

7.4 Hydraulic fracture design

Considerable effort has been afforded in recent years to improving the efficiency of hydraulic fracturing and to improve gas extraction from shale. This section discusses advanced hydraulic fracturing techniques.

The Texas two-step method (East *et al.*, 2010) is a hydraulic fracturing method that has been developed to take advantage of changes in minimum horizontal stress in response to fracture spacing as a result of stimulation in horizontal wells. The method is an alternating stimulation method, after creating the first and second interval a third is conducted between the first two. Each hydraulic stimulation alters the local stress field. Any change in stimulation sequence alters the stress in the area between fractures and activates the stress-relieved discontinuities. This can create a complex network of fractures connected to the main hydraulic fractures (Rafiee *et al.*, 2012). The Texas two-step uses the stress shadow from the previous fracturing treatment to increase the likelihood of transverse fractures forming. This method results in a complex network of conductive fractures close to the well with a high fracture surface area. Controlling hydraulic fluid volumes means that only the local rock-mass to the well is stimulated. This generates good gas yield with a reduced risk of hydraulic fractures propagating vertically through the shale sequence.

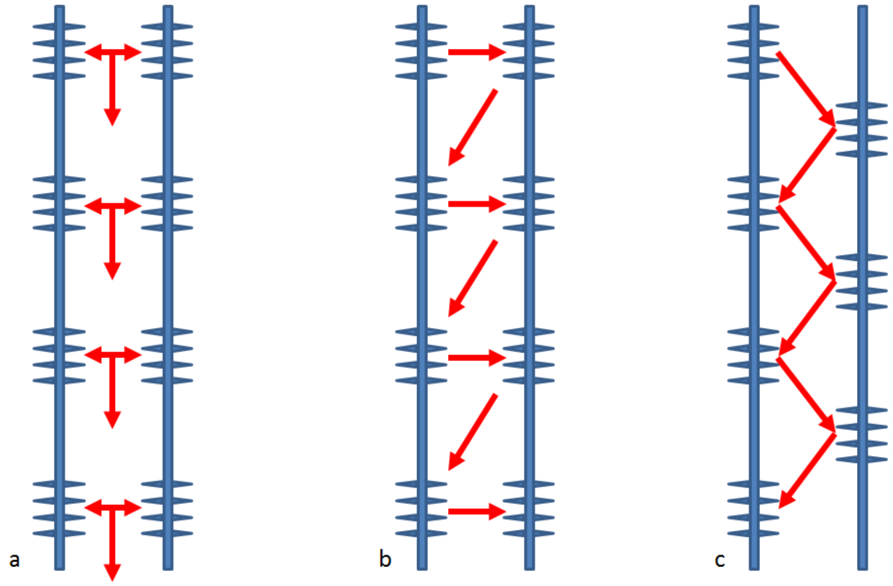


Figure 10 – Shale completion schemes using dual boreholes: a) simultaneous hydraulic fracturing; b) sequential hydraulic fracturing (zipper-frac); c) Modified zipper-frac. Re-drawn from Nagel *et al.*, 2013.

Waters *et al.* (2009) introduce the concept of simultaneous fracturing, in which two parallel horizontal wells are stimulated simultaneously. The stress perturbation created by simultaneously hydraulically fracturing in two boreholes results in the promotion of fractures propagating between the wells. When hydraulic fracturing intervals are directly opposite one another in the well, the technique is referred to as aligned fracturing, simultaneous fracturing or simul-frac (Figure 10a). A modification to this technique is the zipper-frac where the sequence of simultaneous hydraulic fracturing is shown in Figure 10b. This has been further developed into the modified zipper-frac, where a staggered pattern of stimulation occurs, as shown in Figure 10c. All of these techniques exploit the stress distribution around fractures and create a more complex fracture pattern (Rafiee *et al.*, 2012). In simul-frac, when the opposite fractures propagate toward each other, a degree of interference occurs between the tips of the fractures and forces the fractures to propagate perpendicular to the direction of the horizontal wellbore. Whilst the modified zipper-frac technique relies on stress interference caused by the middle fracture initiated from the other lateral.

Rafiee *et al.* (2012) proposed and modelled the modified zipper-frac technique. They showed that the technique creates a more complex fracture network without the operational issues observed in the other simultaneous hydraulic fracturing techniques. The complexity of the formed fractures is dependent on the spacing between the two parallel boreholes, with spacing expected to be between 150 and 300 metres. This modelling exercise showed that the stress interference between fractures can create an effective stimulated reservoir volume to enhance hydrocarbon production.

The examples introduced show that the use of dual boreholes has the potential to increase hydrocarbon return. A by-product of this is a complex fracture development in a restricted volume that occurs predominantly between the stimulated wells; thus containing the extent of the stimulated reservoir volume. However, the use of two wells increases costs and is generally used where an economic return is expected.

7.5 The role of proppants and additives

As introduced in Section 2.6, fracturing fluid normally consists of water with a range of additives to assist in the fracturing process and to increase the life of downhole infrastructure. Cuadrilla Resources Limited state that in the UK less than 0.05 % of the fracturing fluid is made up of chemical additives (Stamford & Azapagic, 2014). King (2012) states that friction reducer and biocide constitute the most common additives representing about 0.025% and 0.005-0.05% of the total volume respectively. As shown in Table 1, between 3 and 13 types of chemical additives are used in different mixtures depending on specific well conditions. Also added to the fracturing fluid is proppants, with the primary function of propping open hydraulic fractures once they have formed. These are made up of crush-resistant solid materials; commonly sand, but also ceramic beads, aluminium beads and sintered bauxite. Proppants remain suspended in the fracturing water with the aid of thickening agents. Generally, proppants constitute 1 – 10 % of the total fracture fluid volume. The thickeners, also called gelling agents or solidifiers, are chemicals used to increase the water's viscosity. The most common thickener is guar gum.

While there have been several studies looking at proppants and additives, there has been limited research into the role of additives and proppants on hydraulic fracture formation and the extent of the stimulated reservoir volume. Fluid viscosity is one factor that is used in predicting hydraulic fractures. As introduced above, Flewelling *et al.* (2013) state that energy is needed to counteract energy dissipation due to fluid viscosity and leak-off of fluid pressure during hydraulic fracturing of shale. The permeability of the host shale unit is also going to be viscosity dependent, which will dictate fluid leak-off. Therefore additives will play a role in the extent of hydraulic fracturing. The lack of open literature on the role of additives on fracture propagation is seen as a gap in current knowledge.

7.6 Geological considerations

Chapter 3 highlighted that the term “shale” covers a range of sedimentary rocks that have a large contrast in physical properties. Havens (2012) for instance, shows that the Bakken Formation has a wide range of elastic properties and has strong anisotropy. Hawkes (2015) showed variation in tensile strength with facies of the Bakken Formation, with averages for each of the 9 identified facies ranging in tensile strength from 6 to 16 MPa. The uniaxial strength of Bowland Shale in the UK has been shown to range from 62 – 91 MPa (de Pater & Baisch, 2011). Hence, considerable variability is seen within a geological sequence of shale.

Theory states that hydraulic fractures will grow in the direction of maximum stress. Field experience has shown that fractures tend to propagate upward until contact is made with a rock of different structure, texture, or strength which stops the fracture growth (King, 2012). Fisher & Warpinski (2011) observe height-growth limiting mechanisms controlled by geological structure, with a mix of horizontal and vertical fractures created below a critical depth. King *et al.* (2008) report height limiting of 15 to 30 metres in the Barnett well, even though no obvious immediate rock strata barriers were identified. However, it could be argued that some form of discontinuity was present.

The observation that horizontal fractures can predominate during hydraulic fracturing shows that geology plays a large role in dictating the propagation of fractures. This means that experience can be used to ensure the correct units are hydraulically stimulated if there are any risks associated with upward migration of hydraulic fractures. Selecting facies that are weak within a shale formation will result in lithologically bound fractures that are not able to migrate into stronger bounding units.

7.7 Knowledge gaps and recommendations

This chapter has described the state of understanding of the control that drilling engineers have on the extent of the propagation of hydraulic fractures during stimulation. The following statements on current knowledge, knowledge gaps and recommendations can be made:

- The use of microseismic monitoring has increased the knowledge of the extent of the stimulated reservoir volume. This has allowed model predictions to be calibrated and refined. However, numerical models have been limited in their ability to fully describe hydraulic fracturing in certain settings suggesting the full physics of the system is not encapsulated within the modelling approaches.

- The full complexity of the formed fracture network is not fully understood. A means of determining fracture density and other fracture properties is needed.

- Hydraulic fracture fluid volume plays a role on the full extent of hydraulic fractures. While the processes governing the role of fluid volume are understood, a means of predicting fracture propagation lengths is not yet available.

- The process of leak-off needs to be better understood in order to better predict fracture lengths. This includes the role of pre-existing fractures on leak-off and the role of the permeability of the shale.

- The role of hydraulic fracture fluid pressurization rate is acknowledged. However, a full understanding of this has yet to be achieved.

- Advanced hydraulic fracturing design has been proposed. The full consequence of these strategies has yet to be realized. Complex, controlled fracture networks are theoretically possible; these need to be properly tested in the field to refine drilling engineering.

- Proppants and additives act to alter the viscosity of the hydraulic fluid. The full impact of this on fracture propagation and networks has yet to be achieved.

- Considerable variation in physical properties of shale facies results in lithologically bound fracture networks. This needs to be tested on European shale units.

8 CONCLUSIONS: KNOWLEDGE GAPS

It is clear that there is considerable understanding of the initiation, propagation and arrest of hydraulic fracturing due to the downhole technologies employed during stimulation and exploitation. However, this knowledge is incomplete and a number of unknowns still exist. This is in part due to the depth that hydraulic fracturing occurs and the difficulty of acquiring information on the process at such depths.

One limitation of the understanding comes from the most significant source of information. The literature is dominated by examples of North American shale gas operations. Depending on the source of the estimate, between 50,000 and 100,000 wells have been drilled for shale gas/oil in North America; for instance 8,341[5] wells have been drilled in Pennsylvania alone by the end of 2014. This compares with no active shale gas production wells in Europe and less than 100 exploration boreholes drilled to assess the European shale gas resource. Research is needed as to the differences seen between the major North American shale gas formations (such as the Marcellus, Woodford, Haynesville, Barnett, Mancos, Bakken, New Albany and others) and the potential European shale gas plays (such as Alum (SE, DK), Baltic, Podlasie (PL), Lublia (PL), Dneipe (UA), Ponnonian-Transylvanian (SK, AT, HU, HR, BA, RS), Carpathian-Balkanian (RO), Saxony (DE), France Southeast (FR), Paris (FR), North Sea – German basin (DE), Bowland, Lias, Oxford, Corallian, Kimmeridge, Gullane, West Lothian Oil Shale, Lower Limestone, Limestone Coal (UK), Lusitanian (PT), Cantabrian (ES)). Geologically there are clear differences between the basins that host these shales and it cannot be assumed that hydraulic fracturing will have the same consequences on the different rocks in both continents. The main differences that might occur between all prospective shale gas plays is thickness of high TOC facies, mineralogy of individual facies, relative tensile strength and elastic properties of facies, degree of natural fracturing, and *in situ* stress state.

A gap in the understanding results from the general lack of well-preserved core material from depth that has been obtained by pressure-coring to maintain the stress state of the samples. This also reduces the effects of drying, chemical, and biological degradation and is vital in order to compare datasets from the same shale gas play, or between different shale gas plays. Numerous experimental studies have been conducted on core material that has not been preserved and in some cases has been air-drying for decades. This will influence experimental results and is therefore undesirable. Comparison of experimental studies is also made difficult by the lack of disclosure of experimental protocols used by different workers. Little research has been conducted on quantifying tensile and/or hydraulic fracturing properties in the laboratory or on the effect of perforation on the mechanical properties of shale. It is clear that mineralogy plays a major control on the initiation of fractures in shale. More research is required in order to

[5] Source: Pennsylvania Department of Environmental Protection, quoted at http://geology.com/articles/marcellus-shale.shtml

quantify the influence of different mineral constituents on the overall mechanical properties. A better understanding of where and how fractures are initiated is also required.

Shale is a highly variable and heterogeneous material. Both variability and heterogeneity need to be better understood and incorporated into numerical models. The drilling of a deviated well creates a complex stress field. The complexity of stress can be described for a perfectly elastic medium, the complexity of shale variability and anisotropy need to be incorporated so that a better understanding of where fracture initiation is likely to occur.

Many numerical approaches exist; modelling should work towards a unified approach of describing fracture propagation in shale. Numerical models tend to over-predict the length of hydraulic fractures that are formed. Current understanding of fracture arrest in a complex geological unit, such as shale, needs to improve to numerically represent the hydraulic fracturing process. Experimental observations are needed on fracture propagation in a complex, layered shale in order to identify the controls of fracture deviation and/or arrest. Shale does not behave as a perfect elastic medium and as a result numerical models need to incorporate the full thermo-hydro-mechanical-chemical coupled behaviour of the rock. Many studies have been conducted that consider shale as a uniform, homogenous, elastic material. Whilst complexity is difficult to incorporate within numerical models, representative physics is required with good ground truth field data.

Natural fractures and microfractures may represent planes of weakness within natural shale formations. It is likely that the density and orientation of these features will influence fracture propagation. Thus, the interaction between natural fractures and hydraulic fractures is a key area of research. Natural fracturing will be controlled by current and historical tectonic stresses and mineralogy. Mineral infill of geological fractures also has a control on whether natural fractures influence hydraulic fractures or not. Therefore an increase in knowledge of natural fracture properties, the stress regime, the role of mineralogy, and the interaction of natural and induced hydrofractures is required to better understand the stimulated reservoir volume. Vertical fractures of varying density predominate in shale formations. Bedding-parallel fractures may also be present, but are not ubiquitous. The scale of the fracturing is variable, as is the mineralogy of cement infill. In certain cases this mineral infill can strengthen the host rock, whereas in others it is a mechanical weakness. The presence of microfractures in shale formations and their influence on hydraulic fracture propagation is poorly understood and represents a gap in understanding. It is vital that similar observations are made for shale-gas prone formation in Europe to describe the expected natural fracture population.

Microseismic monitoring has increased knowledge of the extent of the stimulated reservoir volume. However, the full complexity of the formed fracture network is not fully understood; for instance, a means of determining fracture density is required. Microseismic monitoring has allowed model predictions to be calibrated and refined, although numerical models have been limited in their ability to fully describe hydraulic fracturing in certain settings suggesting the full physics of the system is not encapsulated within the modelling approaches.

Drilling engineering plays an important role in controlling hydraulic fracturing. The fracture fluid volume plays a role on the full extent of hydraulic fractures. While the processes governing the role of fluid volume are understood, a means of predicting fracture propagation lengths is not yet available. The process of leak-off also needs to be better understood in order to predict fracture lengths. The role of hydraulic fracture fluid pressurization rate is acknowledged as contributing to fracture lengths, yet a full understanding of this has not yet been achieved. Advanced drilling techniques have been proposed, with the full consequence of these strategies yet to be realized. Complex, controlled fracture networks are theoretically possible; these need to be properly tested in the field to refine drilling engineering. The full impact of proppants and additives on hydraulic fluid viscosity and subsequent fracture propagation is also required.

Fisher & Warpinski (2011) highlight the state of knowledge of the shale gas system. They state that an understanding of the geology surrounding the target area is needed in order to estimate the direction of fracture propagation. Their concluding remarks clearly assess the current state of understanding:

> *"The directly measured height growth is often less than that predicted by conventional hydraulic-fracture propagation models because of a number of containment mechanisms….Some of those mechanisms include complex geologic layering, changing material properties, the presence of higher permeability layers, the presence of natural fractures, formation of hydraulic-fracture networks, and the effects of high fluid leak-off."*

> *"Fracture physics, formation mechanical properties, the layered depositional environment, and other factors all conspire to limit hydraulic-fracture-height growth, causing the fracture to remain in the nearby vicinity of the targeted reservoirs."*

Thus the current state of knowledge is yet to fully predict the extent of hydraulic fracturing during shale gas operations and the comparisons and contrasts seen between European and North American shale facies has yet to be fully defined.

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