Wendy Strangeway

From: Mark Hill
Sent: 18 February 2015 13:43
To: Planning
Subject: FW: EMS-Knapton
Attachments: EMS Seismicity Report.pdf

Pls book in

From: Lucy Wood
Sent: 16 February 2015 17:27
To: Mark Hill
Cc: Katharine Creswell Nigel D'Arcy John Dewar Elizabeth Davies; Paul Foster
Subject: EMS-Knapton

Mark,

Please find attached Rockflow Report relating to EMS-Knapton.

Kind Regards

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August 2014

POTENTIAL FOR INDUCED SEISMICITY DUE TO INJECTION OF PRODUCED WATER AT EM-S

NON-TECHNICAL SUMMARY

INTRODUCTION

Third Energy is planning to develop the Ebberston South gas discovery in the Cleveland Basin, North Yorkshire. Highly saline Produced Water will be obtained in conjunction with the gas from the Kirkham Abbey Formation, and the development scheme proposes injection of that water for disposal into the Sherwood sandstone formation in the Ebberston South (EM-S) well.

Third Energy (and its predecessors) has been injecting Produced Water back into the KAF within the Vale of Pickering for many years with no adverse effects. The Vale of Pickering and the Cleveland Basin is an area of generally low seismicity, as recorded by the British Geological Survey (see below).

While this is not a hydraulic fracturing project, onshore injection schemes have been subject to increased scrutiny since Cuadrilla's hydraulic fracturing activity in the Preese Hall-1 well initiated seismic events that were felt by the local population. In addition, links between Produced Water injection and induced seismic events in the United States of America have increased concerns about Produced Water injection activities in the United Kingdom.

BACKGROUND

A seismic event is caused by the sudden release of energy in the Earth's crust which creates seismic waves at the surface. In order for the energy to be released movement of the earth must occur. The earth's crust is in continual movement as Tectonic Plates move across its surface. However, the plates move in jerks rather than smoothly. As the plate tries to move stress is built up and the stresses are reduced by the release of energy via intermittent fault movements, resulting in an earthquake. As most of the movement occurs along plate boundaries, this is where the largest and most common earthquakes occur.

The Cleveland Basin lies within the Eurasian plate, some 2000 kilometres from the closest plate boundary. Within a tectonic plate, there is little or no relative motion and stress levels generally remain constant. As a consequence, there are relatively few seismic events. This doesn't mean that there are none, only that they are small and infrequent. The stresses that give rise to events in these situations may be as a result of post glaciation re-adjustment (isostatic readjustment), due to the melting of considerable ice thickness after the last ice age; and the regional stress in the earth's crust created by movement elsewhere; or mining; amongst other occasional small natural ground movements.

There are different ways of measuring the size or magnitude of seismic events, but one of the first methods for describing the magnitude and probably the most commonly known, was developed by Charles Richter in 1932 and is known as the Richter Scale. An important aspect of the Richter Scale is that it is logarithmic, which means that the amplitude of a magnitude 6 event is ten times greater than a magnitude 5; 5 is ten times greater than 4; and so on. Figure 1 shows the locations of events recorded in the North Yorkshire area between 1970 and 2014. It can be seen that only three have been recorded in the vicinity of EM-S; all with a magnitude of less than or equal to 2. The two with recorded depths originated at >5km.

Within the context of recent historic observations, during which Produced Water has been injected into the Kirkham Abbey Formation, Ebberston South is located in an area of very low seismic activity with recorded activity limited to three events that would be barely perceptible by people. Within this context, Third Energy have commissioned a detailed technical report titled "Ebberston South Water Injection : Seismic Event Risk Assessment" dated July 2014, by specialist consultants Rockflow Resources. The study was initiated to "investigate and, where possible, to quantify the risk that the proposed injection scheme would trigger seismic activity". The principal aspects of the technical report are summarised below.

ROCKFLOW RESOURCES REPORT

At any point in the subsurface the rocks are subjected to forces or stresses due to the weight of the overlying rock and tension in the earth's crust. In addition, the water pressure in the formations provides a negative force, similar to buoyancy. The difference between the earth stresses and water pressure is known as the "Effective Stress".

Water injection into a reservoir will increase fluid pressure (unless water is removed at the same time). As that fluid pressure rises, the local effective stress is reduced, such that in theory the rocks can crack or move, potentially leading to fracturing or fault movement and hence generating a seismic event.

The events at Preese Hall caused a number of events, the largest of which had a magnitude of 2.3 on the Richter scale, which (as discussed above) is a very low magnitude event. Water was injected at high pressure into Preese Hall-1 in a process that was deliberately designed to cause hydrofracturing of the impermeable shale rock. However, the water unintentionally entered a nearby pre-existing naturally occurring fault. As the fluids were unable to dissipate into the shale, pressure along the fault plane rose until the effective stress was reduced to zero and fault movement occurred, and hence a small seismic event.

The magnitude of an event is dependent on the area of the fault that moves. At Preese Hall, the low permeability of the shale on either side of the fault plane did not allow the fluids to dissipate into a large volume, but continued to spread along the fault plane, so that an area of about $10,000m^2$ is thought to have been affected.

In order to provide operating guidelines for future water injection schemes, DECC have issued criteria that accept resultant seismic activity up to a magnitude of 0.0 on the Richter scale, and require all injection to cease if any monitored seismic event breaches a magnitude of 0.5. Such magnitudes are only detectible by sensitive instruments.

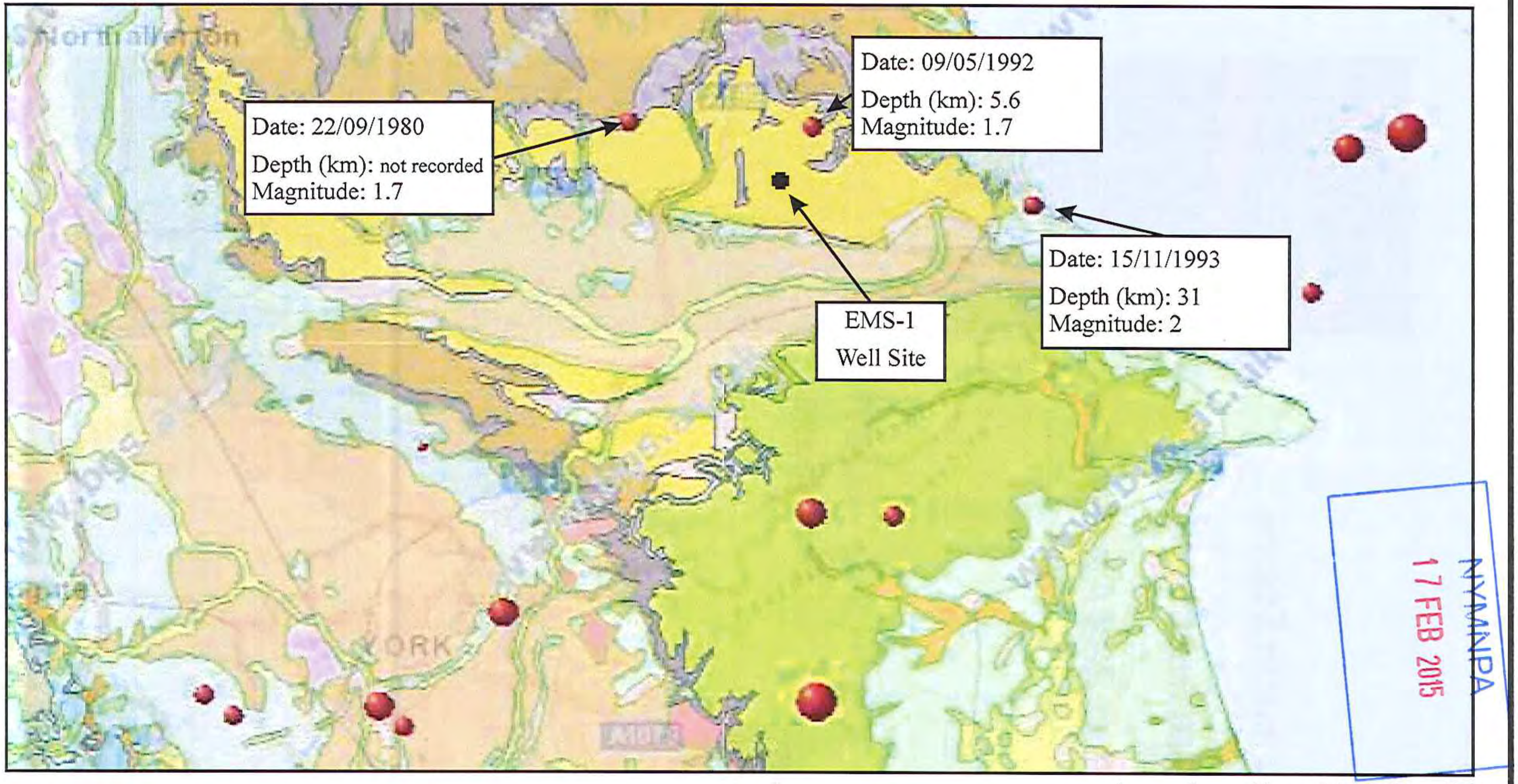
The Ebberston South dewatering scheme will produce up to $556m^3$/day (3,500 bpd) of Produced Water which Third Energy propose to dispose of by injection into the Sherwood Sandstone Formation. Unlike the shale at Preese Hall, the Sherwood Sandstone Formation is very well understood and there is a great deal of data on its porosity and permeability from gas and oil wells drilled in the North Sea, on shore in the UK and other oil and gas basins. This data shows that the Sherwood Sandstone Formation has sufficient porosity and permeability to accept injected water, and that the proposed injection rates and pressure will not induce fracturing of the rock.

The Ebberston South area is not structurally complex, and there is no evidence that the EMS-1 well encountered any faults. However, interpretation of seismic survey data shows that there are faults in the area. Standard analysis techniques allow the strength of a rock mass and the effective stress acting on that rock mass to be evaluated. Using the known permeability, porosity, rock strength and stress data from oil and gas exploration and production wells in the Sherwood Sandstone Formation in the UK, the risk of fault movement can be assessed.

Following detailed analysis the Rockflow Resources report concludes that the likelihood that the injection scheme will cause a seismic event with a magnitude greater than 0.0 is assessed as less than 1 in 100,000 and water injection at the proposed rates and pressures can proceed within DECC's "Green" category. This level of risk is much less than that of being killed by lightning.

Despite the very low risk of a seismic event, it is recognised that continued water injection may very gradually increase formation fluid pressures. The rate of increase will depend on the final injection rate and the hydraulic properties of the sandstone around the injection well. Therefore, a monitoring program is recommended to track formation pressures. Injection rates can be controlled to maintain pressures below a safe threshold and the data can be used to guide future injection strategy decisions and regulatory control.

In overall conclusion, due to the planned low injection pressures and injection rates, it is extremely unlikely that water injection could cause sufficient localised pressure increases to initiate fracturing of the rock or movement on existing fault planes. It is therefore extremely unlikely that the proposed water injection scheme will cause any detectable seismic events. The extremely low residual risks associated with gradual increase in formation pressure can be fully mitigated by monitoring and control systems and in the unlikely event that threshold values are approached, stopping injection will prevent a seismic event from occurring.



Ref: http://mapapps.bgs.ac.uk/geologyofbritain/home.html

0 5 10 15 20 25km
approximate scale

envireau WATER

Ref: P:\Third Energy EMS (1700)\Technical Report\Figure 1 Date: 27/08/14	**Third Energy**
Figure 1	Seismic Events 1970 - 2014

Ebberston South

Water Injection:

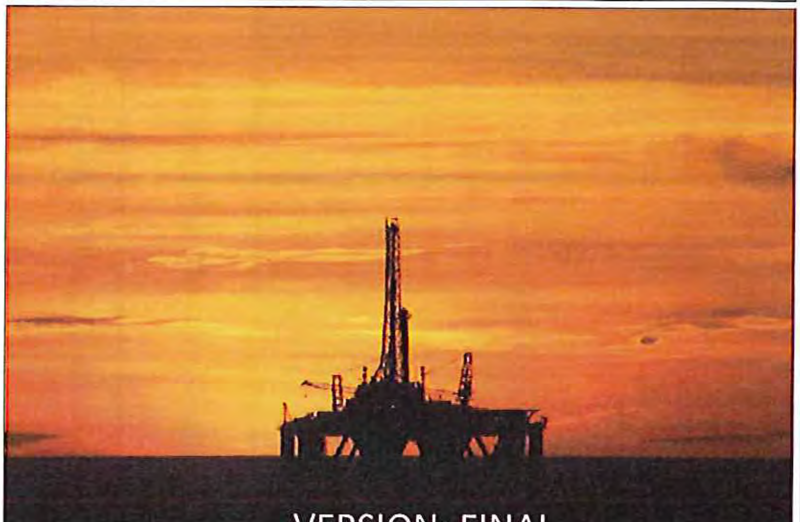
Seismic Event Risk Assessment

rockflow RESOURCES

CLIENT:

Third Energy

Report Date
23rd July, 2014



VERSION: FINAL

CONSULTANTS TO THE PETROLEUM INDUSTRY

rockflow
RESOURCES

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. Rockflow Resources Ltd. shall have no liability arising out of or related to the use of the report.

Status	FINAL
Date	23rd July 2014
Issued by	Graham Cocksworth
Reviewed by	Andy Spriggs Managing Director Rockflow Resources
Approved by	Graham Cocksworth Project Manager Rockflow Resources

CONSULTANTS TO THE
PETROLEUM INDUSTRY

Executive Summary

Third Energy is planning to develop the Ebberston South gas discovery in the Cleveland Basin, North Yorkshire. Highly saline water will be produced in conjunction with the gas from the Kirkham Abbey Formation, and the development scheme proposes injection of that water for disposal into the Sherwood sandstone formation in the Ebberston South-1 (EMS-1) well.

Onshore injection schemes have been subject to increased scrutiny since Cuadrilla's hydraulic fracturing activity in the Preese Hall-1 well initiated seismic events that were felt by the local population. In preparation for the field development application, Third Energy is conducting a number of environmental risk assessment studies, including an assessment of the risk that their plans might generate an event similar to the Preese Hall earthquake.

Water injection into a reservoir raises the formation fluid pressure; if that fluid pressure reaches the local fracture gradient, then the rocks can fail, potentially leading to fracturing or fault movement and hence generating a seismic event.

In order to provide operating guidelines for water injection schemes, DECC have issued criteria that accept resultant seismic activity up to a magnitude of 0.0 on the Richter scale, and require all injection to cease if any monitored seismic event breaches a magnitude of 0.5.

The proposed water injection scheme for EMS-1 is designed to dispose of produced water into the Sherwood sandstone, which has sufficient porosity and permeability to accept large volumes of injected water. The current study has assessed the injectivity of the Sherwood formation in EMS-1:

- An electric submersible pump (ESP) will be used to inject water via the annulus into the Sherwood formation, and the planned pump configuration will not generate pressures that are high enough to cause fractures or faults to reactivate.
- Frictional losses in the annulus due to the slim well design will limit the achievable injection rate to 3000-3500 bpd unless a surface booster pump is installed.
- If average reservoir permeability is greater than 5mD, the well will be capable of injecting the maximum planned rate of 3500 bpd without exceeding the fracture gradient.
- The pressure required to pump 3500 bpd could exceed the local fracture gradient if the average reservoir permeability is below 5mD.
- Injection at a rate of 3500 bpd into reservoir with an average permeability of less than 2-3mD would lead to formation pressures above the fracture gradient over an area in excess of $5m^2$ around the wellbore, the level at which a seismic event of magnitude 0.0 may be generated.
- Available data indicate the average reservoir permeability is at least 10mD and is probably in the range 25-80mD. If the average reservoir permeability is above 5mD as expected, water can be injected at pressures well below the fracture gradient for the full range of anticipated injection rates.

In conclusion, due to the relatively low planned injection pressures and injection rates, it is considered extremely unlikely that water injection could cause sufficient localised pressure increases to initiate hydraulic fracturing of the rock or movement on existing fault planes. It is therefore extremely unlikely that the proposed water injection scheme will cause any seismic events. Further, the planned ESP configuration will not be able to deliver a BHP high enough to exceed the fracture gradient, and hence the only consequence of lower reservoir permeability will be lower injection rates.

So, in order to minimise the risk of raising the BHP above the fracture pressure, it is recommended that the ESP should not be supplemented by a booster pump. In such a configuration, water injection at the proposed rates and pressures can proceed within DECC's "Green" category, and the likelihood that the injection scheme will cause a seismic event with a magnitude greater than 0.0 is assessed as less than 1 in 100,000.

Continued water injection will gradually increase formation fluid pressures. Therefore, a monitoring program is recommended to track formation pressures over the initial test period, providing data that can guide future injection strategy decisions.

Contents

Figures

Tables

1. Introduction

Third Energy is planning to develop the Ebberston South gas discovery in the Vale of Pickering, North Yorkshire (Figure 1-1). Up to 3,500 barrels per day (bpd) of highly saline water will be produced in conjunction with the gas, and the development scheme proposes injection of that water for disposal into the Sherwood Formation in the Ebberston South-1 well (EMS-1).

Onshore injection schemes have been subject to increased scrutiny since Cuadrilla Resources Ltd. initiated a small seismic event during hydraulic fracturing activity in their shale gas Preese Hall-1 well (De Pater and Baisch, 2011). Water was injected into the well at high pressure with the intention of hydraulically fracturing the low permeability shale. Instead, the water entered a fault and increased the fluid pressure, triggering movement that was registered as an earthquake.

The Ebberston South area is not structurally complex, and there is no evidence that the EMS-1 well encountered any faults. However, seismic interpretation shows that there are faults in the area around Ebberston South. Consequently, Third Energy wishes to understand the risk that water injection into the Sherwood Formation may cause fault reactivation in a manner similar to the Preese Hall-1 event (i.e. direct injection into a fault plane), or via a mechanism linked to fluid pressure increase within a fault compartment.

The current study was initiated to investigate and, where possible, to quantify the risk that the proposed injection scheme would trigger seismic activity.

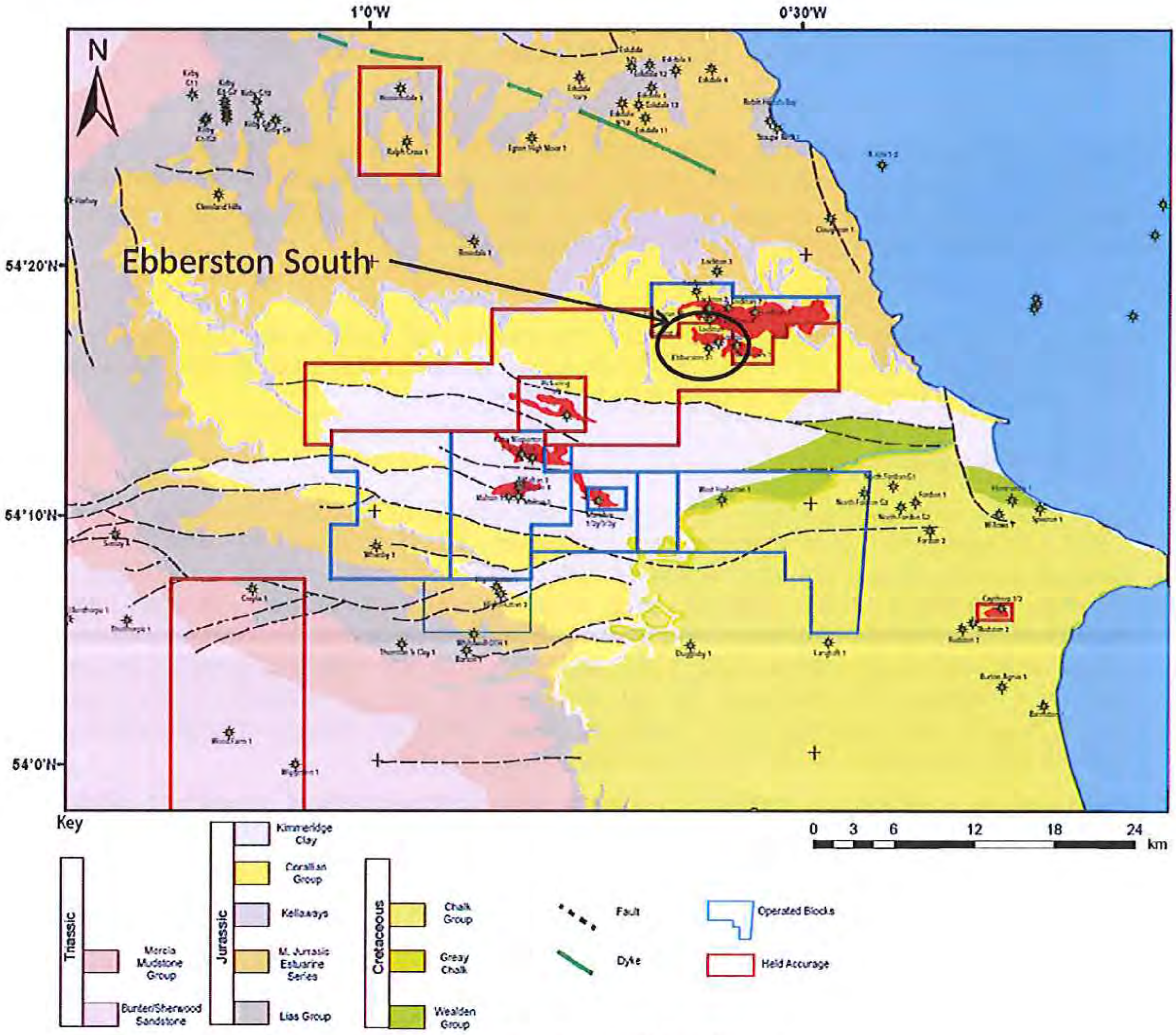


Figure 1-1 Ebberston South location map

2. Background Discussion

In order to frame the assessment of the risk associated with water injection into EMS-1, a discussion of the underlying principles of subsurface stress and rock failure is useful.

2.1. Subsurface Stress

At any point in the subsurface a rock can be considered to be subject to three orthogonal principle stresses (σ_1, σ_2, σ_3, where by definition $\sigma_1 \geq \sigma_2 \geq \sigma_3$) and additionally an opposing isotropic pressure arising from the fluid present in the pores. These stresses arise from the gravitational load from the overlying sediments (σ_v) and the confining/compressive force exerted by the surrounding rocks (σ_h), which is resolved into perpendicular maximum ($\sigma_{h\,max}$) and minimum components ($\sigma_{h\,min}$).

The fluid pressure (P_f) provides an isotropic stress which opposes the principle stresses i.e. partially offsets the vertical force due to the overlying sediment column. Assuming that the fluid pressure acts on the complete surface normal to the applied vertical stress, then the net stress (σ_{veff}) acting on the plane is the vertical stress minus the pore fluid pressure:

$$\sigma_{veff} = \sigma_v - P_f$$

This relationship is also known as Terzaghi's Law, and effective stresses analogous to that given above can be defined for all the principle stresses (Terzaghi, 1923, 1936; Terzaghi & Peck, 1948).

In regions where an excess fluid pressure (P_{ex}) has been generated, either through naturally occurring overpressures or via fluid injection, then Terzaghi's law may be rewritten as:

$$\sigma_{veff} = \sigma_v - P_f - P_{ex}$$

The above formulation shows that the generation of excess fluid pressures will result in a lowering of the effective stresses acting at a point. As the fluid pressure acts to oppose the principle stresses, then should the fluid pressure exceed the minimum (generally horizontal, $\sigma_{h\,min}$) stress, failure by hydrofracturing is possible. In principle this will occur where:

$$P_f > \sigma_3 + \mathrm{T}$$

where T is the tensile strength of the rock. The presence of faults in the subsurface, particularly associated with the structures of interest to the oil and gas industry means that for practical purposes the tensile strength of the rock can frequently be ignored.

2.2. Rock Failure

The conditions under which a rock will fail can conveniently be represented in the Mohr stress diagram. This is a 2D representation of 3D stress space in which one axis is defined as the effective normal stress (here denoted by σ) and the other as the effective shear stress (denoted by τ; see Figure 2-1). The equations describe a circular locus of paired values (σ, τ), of the normal and shear stresses, that operate on planes of all possible orientations within a given body that has been subjected to known values of σ_1 and σ_3. The stress field is defined by a circle on which the diameter is equal to the difference between the maximum ($\sigma_{1\,eff}$) and minimum ($\sigma_{3\,eff}$) effective stresses, centred on ($\sigma_{1\,eff} + \sigma_{3\,eff}$)/2. The threshold stress conditions under which rock fails are represented in the Mohr diagram by a curve known as the "failure envelope" (Figure 2-1).

Rocks fail by a variety of mechanisms ranging from hydraulic failure through to dilatant shear (faulting). Failure occurs in Mohr space when the failure envelope is tangential to the circle representing the in situ effective stresses. The mode of failure can be read off from the point on the failure envelope at which this occurs.

The effect of increasing fluid pressure is to reduce all normal effective stresses (σ_1, σ_2, σ_3) by approximately equal amounts (assuming a scalar poro-elastic coefficient). As a consequence, the Mohr circle of a rock affected by high pore fluid pressures will be shifted towards the origin of the diagram and, therefore, closer to the failure envelope (Figure 2-2). At sufficiently high pore fluid pressure the Mohr circles will become tangential to the failure envelope and failure will occur. When the fluid pressure exceeds the minimum (generally horizontal, $\sigma_{h\,min}$) stress, failure will be by hydrofracturing.

2.3. Minimum Horizontal Stress (MHS) or Failure Envelope

The difference between the minimum stress and the fluid pressure is known as the "trap integrity" or minimum effective stress (MES). Traps where this effective stress is very low cannot contain significant pressure differentials and therefore cannot retain large hydrocarbon columns. The difference is also important in drilling operations as it provides the drilling margin necessary to contain kicks.

From the preceding discussion it follows that if we can represent the relationship between the maximum and minimum stresses, and the failure envelope as a function of depth, then we have a method for establishing the conditions under which rocks will fail as a function of increasing fluid pressure (Figure 2-3).

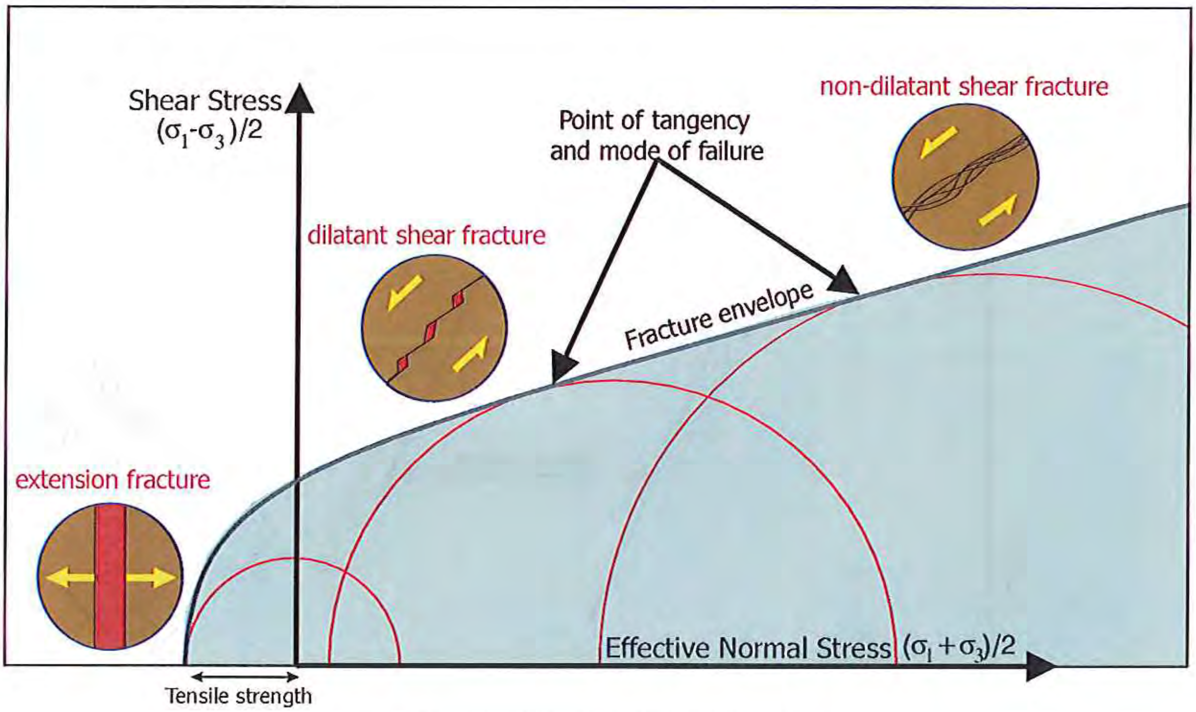


Figure 2-1 Mohr seal failure criteria

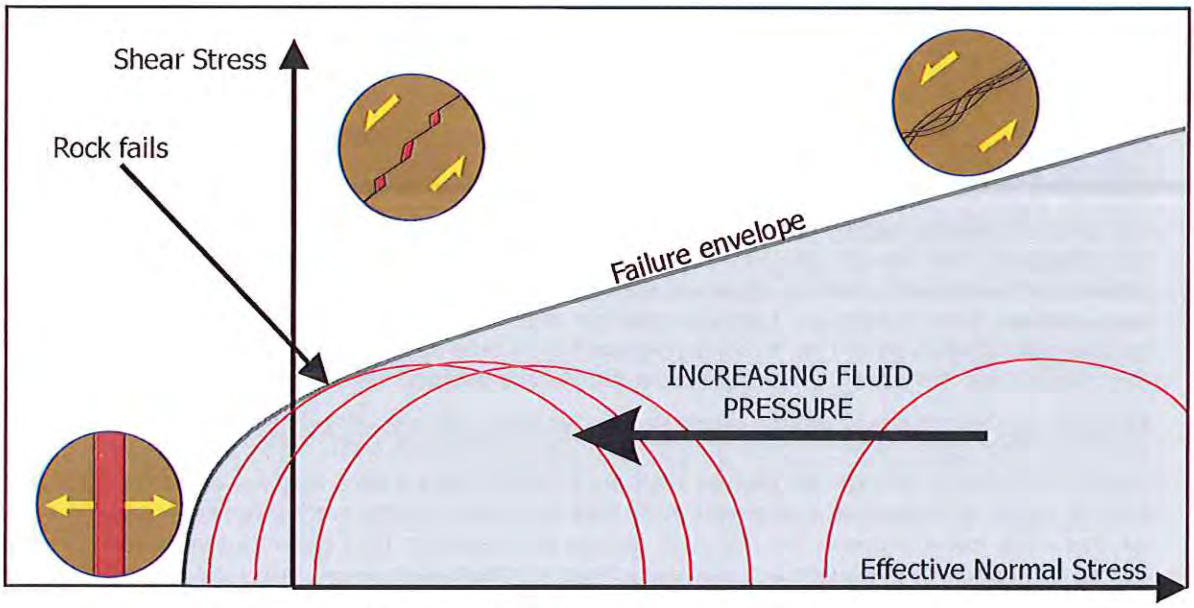


Figure 2-2 Effect of increasing fluid pressure

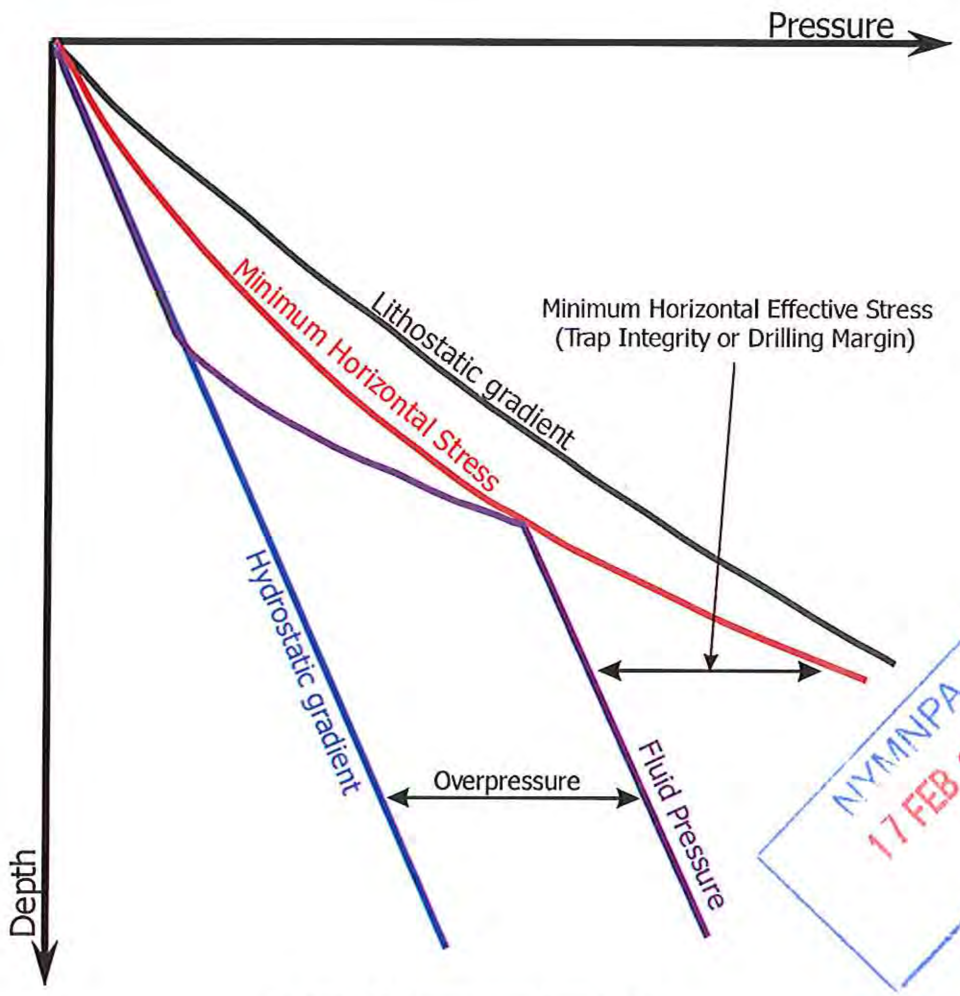


Figure 2-3 Overpressure terminology

There are a number of sources of data that provide estimates of either the minimum in situ stress or the failure envelope of the seal. The best data are provided by micro-frac tests which not only give a good estimate of the minimum horizontal stress (the Fracture Closure Pressure, FCP) but also the tensile strength of the rock (Formation Breakdown Pressure). Unfortunately, micro-frac tests are extremely rare.

More commonly performed are the leak-off tests, which are usually carried out at casing shoe to estimate formation strength and provide the most readily available data to assess formation strength. Leak-off pressure (LOP) measurements can be shown to be greater than the minimum horizontal stress. LOP tests are carried out by pumping fluid down hole and plotting pressure as a function of volume of fluid pumped. The leak-off pressure has been achieved when a deviation from a linear relationship between pressure and volume pumped can be clearly recognised. Unfortunately, LOP data are prone to measurement error (errors are typically $\pm$200 psi and may reach $\pm$400 psi) and have to be carefully quality-controlled to be of use. In particular one has to take care a true LOP test has been carried out (i.e. that a clear deviation between pressure and volume pumped has been observed).

Because of the unknown tensile strength of the rock and the inherent measurement errors, an individual LOP measurement cannot be used as a reliable measure of the failure envelope. However, if quality-controlled LOP data are plotted together with RFT data from a regional dataset then a pattern such as shown in Figure 2-4 is observed. Note that the there is little overlap between the RFT and LOP data as if the lower bound of the LOP data defines the maximum fluid pressure that the rock can hold. Indeed in highly overpressured terrains leaky traps correspond to those with fluid pressures which lie on this lower bound of the LOP data. Failure by hydraulic fracturing would be expected to occur when the fluid pressure exceeds the sum of the minimum stress and the tensile strength of the rock.

As discussed earlier failure can also occur if the fluid pressure increases, moving the Mohr circle toward the tensile regime until it intersects the failure envelope. Hence, the lower bound of the LOP trend shown in Figure 2-4 represents the failure envelope of the seal, and approximates to the minimum horizontal stress of the rock, the distinction between the two being below the resolution of the data.

In recent years, there has been an increased use of formation integrity tests (FITs) rather than leak-off tests. While completely understandable from a wellbore integrity standpoint, FITs do not provide the same quality of information regarding the local stress regime. Typically, FITs establish that the rock will hold the maximum mudweight that is anticipated for the subsequent hole section; they do not break the rock, and generally the tested pressure is less than the minimum stress component. Consequently, care must be taken to differentiate between formation integrity tests (and other forms of limit-test) and true leak-off pressure tests.

2.4. Earthquakes

An earthquake is the result of a sudden release of energy in the Earth's crust that creates seismic waves. The stress systems acting on rocks should cause constant motion or strain. However, the low theoretical strain rates are generally resisted by friction, and the rocks deform elastically, storing potential energy. The release of that energy in a single event or movement of the earth is registered as an earthquake.

The movement of tectonic plates means that the edges of those plates are subject to constant strain, and hence to ever increasing stresses. Those stresses are reduced by fault movements, but the persistent relative motion renews the stress field, and hence earthquakes repeatedly occur along the same fault systems. Within a tectonic plate, there is no relative motion and stress levels generally remain constant. Consequently, there are relatively few earthquakes away from active plate margins.

In its most general sense, the word earthquake is used to describe any seismic event – whether natural or caused by humans – that generates seismic waves. Earthquakes are caused mostly by rupture of geological faults, but also by other events such as volcanic activity, landslides, mine blasts, and nuclear tests. However, taken to the extreme limits, any release of energy into the ground (for example driving piles, drilling a well, or acquiring seismic surveys), creates seismic waves and can be classified as an earthquake.

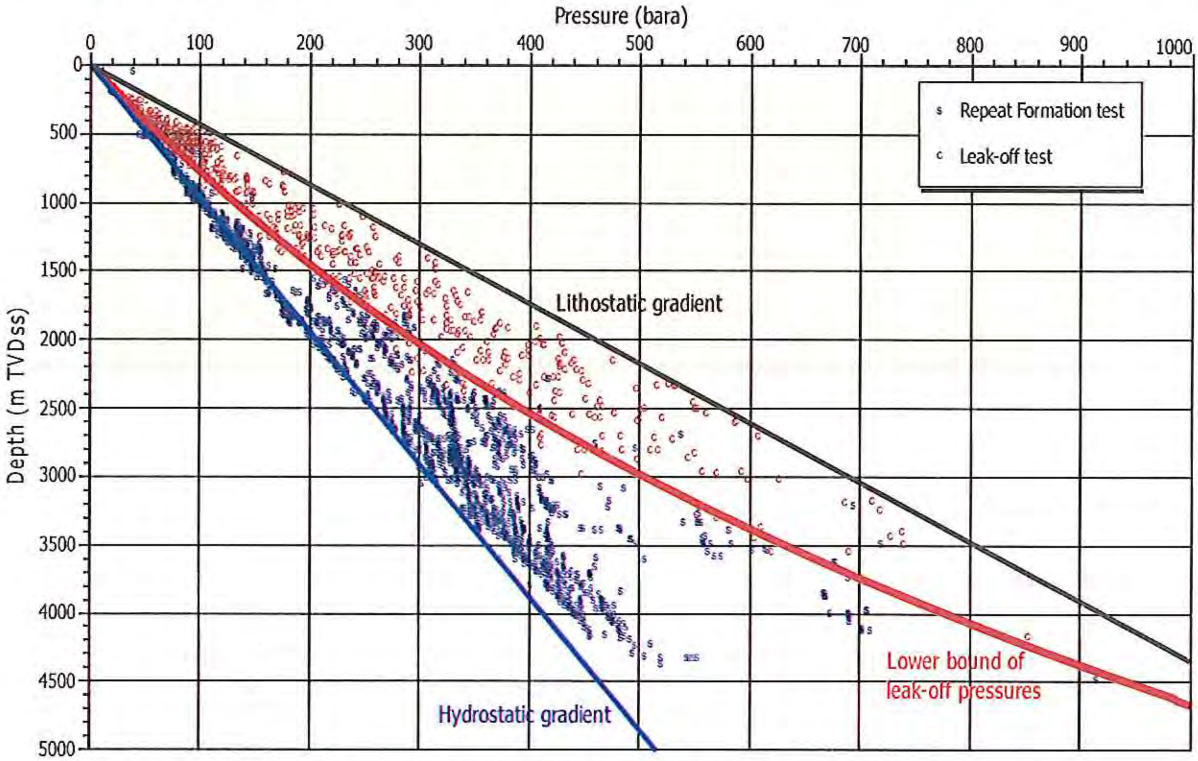


Figure 2-4 An example from the North Sea of regional fluid pressure and LOT data vs. depth

The moment magnitude scale (M_W) is used to measure the size of earthquakes in terms of the energy released. The magnitude is based on the seismic moment of the earthquake (M_O), which is equal to the rigidity of the Earth (G) multiplied by the average amount of slip on the fault (d) and the size of the area (A) that slipped:

$$M_O = GAd$$

and

$$M_W = \frac{2}{3}\log_{10} M_O - 6$$

The moment magnitude scale (MMS) succeeded the older Richter scale, and was defined in such a way as to be broadly comparable; the main difference is for earthquakes of magnitude 5.0 and above. The MMS is now used to measure the magnitudes for all earthquakes, but the terms "Moment Magnitude Scale" and "Richter Scale" are frequently used interchangeably, and the older term remains in most common usage even when referring to measurements made using the MMS (for example, Figure 2-5). Consequently, for consistency all references to earthquake magnitude in the current study are to the "Richter Scale".

Simple mechanical considerations reveal that the shear slip d cannot become arbitrarily large, but is limited by the capacity of the surrounding rock to absorb deformation, and by the amount of shear stress driving the failure process. Therefore, the dominating parameter controlling the magnitude of seismic events is the area over which movement occurs.

The logarithmic scale means that an increase of 1 on the scale is the equivalent to a 32-fold increase in released energy. Earthquakes with a magnitude less than 2.0 are classified as micro-earthquakes (Figure 2-5), and are generally not felt at the surface. Hydraulic fracturing routinely produces microseismic events with a typical magnitude of minus 2 (-2.0), which is too small to be detected except by sensitive instruments. However, occasional larger events can be triggered, and the activity by Cuadrilla at Preese Hall (see section 3.1) has raised public awareness and concern.

Consequently, the UK Department of Energy and Climate Change (DECC) has recently introduced new controls and checks for operators using hydraulic fracturing (DECC, 2014). The document includes the requirement for operators to adopt a 'traffic light' system that controls whether injection can proceed or not, based on seismic activity (Table 2-1).

Traffic Light	Monitored seismic activity level	Action
Green	Less than magnitude 0 on the Richter scale	Injection can proceed as planned
Amber	Magnitude 0 to 0.5 on the Richter scale	Injection can proceed with caution, possibly at reduced rates. Monitoring is to be intensified.
Red	Magnitude 0.5 or higher on the Richter scale	Injection is to be suspended immediately

Table 2-1 DECC's 'traffic light' monitoring system for water injection activity

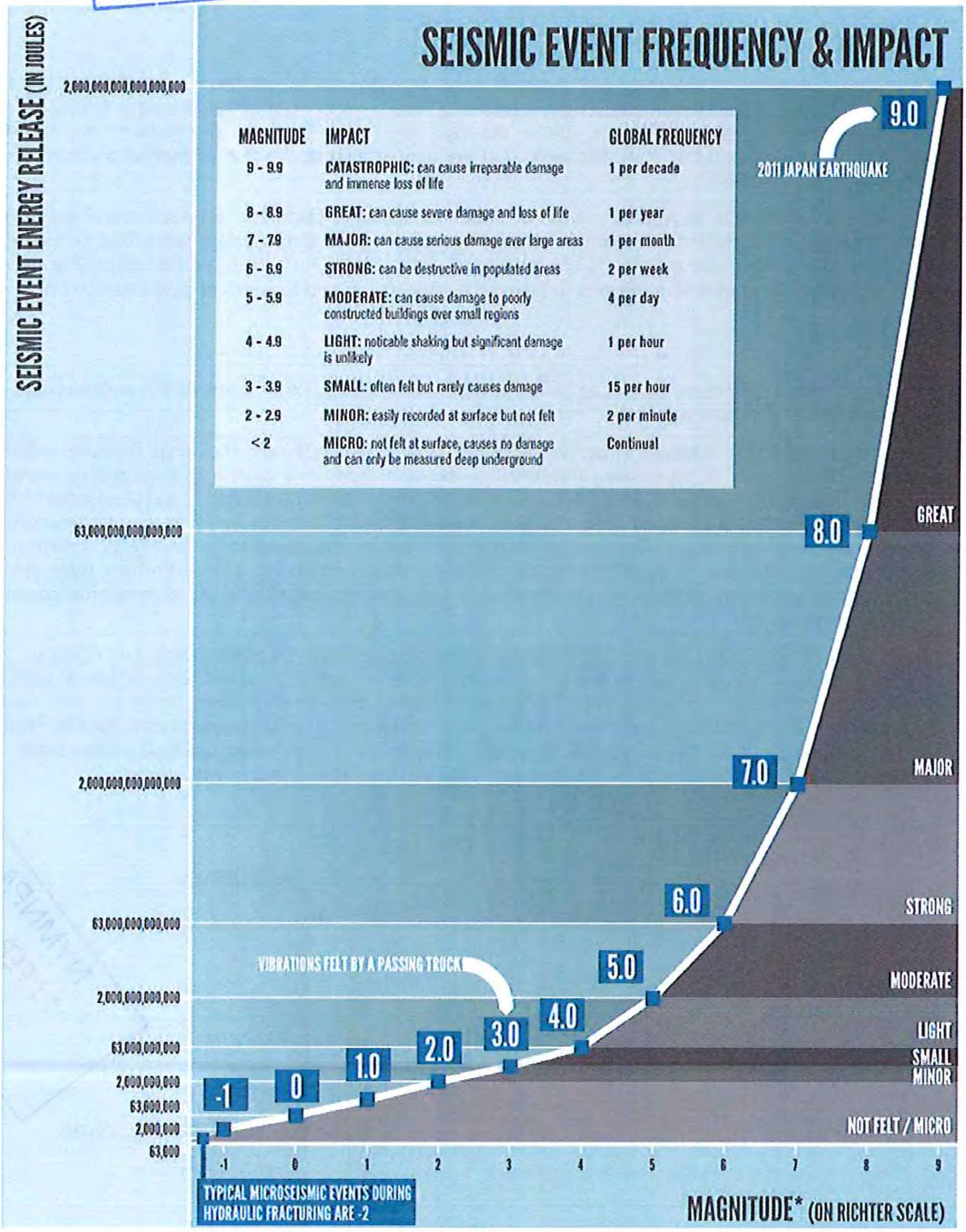


Figure 2-5 Seismic Event Frequency and Impact (source: USGS)

3. Water Injection Effects

Water injection into a reservoir will increase fluid pressure (in the absence of compensating fluid extraction), and hence the effects on the subsurface stress system can be addressed in the context of the preceding discussion. However, there are two separate elements to consider: the transient pressure regime around the injection well, and permanent changes to the formation pressure of the reservoir unit in general.

The injection well acts as a point source of pressure, with the bore-hole pressure raised sufficiently above the ambient reservoir pressure to achieve the required volume injection rates. In a conventional reservoir, the fluids move away from the bore-hole and the local fluid pressure dissipates (Figure 3-1), with a pressure drop (ΔP) at a distance (r) from the well falling as a function of permeability (k):

$$\Delta P \propto \frac{q\mu \ln(r/r_w)}{kh}$$

where q is the steady state flow rate, μ is the fluid viscosity, r_w is the radius of the wellbore and h is the thickness of the reservoir.

Many water injection schemes raise the wellbore fluid pressure above the local fracture pressure, whether intentionally or otherwise. The result is the generation and growth of local fractures, which aid fluid and pressure dissipation by exposing a larger area of rock-face directly to the injected fluids. As the pressures dissipate away from the well, fluid pressure decreases below the fracture pressure, and fracture growth ceases. Since this phenomenon is a common situation for injection schemes, the impact has been subject to significant study, and the nature and extent of the resulting fractures can be modelled prior to injection with commercially available specialist fracture propagation computer simulation packages.

Away from the wellbore, the average pressure of the reservoir will increase as water is injected, with the magnitude of the pressure rise being a function of the compartment size, the injected volumes and fluid compressibility. Obviously, small volumes injected into a very large reservoir will have a negligible effect, but if large volumes of water are injected into a small compartment, then the overall reservoir pressure could rise to the fracture point. This would lead to rock failure on a large scale, and has the potential to trigger a seismic event, i.e. fault movement and an earthquake.

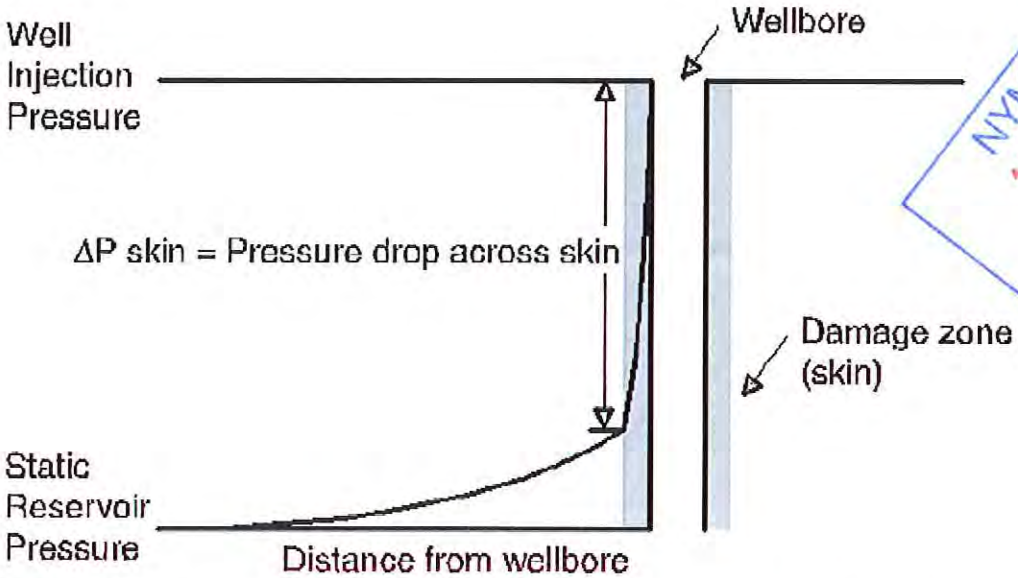


Figure 3-1 The pressure distribution around the wellbore of an injection well

Seismic activity induced by hydraulic reservoir treatments is generally associated with the immediate wellbore vicinity. Such activity typically exhibits small magnitudes and can only be measured by instruments deployed locally, or even in other wellbores within the reservoir. Observations from these instruments indicate that induced seismicity is caused by shear slippage rather than by hydraulic opening of a fracture (hydrofracture), as evidenced by the seismic radiation pattern. Due to the small fracture opening velocity, hydrofractures produce no measurable seismic signals (Keppler et al., 1988). Consequently, the seismic signals associated with hydraulic fractures are interpreted as shear-slip events occurring along existing failure planes such as faults, natural fractures, bedding planes and other discontinuities in the rock (Warpinski et al., 2006).

Fluid injection induced seismicity is commonly described by the Hubbert-Rubey mechanism (Hubbert & Rubey, 1959; Healy et al., 1970; Hsieh and Bredehoeft, 1981), where hydraulic overpressures reduce the effective normal stress acting on existing fractures (or similar zones of weakness) until the ratio between shear and effective normal stress exceeds the coefficient of friction and shear slippage occurs, i.e. when:

$$\frac{\tau}{\sigma_n - P_{fl}} > \mu$$

where τ and σ_n denote the shear and normal stresses resolved on a fracture plane, P_{fl} the in situ fluid pressure, and μ the coefficient of friction.

From this equation, it follows that induced seismicity only occurs when several conditions are met:

1. Shear-stresses need to be resolved on the shearing plane, implying an anisotropic stress field.
2. Shear plane orientation relative to σ_1 and σ_3 will control the magnitude of τ, and hence the likelihood of failure.
3. The shearing plane needs to be mechanically strong enough to support high shear-stresses, implying a significant strength of the associated rocks (rigidity). Furthermore, seismic energy is only released if the rigidity of the rocks is sufficiently large to allow for an almost instantaneous failure.
4. If fluid overpressures are the driving force for the induced seismicity, then the shearing plane must exhibit some natural hydraulic permeability.

This mechanism is valid at both the well-bore and reservoir scale.

3.1. The Preese Hall Earthquake

Preese Hall-1 was spudded on August 16th 2010. The well is located adjacent to Preese Hall farm on the Fylde coast of NW Lancashire and is believed to be the first dedicated shale gas well drilled in the UK. The well encountered the top of the Bowland Shale, the target formation, at a depth of 6540ft MD (6492ft TVDss) and the well was drilled to a total depth of 9004ft MD (8824ft TVDss).

The process of extracting hydrocarbons from shale requires the rock around a well-bore to be shattered by hydraulic fracturing to enhance the permeability of the rock and to enable economic hydrocarbon extraction rates to be achieved. The process follows the same principle as described above with a change in objective:

- Water injection into a conventional reservoir (such as the scheme proposed for the Pickering field) relies on high permeability to move fluids away from the well and to dissipate pressures quickly; fractures that do occur are a by-product that are generally modelled to ensure that they do not propagate.
- In a shale play, such as at Preese Hall, water is pumped into wells with the explicit purpose of generating fractures; the process relies on the low shale permeability to keep the fluids around the wellbore and hence to raise fluid pressure quickly to the fracture gradient, thus shattering the surrounding rock. The fracture events are frequently monitored by in-field geo-phones to establish the location and intensity of the fracturing.

A total of five fracture treatments were pumped into the Preese Hall-1 well, with the largest stage having a volume of 14,000 barrels of water. Seismic events were observed after two treatments; two events were reported by the British Geological Survey (magnitudes 2.3 and 1.5) and 48 much weaker events were detected. The observed events were two to four orders of magnitude stronger than normally observed from hydraulic fracturing induced seismicity and it is clear that the mechanism that generated those events was different to the intended process.

The events surrounding the Preese Hall earthquake have been reviewed in detail (De Pater and Baisch, 2011; Green et al., 2012), and the accepted hypothesis is that the fluid injection connected with an existing fault leading to reactivation and movement along that fault plane.

The process that is thought to have happened is that during the fracture treatments, the wellbore connected with the existing fault which had greater hydraulic permeability than the surrounding shale. The pumped water then flowed preferentially into and along the fault plane rather than initiating new fractures as was intended. The low permeability of the shale on either side of the fault plane did not allow the fluids to dissipate into a large volume, but continued to spread over along the fault plane.

Although the pressure level became smaller with time and distance, there was still sufficient overpressure to cause fault slip at a significant distance from the well. The two large events recorded by the BGS displayed almost identical characters, leading investigators to believe that the fault had failed at exactly the same point on both occasions.

In the presented fault model, the high pressure fluid spread along the fault plane until it reached a point that had a failure stress level that was lower than for the surrounding rock, i.e. the frictional strength at that point would have been lower than for neighbouring sections along the fault plane. The raised fluid pressure triggered a local failure, and hence local movement on the fault. The resulting elastic movement would then have been transmitted to neighbouring areas of the fault plane, triggering movement at those points where the fluid pressure had reached the minimum horizontal stress. In total, an area of approximately $10{,}000m^2$ is thought to have moved, causing the measurable seismic event. The whole fault should be subject to the same regional stresses, so the limiting factor on the area of the fault that actually moved was whether the pumped water had reduced the minimum effective stress at any given point to, or close to, zero.

In conclusion, the water injected at high pressure into Preese Hall-1 was deliberately designed to cause hydrofracturing of the impermeable shale rock. However, the water unintentionally entered a nearby pre-existing naturally occurring fault, raising the fluid pressure along the fault plane until fault movement occurred. In contrast, the proposed scheme for EMS-1 is designed to inject water into the permeable reservoir sand at relatively low pressure, preferably without fracturing the rock around the wellbore (see section 4).

4. Ebberston South-1 (EMS-1) Water Injection Scheme

Third Energy intends to produce gas from the Kirkham Abbey Formation (KAF) within the Ebberston South gas discovery in a scheme that will also produce up to 3,500 bpd of highly saline water, although the reservoir model predicts considerably lower rates. The proposed scheme includes disposal of the produced water into the Sherwood formation in the EMS-1 well. The scheme is conventional and the injection rates and pressure are not designed to induce hydrofracturing of the rock.

EMS1-1 was drilled in 2009 and encountered 1,448ft of Sherwood sandstone at a depth of 2657ft TVDss (Figure 4-1). The Ebberston South field area is not structurally complex, and there is no evidence that the EMS-1 well encountered any faults, although the risk of large-scale fault compartmentalisation remains. Consequently, the potential risk for water injection to cause fault reactivation, and hence seismic activity via the following mechanisms requires evaluation:

1. direct injection into a fault plane, i.e. in a manner similar to the Preese Hall-1 event;
2. an increase in compartment fluid pressure that breaches the fracture gradient.

4.1. The Sherwood Formation

The Sherwood Sandstone Group, also known as the Bunter Sandstone, is widespread in and around Britain. The formation was deposited during the late Permian and Triassic periods, and predominantly comprises sandstone and pebbly sandstone with lesser amounts of conglomerate and minor amounts of mudstone and siltstone. It is present in several different sedimentary basins in the UK, including the Carlisle, Cheshire and West Lancashire, Worcester, East Yorkshire and Lincolnshire and Wessex basins.

The Ebberston South field sits within the Cleveland basin where the Sherwood Formation is typified by fine to medium grained sandstones, with local pebble beds and common argillaceous beds and lenses. The sediments are largely fluviatile in origin, but aeolian deposits, marls and breccias also occur. The formation is approximately 1000-1400 feet thick across the basin, although many wells penetrate thinner intervals due to fault cuts.

The formation is an important hydrocarbon interval in the East Irish Sea and Southern North Sea Gas Basins, but no commercial hydrocarbon accumulations have been found in the Cleveland Basin. As a consequence, little data have been collected locally, and sufficient variability in depositional environment ensures that data from the East Irish Sea and North Sea cannot be considered as completely representative. However, porosity-permeability relationships can be extrapolated with caution, particularly when the different depositional environments can be identified (Figure 4-2; Yaliz & McKim, 2003).

Third Energy has evaluated local wells with sufficient data and has established a range of reservoir properties. Across the Cleveland Basin, the Sherwood sandstone has an average net-to-gross of approximately 75-80% and an average porosity in the 11-20% range (Table 4-1); the range can be refined by consideration of current depth due to compaction (Figure 4-3).

		Porosity Range			
	Net To Gross	P90	P50	P10	Mean
Fordon-2	0.83	0.14	0.17	0.21	0.17
Caythorpe-2	0.47	0.075	0.12	0.15	0.12
Hunmanby -1	0.74	0.09	0.21	0.26	0.20
Malton-1	0.87	0.14	0.21	0.25	0.20
Marishes-1	0.89	0.12	0.16	0.19	0.16
Marishes-2	0.62	0.11	0.17	0.20	0.16
Rudston-1	0.80	0.14	0.2	0.25	0.20
Rudston-2	0.88	0.10	0.15	0.18	0.14
Pickering-1	0.95	0.10	0.13	0.15	0.13
Ebberston Moor-2	0.79	0.08	0.12	0.17	0.12
Lockton-6	0.97	0.08	0.12	0.16	0.12
Wykeham-1	0.77	0.06	0.12	0.16	0.11
All wells	0.78	0.10	0.15	0.20	0.15

Table 4-1 Average petrophysical parameters calculated for the Upper Sherwood Formation

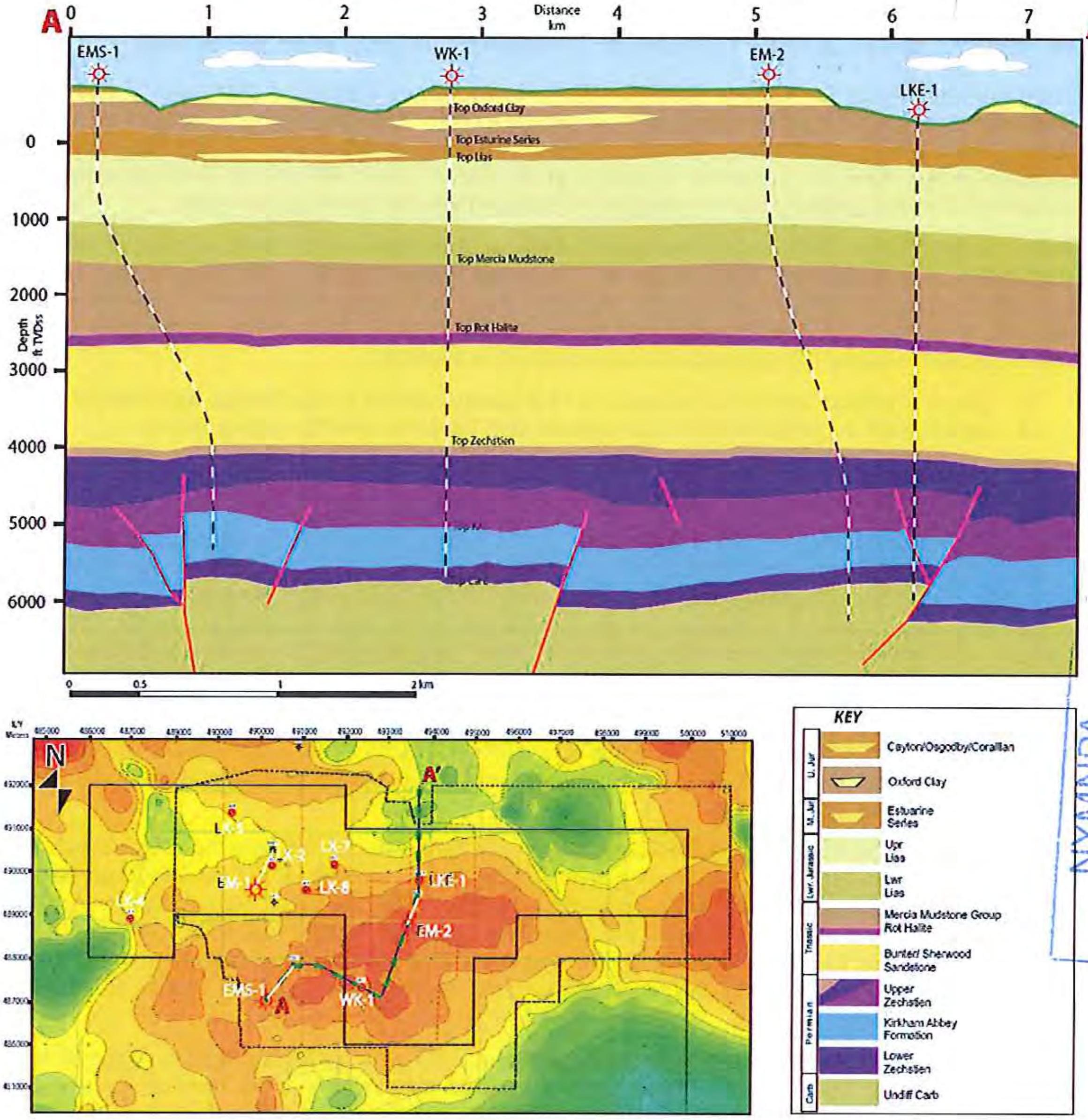


Figure 4-1 Ebberston South-1 geoseismic section

Wireline logs were not run across the Sherwood Formation in EMS-1, so petrophysical properties cannot be derived for the well. However, Ebberston Moor-2 (EM-2), which was drilled approximately 2km from EMS-1 in 2013 (Figure 4-1), did acquire relevant data (Figure 4-4), yielding an average porosity of 12%, with a net-to-gross of 79%. These values are consistent with values obtained from other wells drilled in the area (Figure 4-5 and Table 4-1), and hence they are a reasonable estimate of the properties of the Sherwood sandstone in EMS-1.

By analogy with the fluvial elements of the East Irish Sea, the average porosity range equates to an anticipated average permeability range of 10-200mD, with a base case expectation around 25-80mD. MDT measurements from the Sherwood Formation in the EM-2 well provided mobility values that can be used to estimate the permeability at the sample points; a range of 4-98mD with an average of 48mD generally supports the analogue information. Other facies elements (e.g. aeolian) yield a higher estimate of average permeability (Figure 4-2).

The Ebberston South field structure (Figure 4-6) is covered by 3D seismic, and is not structurally complex. The general structure is a gentle 4-way dip-closed anticline, with no seismically resolvable faults (i.e. with a throw greater than 30ft) at the Sherwood level (Figure 4-1).

Ebberston South-1 is a deviated well that encounters the Sherwood Formation at a depth of 4139ft MD (2657ft TVDss or 3106ft TVDgl), and penetrates 1448ft MD (1099ft TVD) of formation before exiting into the underlying Zechstein (Figure 4-1).

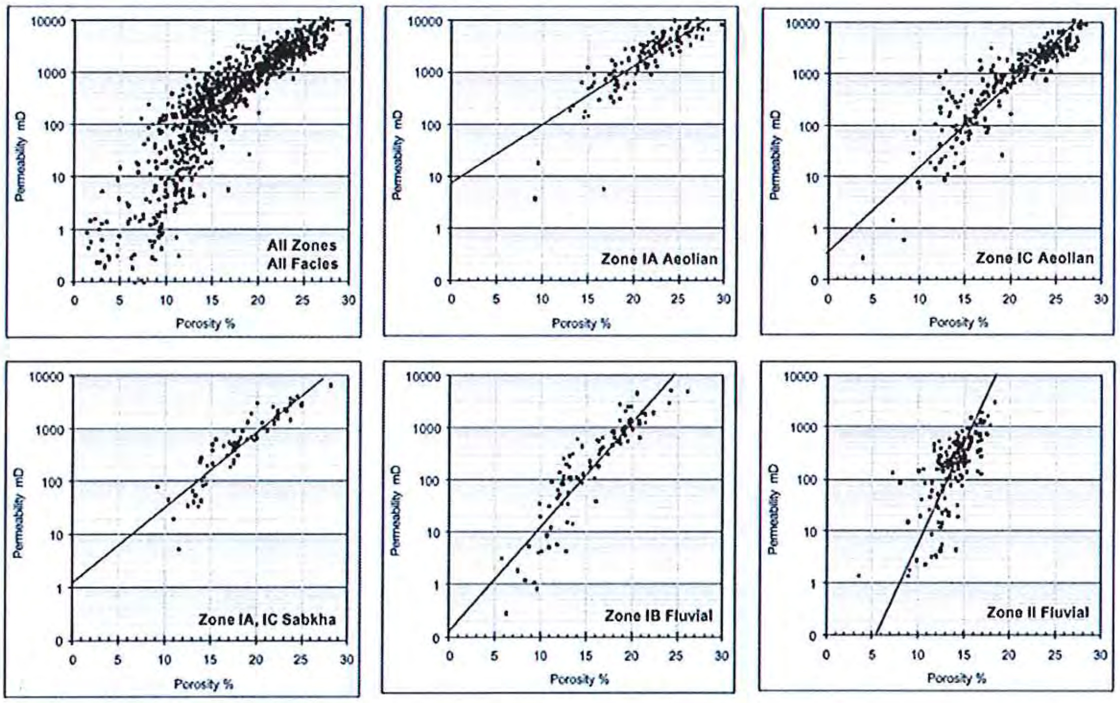


Figure 4-2 East Irish Sea poro-perm relationships for the Sherwood Fm. (Yaliz & McKim, 2003)

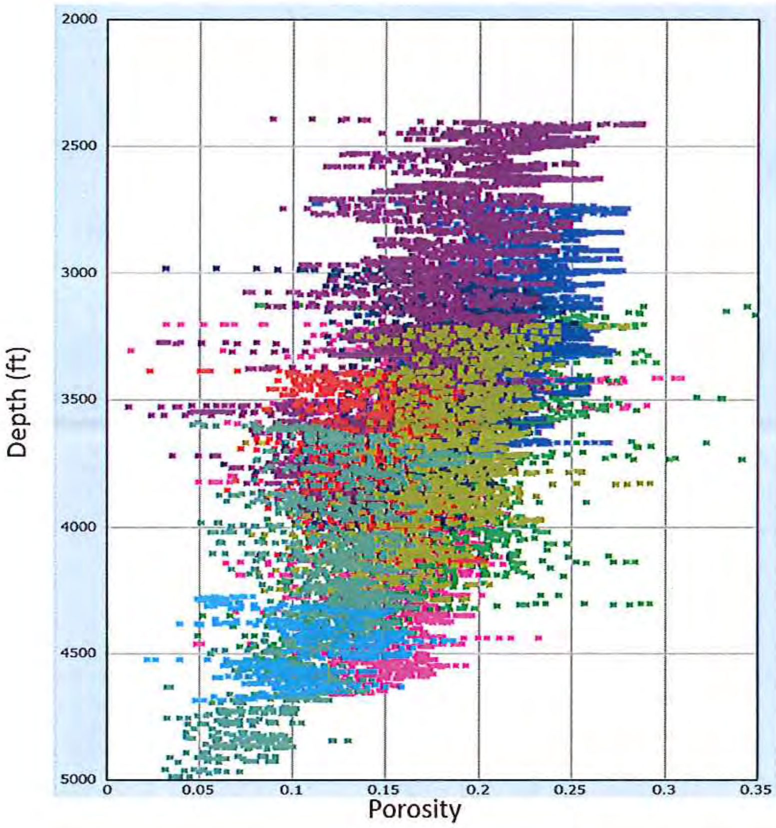


Figure 4-3 Porosity vs depth (Sherwood Formation, all Cleveland basin wells)

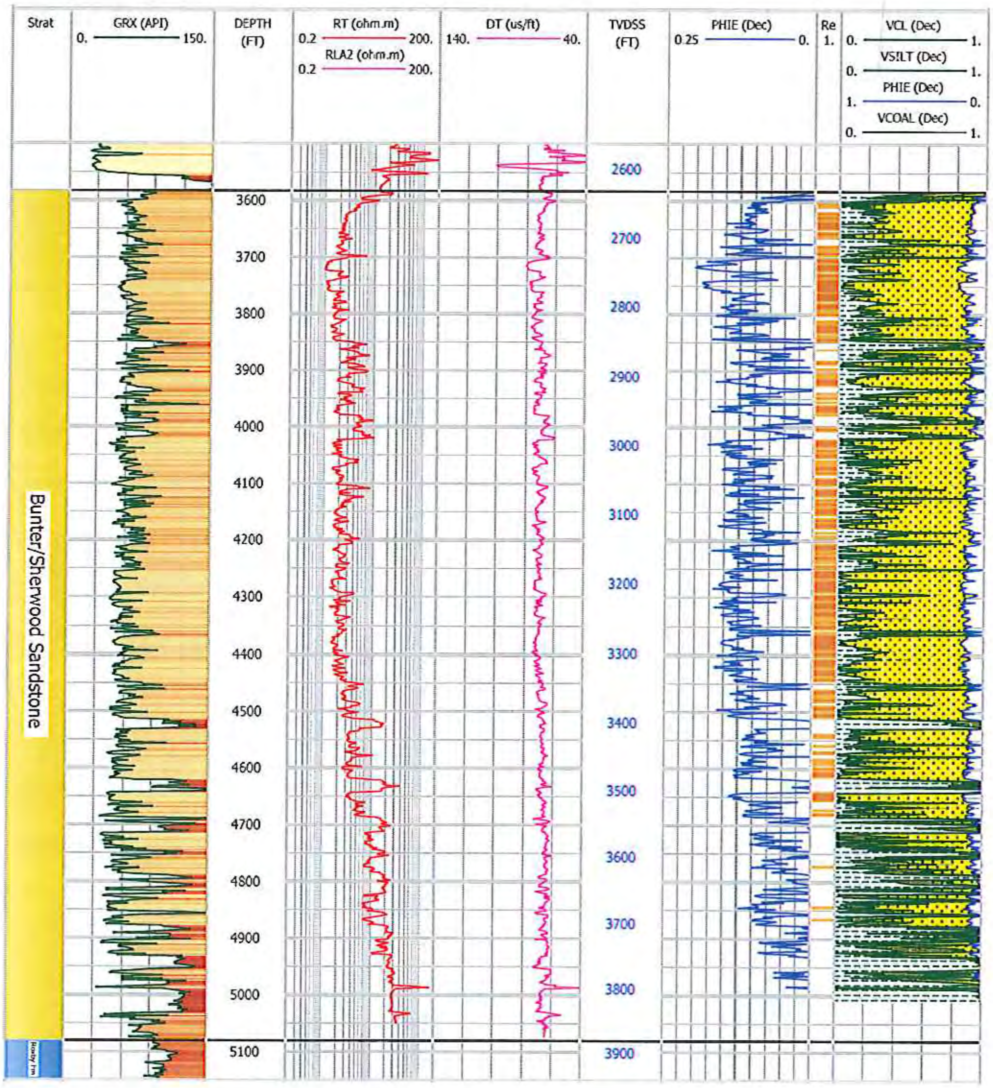


Figure 4-4 EM-2 CPI for the Sherwood Formation

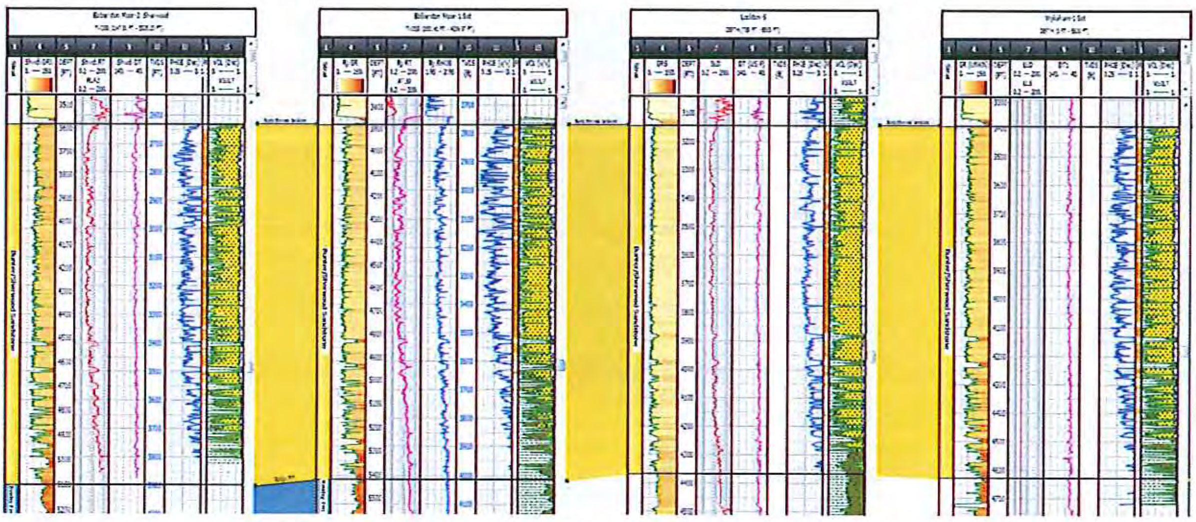


Figure 4-5 Correlation of the Sherwood Formation across the Ebberston South area

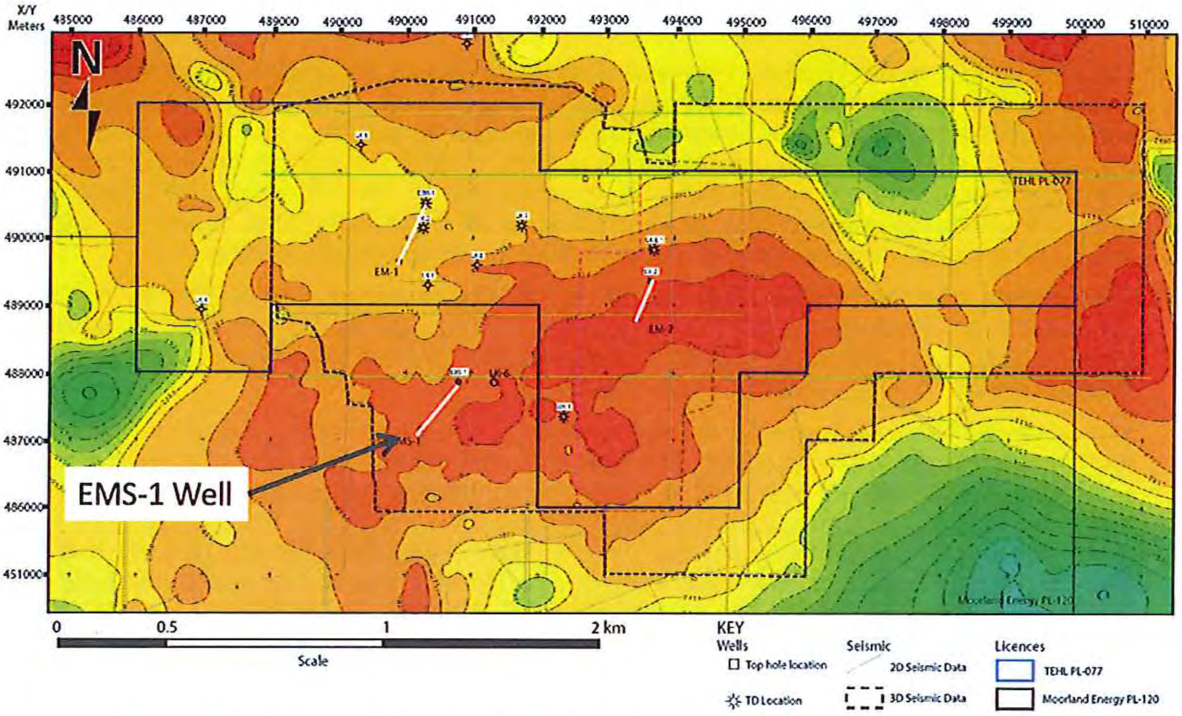


Figure 4-6 Top Sherwood Formation structural map over the Ebberston South structure

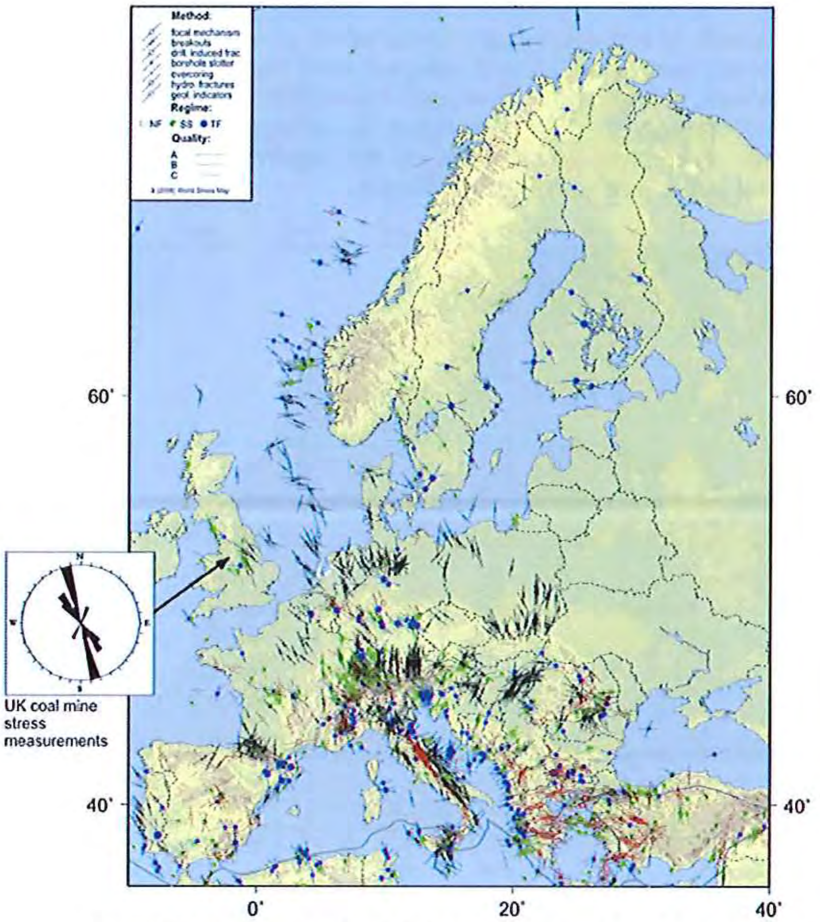


Figure 4-7 Measured horizontal stress map of western Europe

4.2. Fracture Gradient Assessment

The western part of the European continent is currently subject to a compressional stress regime due to the ongoing collision between Europe and Africa (Figure 4-7). Third Energy has analysed borehole breakout patterns within the Cleveland Basin and confirmed that the local stress regime is characteristic of the general European stress regime, so that the present day maximum horizontal stress component is oriented in a NNW-SSE direction (Figure 4-8). However, the largest horizontal stress is less than the overburden (or vertical) stress for all depths of interest. So, $\sigma_1 = \sigma_V$, and σ_3 is the minimum horizontal stress component which is oriented in an ENE-WSW direction.

Consequently, the faults most likely to fail are normal faults running parallel to the maximum horizontal stress direction (i.e. NNW-SSE). However, the distance from active plate boundaries means that the area is not critically stressed, and consequently related seismic events are rare, although seismicity linked to mining activity is more common.

As discussed in Section 2.3, an estimate of the minimum stress component, or fracture gradient, can be established from leak-off tests (LOTs). The tests that have been performed within the Cleveland basin have been collated and are presented in Figure 4-9. As detailed previously, the analysis requires rock failure information that is specifically supplied by a LOT. Formation integrity test (FITs) do not necessarily provide that information and the maximum tested pressures are typically less than the minimum stress component. The data presented in the well reports are not consistently clear on whether the conducted test reached a definite leak-off, although the most recent wells (e.g. KM-5 and KM-6) certainly applied FITs rather than LOTs.

In 2013, Third Energy commissioned GeoScience Limited to undertake a borehole stability study in support of a proposed KM-H well (GeoScience, 2013). As part of the study, GeoScience Limited assessed the stress system in the Cleveland Basin and generated stress-depth relationships for the minimum and maximum horizontal stresses as well as the fluid pore pressure (Figure 4-9). Those relations are not contradicted by the LOP and FIT data, although it must be recognised that a margin of error remains.

As there is no evidence of vertical compartmentalisation of overpressures within the basin, the lowest trap integrity, i.e. the point at which rock failure is most likely to occur, is at the top of the reservoir unit. In the EMS-1 well, the top of the Sherwood is at 4139ft MD (2657ft TVDss or 3106ft TVDgl), where the expected pore pressure is ~1200 psia based on extrapolation from measurements in EM-2. The maximum principal stress (the overburden) at this depth is approximately 3100 psia, while the minimum horizontal stress is no lower than 2385 psia.

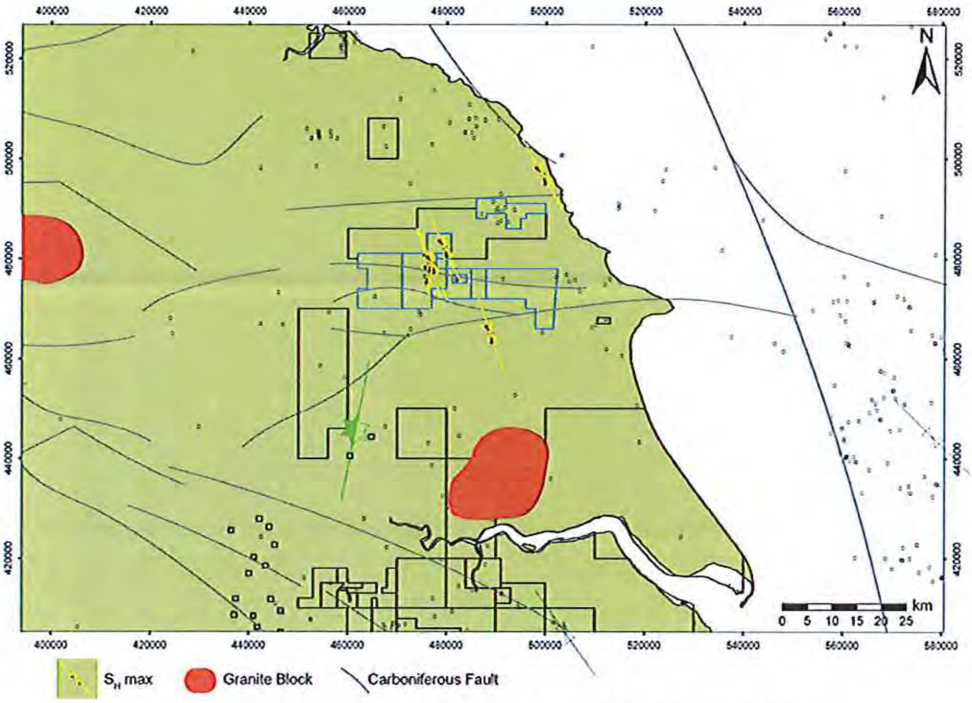


Figure 4-8 Measured horizontal stress map of the Cleveland Basin

Mohr circle analysis shows that existing fractures will open hydraulically when the formation fluid pressure reaches the minimum horizontal stress (i.e. at a pressure greater than 2385 psi). Shear failure can occur at lower fluid pressures, but requires existing faults or fractures to be optimally oriented for movement to occur (i.e. dipping at 60°, with an NNW-SSE orientation). If fractures are oriented at a different angle, higher fluid pressure will be required to cause movement on those planes, or to overcome the tensile strength of the rock and generate new features. Such considerations mean that in most instances, the minimum horizontal stress represents the local failure point.

However, in order to maintain a conservative approach, a lowermost fracture point of 2200 psia should be considered, yielding a drilling margin, or trap integrity, of ~1000 psi. So, to avoid the risk of breaching the fracture gradient and potentially causing a seismic event, water should be injected into EMS-1 at a bottom-hole pressure no more than 1000 psi above the initial formation pressure.

4.3. Injectivity Assessment

A Prosper model of the EMS-1 injection scheme was built to assess the impact of injecting water into the Sherwood Formation. The model calculates the expected flow-rate for a given set of parameters (formation permeability, injection interval, fluid viscosity, wellbore dimensions, etc.). The results are presented in Figure 4-10, Figure 4-11 and Figure 4-12, and are based on a conservative set of parameter assumptions.

The current working design uses an ESP across the Kirkham Abbey Formation that delivers water to the Sherwood Formation via the well annulus. The ESP configuration has not been finalised, but is expected to deliver an equivalent tubing-head pressure (THP) of 20-30 bara (290-435 psia).

Figure 4-10 shows the injection rates that should be achieved for any given THP for different reservoir permeabilities. There is clearly a non-linear relationship, which is due to the slim well completion and frictional losses; as the flow rate increases, the effective bottom-hole pressure (BHP) decreases (Figure 4-11). Consequently, the maximum injection rate that is likely to be achieved via an unaugmented ESP is 3000-3500 bpd.

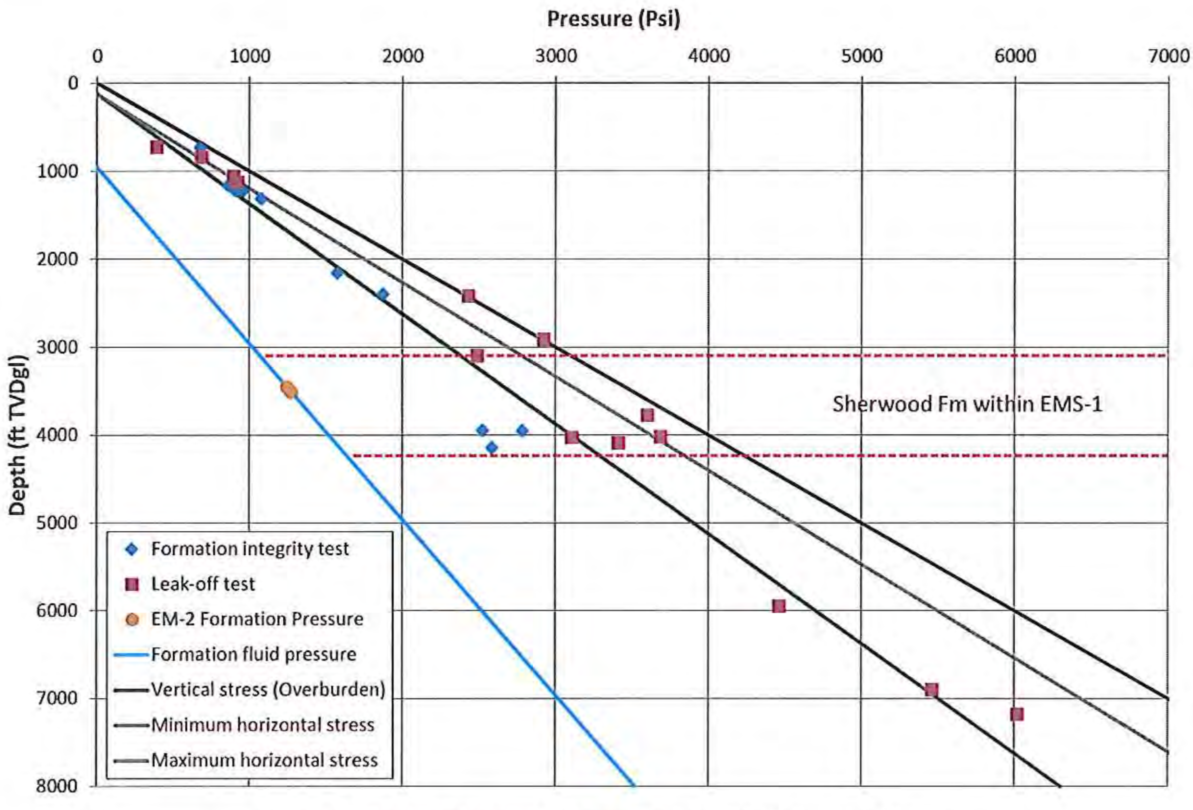


Figure 4-9 Stress data and relationships for the Cleveland Basin

Once the frictional losses are removed, the relationship between delivery pressure and injection rate is much simpler. There is a linear relationship, controlled by permeability (Figure 4-12), between the rate achieved and the difference between the BHP and formation pressure. As discussed in section 4.2, to safely remain below the fracture gradient, the BHP must not exceed the initial formation pressure by more than 1000 psia. The plot shows that as long as the average permeability of the formation is greater than 5mD, EMS-1 should be capable of injecting up to 3,500 bpd without risk of breaching the fracture gradient.

If the average reservoir permeability is less than 5mD, the injection rate would have to be limited to ensure that the fracture gradient is not exceeded. However, the THP required to achieve high rates at such permeability levels (Figure 4-10) is high, and such a scenario can be mitigated by ensuring that the pump design is incapable of reaching such levels.

While the range of permeability within the reservoir undoubtedly includes tight rock (see section 4.1), all the available data indicate that the average reservoir permeability is at least 10mD, and is probably in the 25-80mD range. Consequently, it is extremely unlikely that the ESP will generate a BHP that will exceed the local fracture gradient.

The injection pressure raises the formation pressure around the wellbore, and that excess pressure dissipates away from the well bore. Figure 4-13 shows how the fluid pressure drops with distance from the well for different permeabilities in a scenario where a flow rate of 3500 bpd is achieved. This is indicative of the maximum distance for fractures or faults to be activated due to the direct transient pressure increase related to fluid injection. In practice, hydrofracture formation reduces the skin, and hence the required injection pressure, which in turn reduces the effective radius.

The radius of elevated fluid pressures can be translated into an effective area which can in turn be used to estimate the maximum seismic event that could result. In the scenario presented in Figure 4-13, the formation pressure in rock with an average permeability of 1mD will fall below the fracture stress no more than 30ft from the well, so that a maximum area of approximately 250m^2 around the wellbore will be subjected to formation pressures above the fracture gradient.

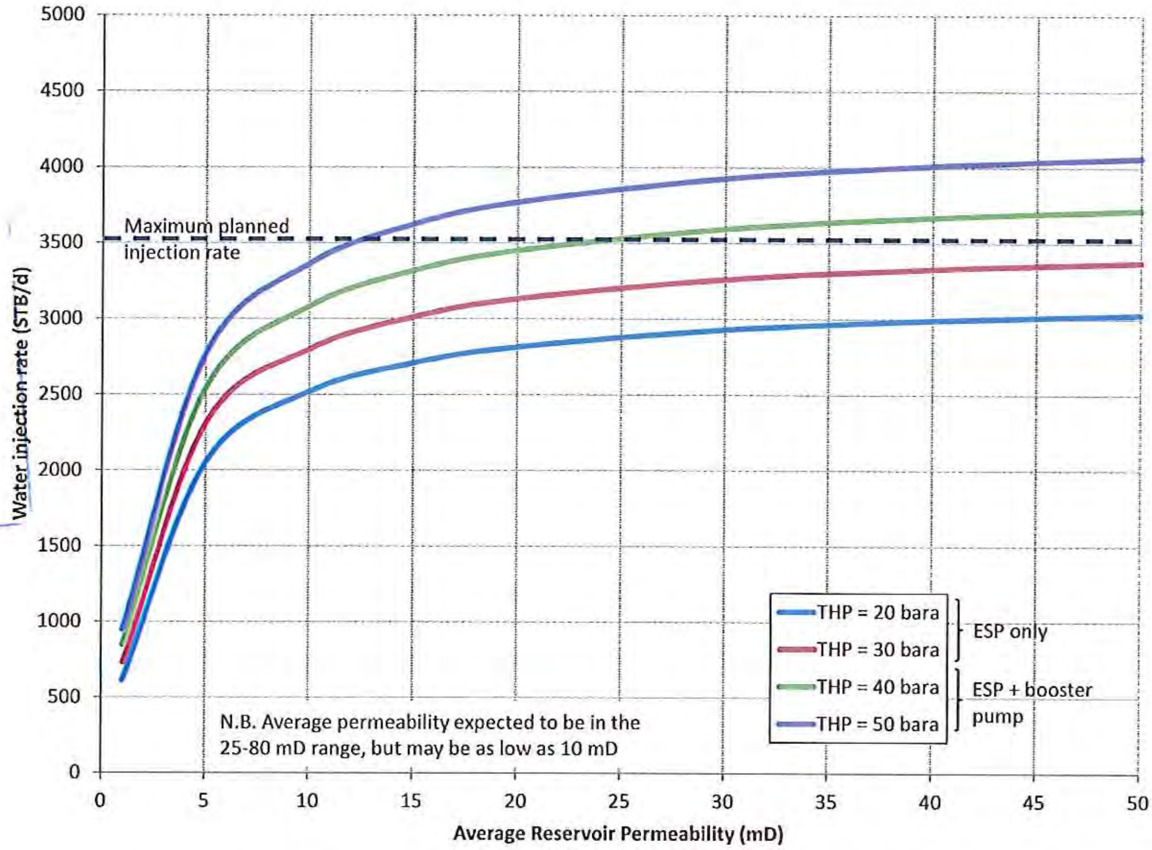


Figure 4-10 EMS-1 Injectivity assessment: injection rates achieved for different THP's

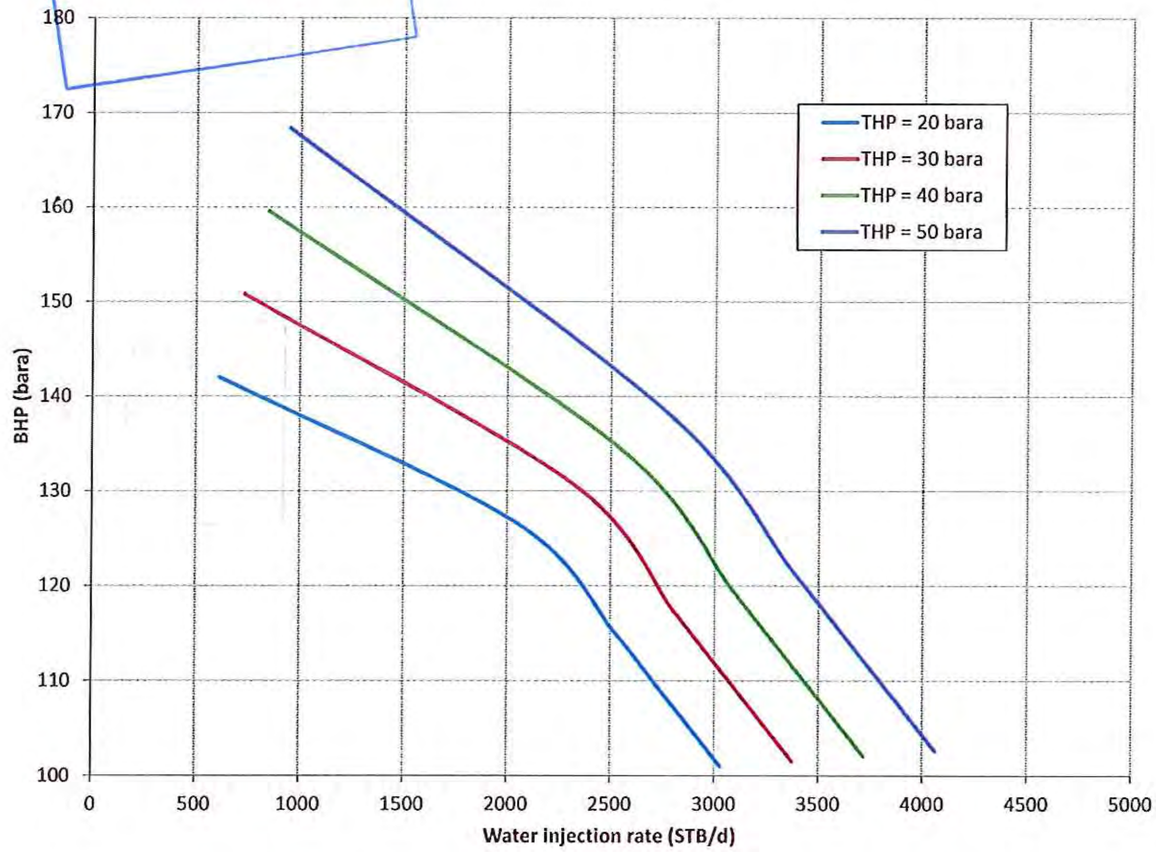


Figure 4-11 EMS-1 Injectivity assessment: the effect of injection rate on BHP

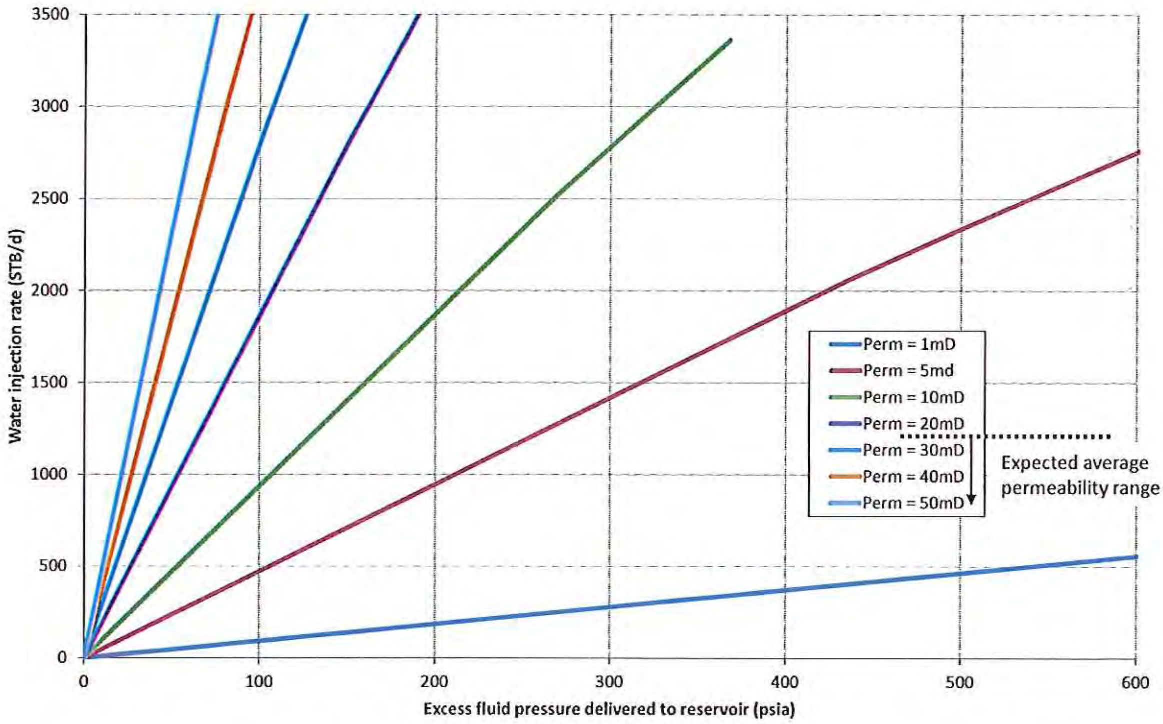


Figure 4-12 EMS-1 Injectivity assessment: injection rate vs. excess fluid pressure in wellbore

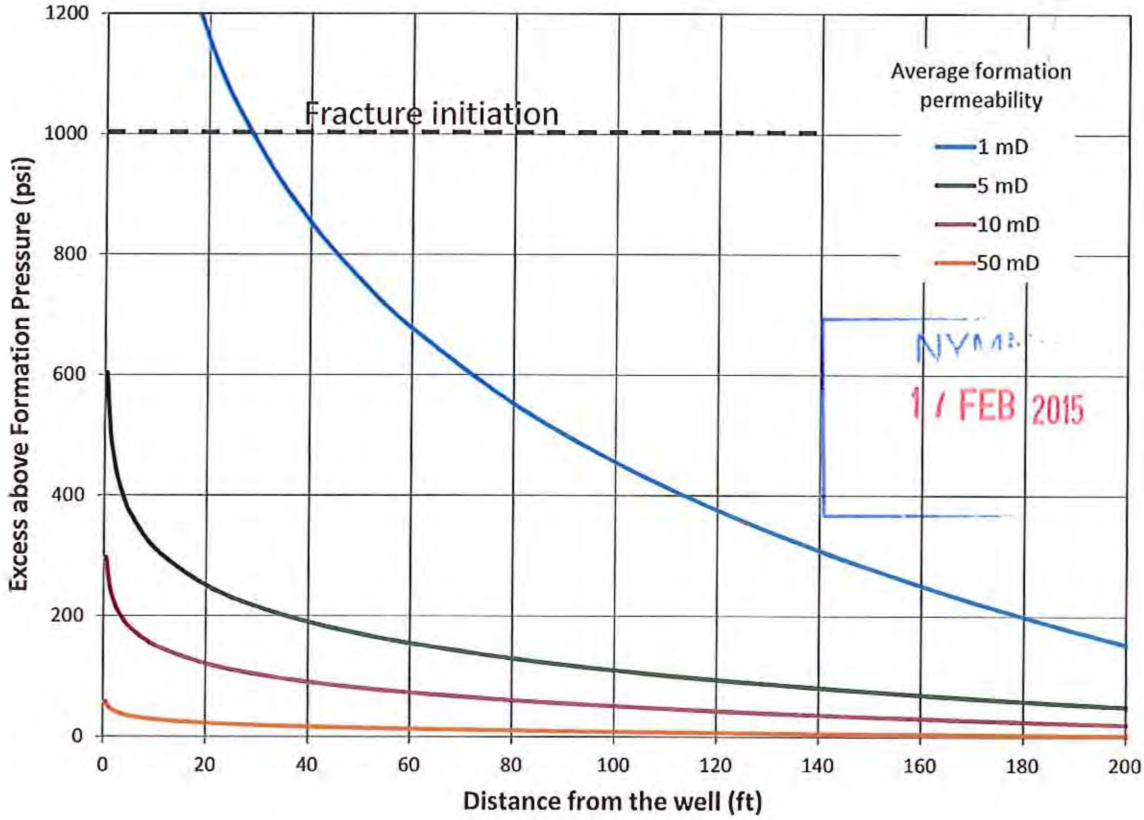


Figure 4-13 Formation pressure dissipation for a constant 3,500 bpd injection rate

As discussed in section 2.4, earthquakes with a magnitude below 2.0 are not "felt" except rarely by sensitive people. Meanwhile, DECC have implemented the traffic light system (Table 2-1), whereby seismic activity with a magnitude less than 0.0 will be considered acceptable, while anything above a magnitude of 0.5 will require activity to cease.

The Preese Hall event is estimated to have activated a fault area of 10,000m^2 to generate a 2.3 magnitude quake. By extrapolation, an earthquake with a magnitude of 0.5 requires fault movement over an area of approximately 20m^2, while a 0.0 magnitude earthquake could be generated by a fault slipping over approximately 4m^2.

Thus, with the conservative set of assumptions presented above, it is theoretically possible that if the average permeability in the Sherwood Formation is less than 2-3mD, then injection into EMS-1 at a rate of 3500 bpd has the potential to cause fault movement in the immediate vicinity of the well that will register in DECC's amber or red categories.

4.4. Pressure Compartments

Water is marginally compressible, and a pressure increase will cause the volume of a given mass of water to decrease; conversely, the mass of water can be increased while maintaining the same volume, i.e. the process involved during water injection.

An injection scheme causes the mass of water in a reservoir to increase while the container (the pore space) effectively remains the same size, leading to a pressure increase. If water is injected into an infinite aquifer, then the pressure increase will be vanishingly small, but as the size of the compartment decreases, the same volume of injected water will cause a correspondingly larger pressure increase. Consequently, it is theoretically possible to raise the formation pressure within a small compartment to the fracture pressure, hence triggering rock failure and potentially fault movement.

The Ebberston South structure is not structurally complex (Figure 4-6), with no seismically resolvable faults (i.e. with a throw greater than 30ft) at the Sherwood level, and no mapped fault compartments. Unless the faults in the Sherwood completely offset the reservoir (i.e. with an offset in excess of 1000ft), there is no evidence that the sand-on-sand faults are sealing or compartmentalise the reservoir. In the East Irish Sea, depletion due to hydrocarbon extraction from the Sherwood Formation has been detected over distances in excess of 12km, across multiple major faults.

Consequently, it is extremely unlikely that the proposed injection scheme would increase the fluid pressure within a reservoir compartment to a level sufficient to cause rock failure. Further, this mechanism is not instantaneous, involving pressure build-up over a period of time. A monitoring program will be able to measure any pressure increase, allowing the compartment size to be extrapolated and injection policy adjusted accordingly.

Additionally, there is an effective feedback mechanism. Under fixed injection conditions, the THP is constant, so as the formation pressure rises, the pressure excess presented by the well will fall. As a result, the injection rate will slow and eventually cease once the formation pressure matches the BHP. So, as long as the THP is set at a level that such that the static water column pressure does not exceed the fracture gradient, the only consequence will be curtailment of the injection.

4.5. Risk Assessment

The arguments presented above are based on a set of assumptions, each of which has an associated risk envelope, whereby there is a possibility that that assumption is invalid. For example, there is a small chance that a mistake will be made during the specification and manufacture of the ESP such that it is capable of delivering higher BHP's which have the potential to fracture the rock.

It is possible to assign probabilities to the various elements of the injection system, and hence to quantify the overall risk that the proposed scheme will cause a seismic event. The following parameters and assumptions have been considered as part of the risk assessment:

- As stated above, there is a possibility that the ESP may be installed with the capability of delivering a BHP in excess of the local fracture gradient, which might be capable of fracturing the rock without supplementation from a surface booster pump. If the effect of frictional losses is taken into account, the probability of this occurring is estimated at about 1 in 1000.
- The average rock permeability could be lower than the anticipated range of 25-80mD. Based on the data presented in Figure 4-2 and Figure 4-3, the chance of the average permeability falling below 10mD is estimated at 1 in 500, while the possibility of the rock having an average permeability below 5mD is thought to be less than 1 in 1000.
- The minimum horizontal stress evaluation has a large error range (see section 4.2 and Figure 4-9). The discussion above was based on a conservative assessment, but there is probably a 1 in 10 chance that the fracture pressure in the Sherwood Formation in EMS-1 is less than 2,350 psia. That probability falls with pressure, such that there is thought to be a 1 in 50 chance that the fracture pressure is less than 2,200 psia, and a 1 in 200 chance that it is less than 2,100 psia.
- The Sherwood Formation is thought to be hydraulically connected over large distances, as demonstrated in the East Irish Sea, with the sand-on-sand faults allowing fluid transmissibility. However, there is a 1 in 500 probability that there are faults around EMS-1 that are completely sealing, forming an effective compartment of restricted volume.
- Finally, there is probably a 1 in 200 chance that that the effective reservoir thickness is less than 100ft rather than the conservative 1000ft assumed in the earlier discussion. This particular risk can be mitigated by perforating the well through the entire Sherwood Formation interval within the well to maximise connectivity with the reservoir, in which case the probability would fall to less than 1 in 1,000.

None of these elements is sufficient in isolation to cause hydrofracturing and a seismic event. For example, if the permeability is less than 5mD (the level at which a magnitude 0.0 earthquake might occur), the planned ESP would still deliver a THP of 20-30 bara, which would result in reduced injection rates rather than rock failure. However, if that ESP had been subject to a specification or manufacturing error, then the BHP might be raised in an attempt to inject at the desired rate, leading to rock failure. If the permeability is as expected, the high BHP will not be required. So, it is only in combination that these factors, both with a 1 in 1000 chance, can cause a seismic event; the combined probability is 1 in 1,000,000.

Alternatively, the pressure required to cause fractures could be locally reduced to less than 2,100 psia, and the ESP operating envelope might reach this pressure. However, an average permeability below 5mD or a higher injection rate would still be required to cause the rock fracture; the combined probability is in the order of 1 in 200,000.

There are other possible scenarios, all of which require multiple elements to be significantly skewed from the expected or planned range, resulting in combined probabilities that range from 1 in 100,000 to 1 in 50,000,000. Hence, the possibility of the proposed injection scheme in EMS-1 causing a seismic event larger than 0.0 in magnitude is assessed as less than 1 in 100,000.

The analysis can be extended to consider the possibility of larger magnitude seismic events being caused by the injection scheme; magnitude 0.5 is the point at which DECC requires operations to cease, magnitude 2.0 is generally accepted as the threshold at which individuals can feel an earthquake, and damage to property can occur at magnitude 4.0 or higher (Figure 2-5). Because of the logarithmic nature of the Richter scale (see section 2.4), fault movement over a much larger area is required to cause a larger magnitude earthquake (see Table 4-2). Consequently, the parameters detailed above must be even more extreme.

So, by extension of these parameters, the probability of any given magnitude of seismic event being caused by the water injection into EMS-1 can be estimated. Table 4-2 summarises the approximate area of fault movement required to cause different magnitude earthquakes, along with the estimated probability of occurrence and the consequence of such an event.

Earthquake magnitude	Approximate area of fault movement	Probability of occurrence due to water injection in EMS-1	Consequence
>0.0	$4m^2$	<1 in 100,000	DECC allows water injection to proceed with caution, possibly at reduced rates. Monitoring is to be intensified.
>0.5	$20m^2$	<1 in 500,000	DECC requires water injection to be suspended immediately
>2.0	$5,000m^2$	<1 in 10,000,000	Earthquake may be felt at the surface by individuals
>4.0	$5,000,000m^2$	<1 in 100,000,000	Threshold at which minor structural damage may occur

Table 4-2 Seismic event risk: probability and consequence

In summary, the proposed scheme will inject small volumes water at low rates into a permeable sandstone. The pressure required to enable this injection is low compared to the pressure that would be required to fracture the reservoir. Consequently, the probability of the scheme causing a seismic event is extremely low.

5. Conclusions and Recommendations

The proposed water injection scheme for Ebberston South-1 is designed to dispose of produced water into the Sherwood sandstone. The Sherwood sandstone has sufficient porosity and permeability to accept large volumes of injected water.

Due to the relatively low planned injection pressures and injection rates, it is considered extremely unlikely that water injection could cause sufficient localised pressure increases to initiate hydraulic fracturing of the rock or movement on existing fault planes. It is therefore extremely unlikely that the proposed water injection scheme will cause any seismic events.

The slim well design will control the pressures delivered to the reservoir due to frictional losses at high injection rates. This will in turn limit the injection rate achievable by an ESP to 3000-3500 bpd unless a surface booster pump is installed.

Within the reservoir, average permeability is the key parameter affecting localised pressures around the injection well. Available data indicate the average reservoir permeability is at least 10mD and is probably in the range 25-80mD. If the average reservoir permeability is above 5mD as expected, water can be injected at pressures well below the fracture gradient for the full range of anticipated injection rates. For permeabilities below 5mD, lower injection rates will be achieved unless a booster pump is added.

Using worst-case scenario parameters, the BHP required to pump 3500 bpd could exceed the local fracture gradient if the average reservoir permeability is below 5mD. An average reservoir permeability of less than 2-3mD would lead to raised pressures over an area in excess of $5m^2$ around the wellbore, the level at which a seismic event of magnitude 0.0 may be generated. However, the planned ESP configuration will not be able to deliver a BHP high enough to exceed the fracture gradient, and hence the only consequence of lower reservoir permeability will be lower injection rates.

So, in order to minimise the risk of raising the BHP above the fracture pressure, it is recommended that the ESP should not be supplemented by a booster pump. In such a configuration, water injection at the proposed rates and pressures can proceed within DECC's "Green" category, and the likelihood that the injection scheme will cause a seismic event with a magnitude greater than 0.0 is assessed as less than 1 in 100,000.

Continued water injection will gradually increase formation fluid pressures. Therefore, a monitoring program is recommended to track formation pressures over the initial test period, providing data that can guide future injection strategy decisions.

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