EBBERSTON MOOR

WATER INJECTION:

SEISMIC EVENT RISK ASSESSMENT

CLIENT:

THIRD ENERGY

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RESOURCES

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Executive Summary

Third Energy is planning to develop the Ebberston Moor, Ebberston South and Wykeham gas discoveries in North Yorkshire, onshore United Kingdom. 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 overlying Sherwood sandstone formation.

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 failure point, then fracturing or fault movement could occur, 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 Ebberston Moor field area is not structurally complex, but faults do intersect the Sherwood formation regionally. Consequently, water injection could cause fault reactivation, and hence seismic activity, via one of the following mechanisms:

- direct injection into a fault plane;
- an increase in reservoir fluid pressure that breaches the fracture gradient.

The Sherwood sandstone has sufficient porosity and permeability to accept large volumes of injected water, and the injection pressures required to achieve the planned injection rates are relatively low.

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 10mD, water can be injected at pressures well below the fracture gradient for the full range of anticipated injection rates. For permeabilities below 10mD, lower injection rates will be achieved unless the injection pressure is raised to levels that may cause seismic activity.

The proposed scheme will inject a significant volume of water into the Sherwood over the life of the field, which will raise the ambient reservoir pressure of the formation in the Ebberston Moor area. The magnitude of the pressure increase is a function of the volume of reservoir connected to the injection wells, and although faults have been mapped around Ebberston Moor, they are not expected to compartmentalise the reservoir. Consequently, the base case development scheme will inject a volume of water that is extremely unlikely to raise the regional formation pressure in the Sherwood formation to levels that might trigger a seismic event.

In conclusion, the proposed injection scheme should incorporate a maximum pump design that ensures that the excess pressure applied to the rock around the well is lower than the minimum rock failure pressure. 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 50,000.

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1. Introduction

Third Energy holds and operates several exploration and production licenses in North Yorkshire, onshore United Kingdom (Figure 1-1). The Ebberston Moor field, formerly known as Lockton, was discovered in 1966 by well Lockton-2a, which encountered sour gas in fractured Kirkham Abbey (KAF) carbonate reservoirs. The Lockton field was developed and brought on production in May 1971, but was abandoned in 1972 due to early water production the field.

Subsequent to the cessation of production, Wykeham-1 found gas in a separate structure to the south of Lockton, but it produced water when tested and was deemed to be uncommercial. In 2007, Ebberston Moor-1 was drilled to the north of Lockton-2a and tested gas and water from KAF reservoirs. More recently, Ebberston South was drilled to the west of Wykeham-1 and was successfully tested without water.

A re-interpretation of reprocessed seismic data acquired over the fields in 2007 indicates that large areas of gas remain un-tapped and confirms hydrocarbon separation of the Ebberston Moor reservoir from the Wykeham/Ebberston South complex (Figure 1-2).

The KAF reservoir has a low permeability matrix with a high permeability fracture network throughout. This dual permeability system encourages the early breakthrough of water under conventional production mechanisms. Third Energy intends to combat this process by actively pumping the water out of the KAF reservoir and injecting it in the overlying Sherwood Sandstone for disposal, hence allowing gas in the tight matrix to mobilise through de-pressurisation.

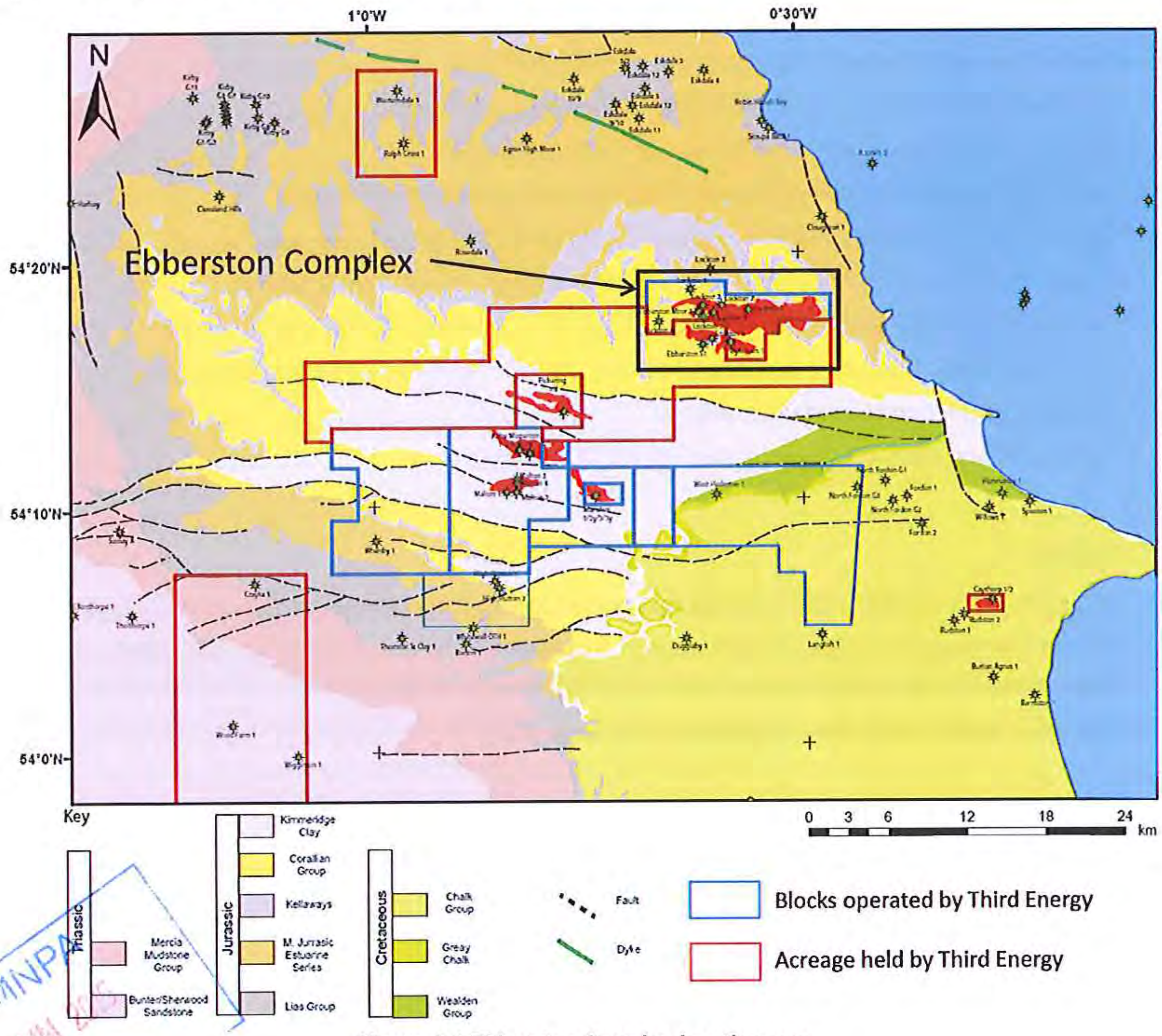

Figure 1-1 Ebberston Complex location map

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 Complex area is not structurally complex, but seismic interpretation shows that faults exist. 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. by injecting into a fault), 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.

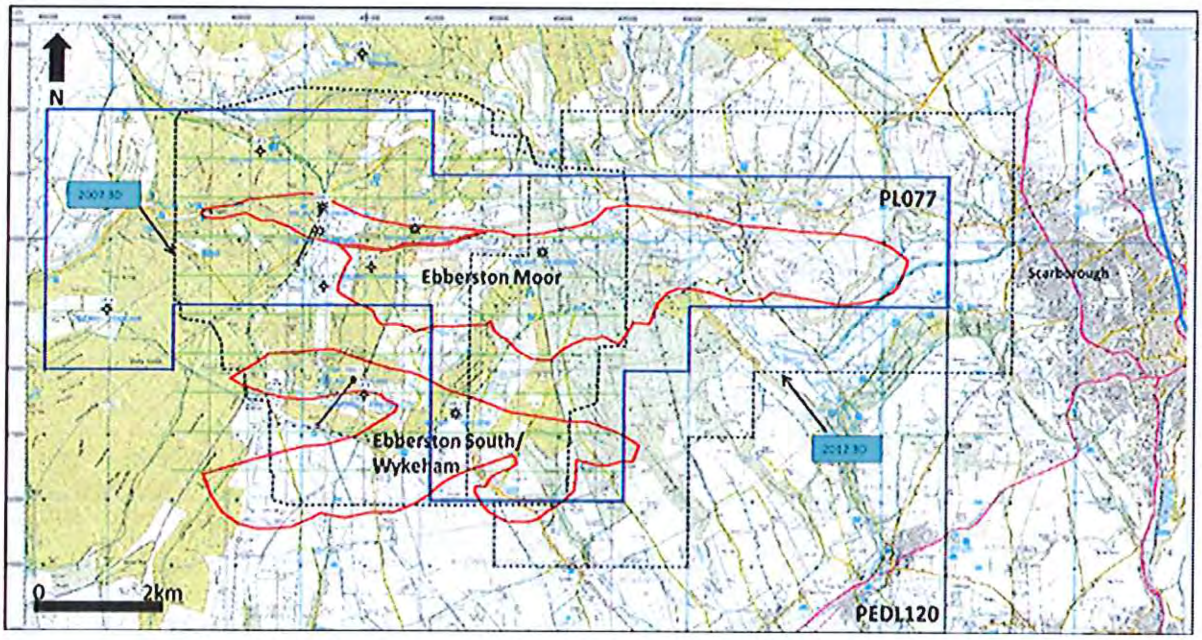

Figure 1-2 Ebberston Moor, Ebberston South/Wykeham (Ebberston Complex)

2. Background Discussion

In order to frame the assessment of the risk associated with water injection, 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 is zero and should not be incorporated in failure calculations.

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).

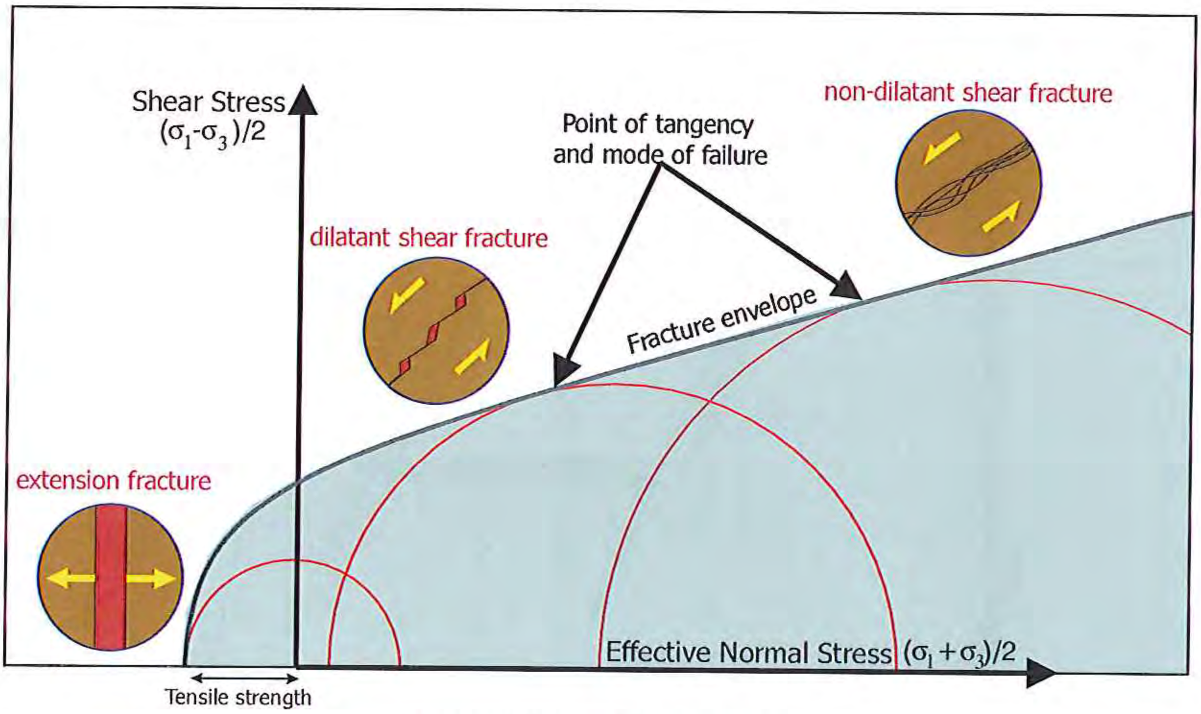

Figure 2-1 Mohr seal failure criteria

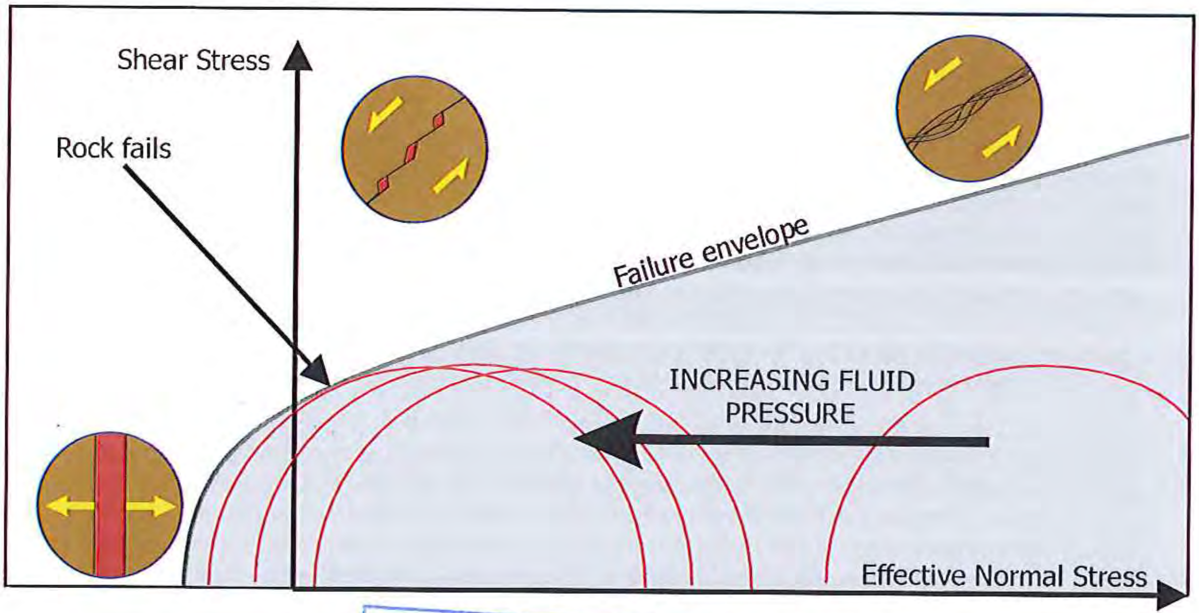

Figure 2-2 Effect of increasing fluid pressure

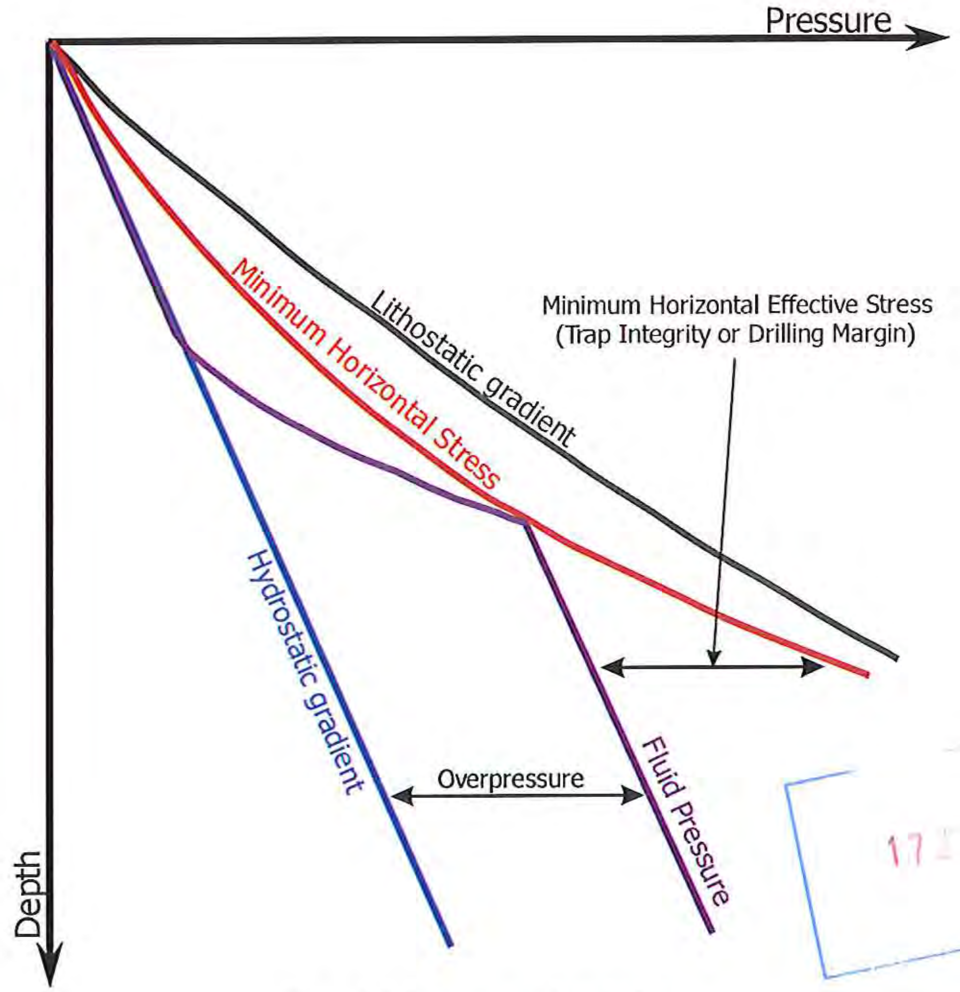

Figure 2-3 Overpressure terminology

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 ±200 psi and may reach ±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.

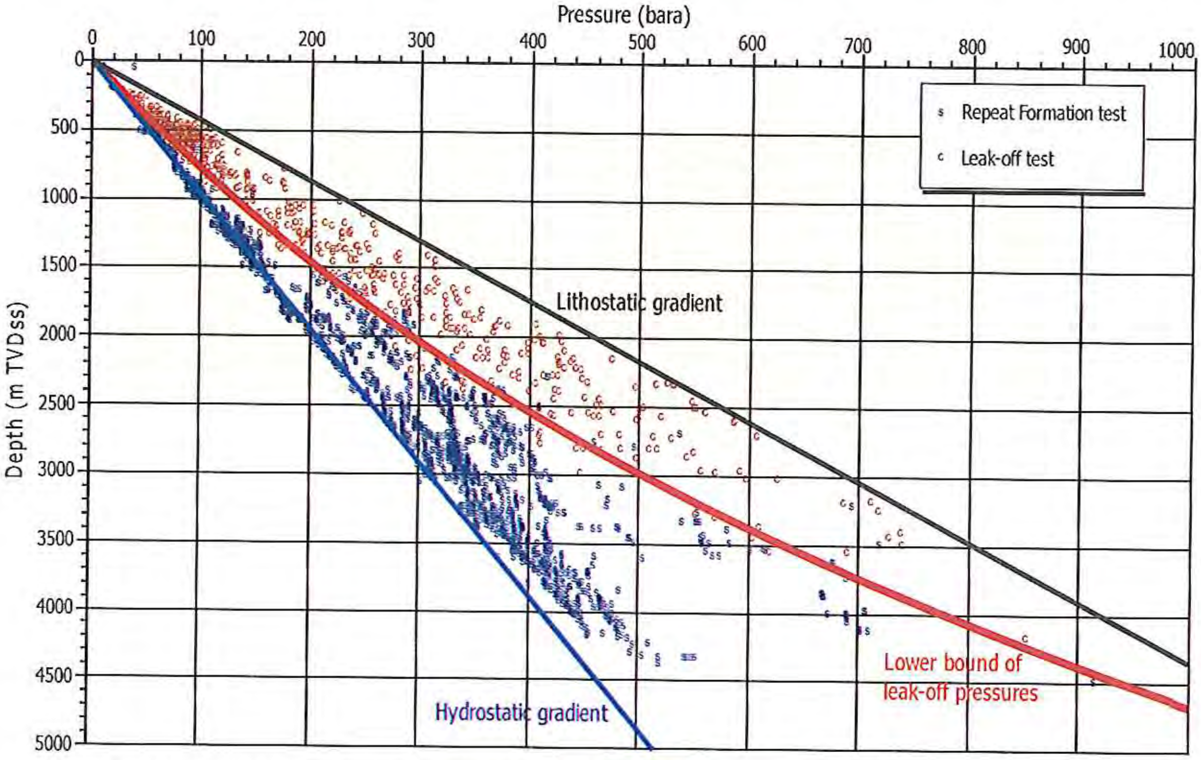

Figure 2-4 An example from the North Sea of regional fluid pressure and LOT data vs. depth

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:

$$M_0 = GAd$$

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 (magnitude up to 2.3, 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

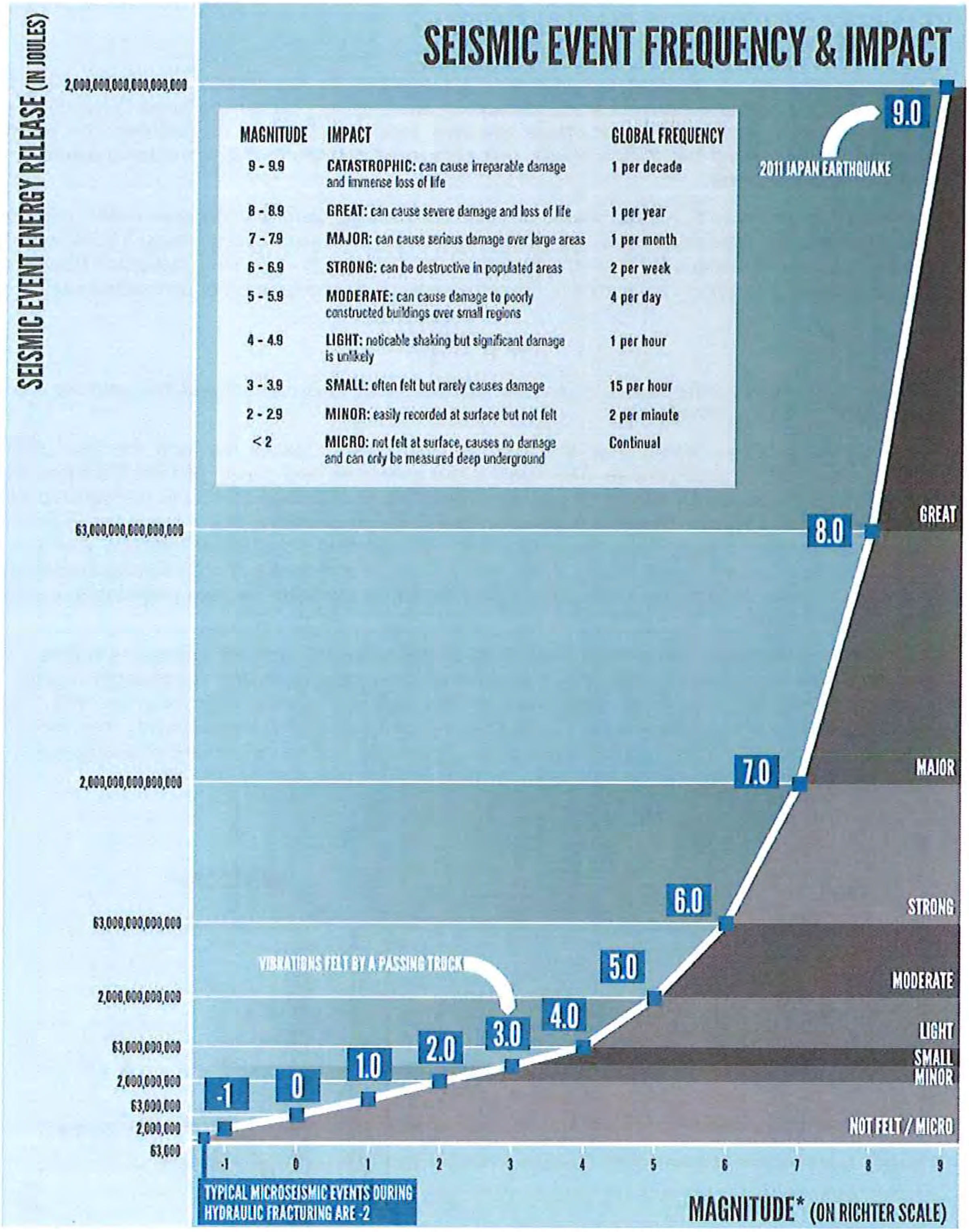

Figure 2-5 Seismic Event Frequency and Impact (source: USGS)

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.

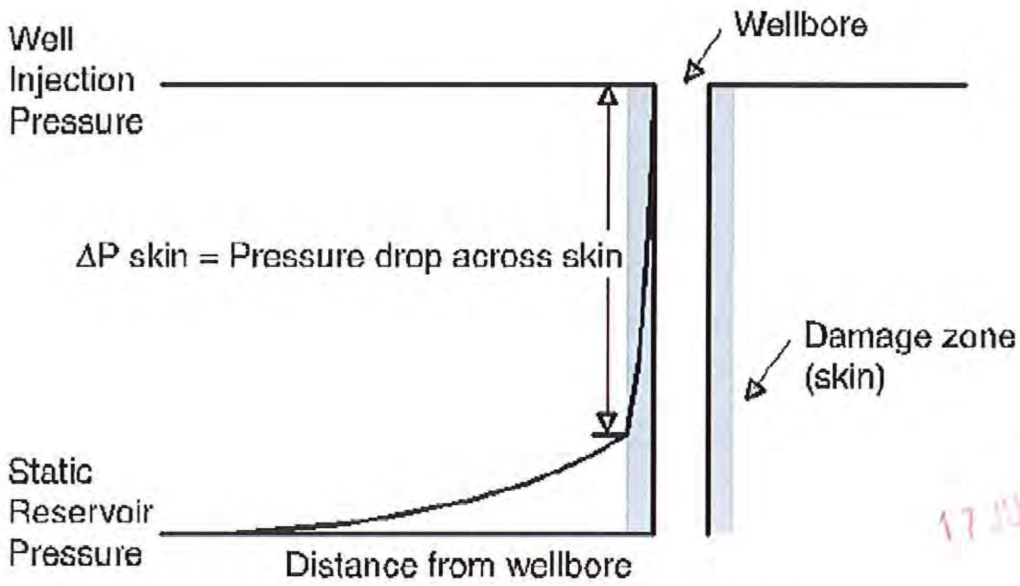

Figure 3-1 The pressure distribution around the wellbore of an injection well

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 Ebberston Moor 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 Moor Water Injection Scheme

Third Energy plans to produce gas from the Kirkham Abbey Formation (KAF) within the Ebberston Moor, Ebberston South and Wykeham gas fields (Figure 1-2). Highly saline water will be produced in conjunction with the gas at a rate of up to 12,000 bpd (Figure 4-1), and Third Energy proposes to inject the produced water for disposal into the Sherwood formation (Figure 4-2).

The proposed scheme includes injection of up to 3,500 bpd of water into well Ebberston South-1 (EMS-1). The remaining volume (up to 8,500 bpd) will be injected into the Sherwood formation via the annulus of well Ebberston Moor-1 (EM-1) or by a dedicated new well that will be drilled close to EM-1.

The Ebberston Moor field area is not structurally complex, but faults do intersect the Sherwood formation regionally. Consequently, water injection could potentially cause fault reactivation, and hence seismic activity, via one of the following mechanisms:

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

EM-1 was drilled in 2007 and encountered 1,370ft of Sherwood sandstone at a depth of 2763ft TVDss (Figure 4-2); a new dedicated water injection well (hereafter designated EM-A) would be drilled close to EM-1, in a downdip location. For the purposes of the current study, it is reasonable to expect that EM-A would encounter the Sherwood formation with similar properties to those observed in EM-1, and that the top of the formation would be no shallower.

The current study assesses:

1. the risk of injecting up to 8,500 bpd of water into EM-1 or EM-A if that well intersects a fault;
2. the wider risk associated with injecting water into the Sherwood Formation, and hence increasing the ambient reservoir pressure in the Ebberston Moor area.

The risk associated with direct water injection into a fault plane in EMS-1 is the subject of a separate study (Rockflow, 2014).

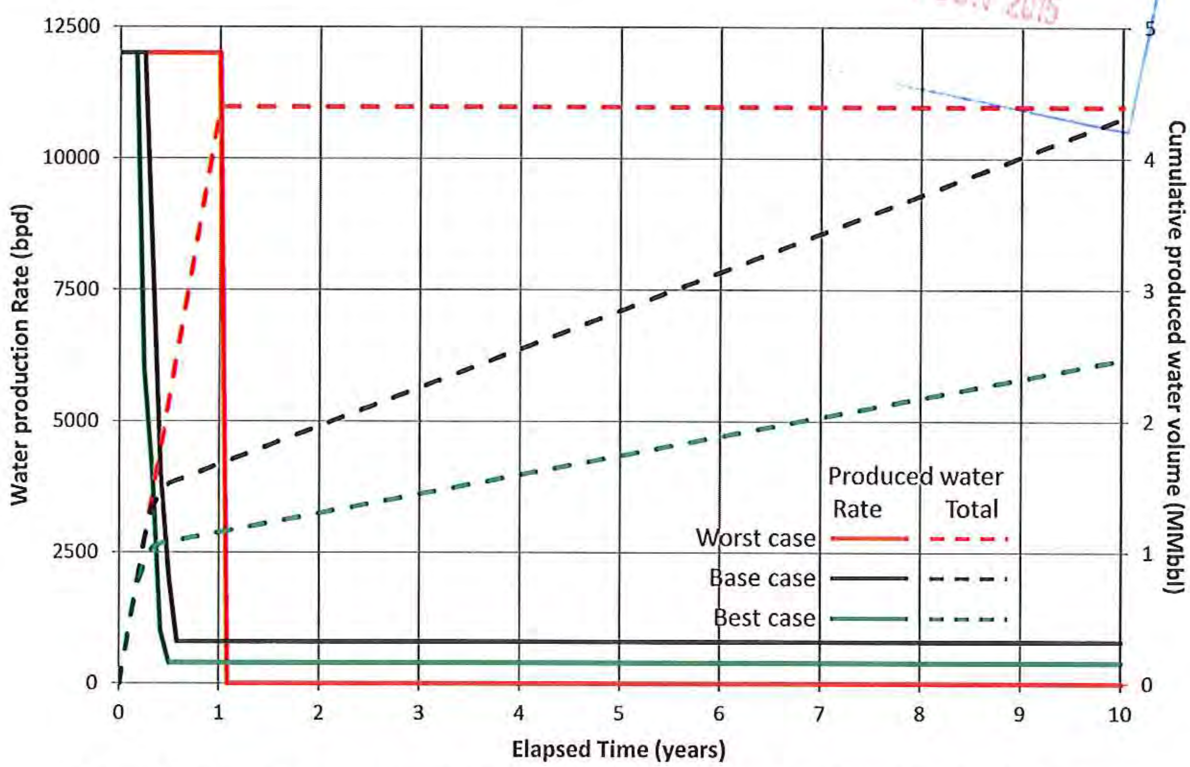

Figure 4-1 Ebberston Moor dewatering scheme: expected water production rates and volumes

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 Moor 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.

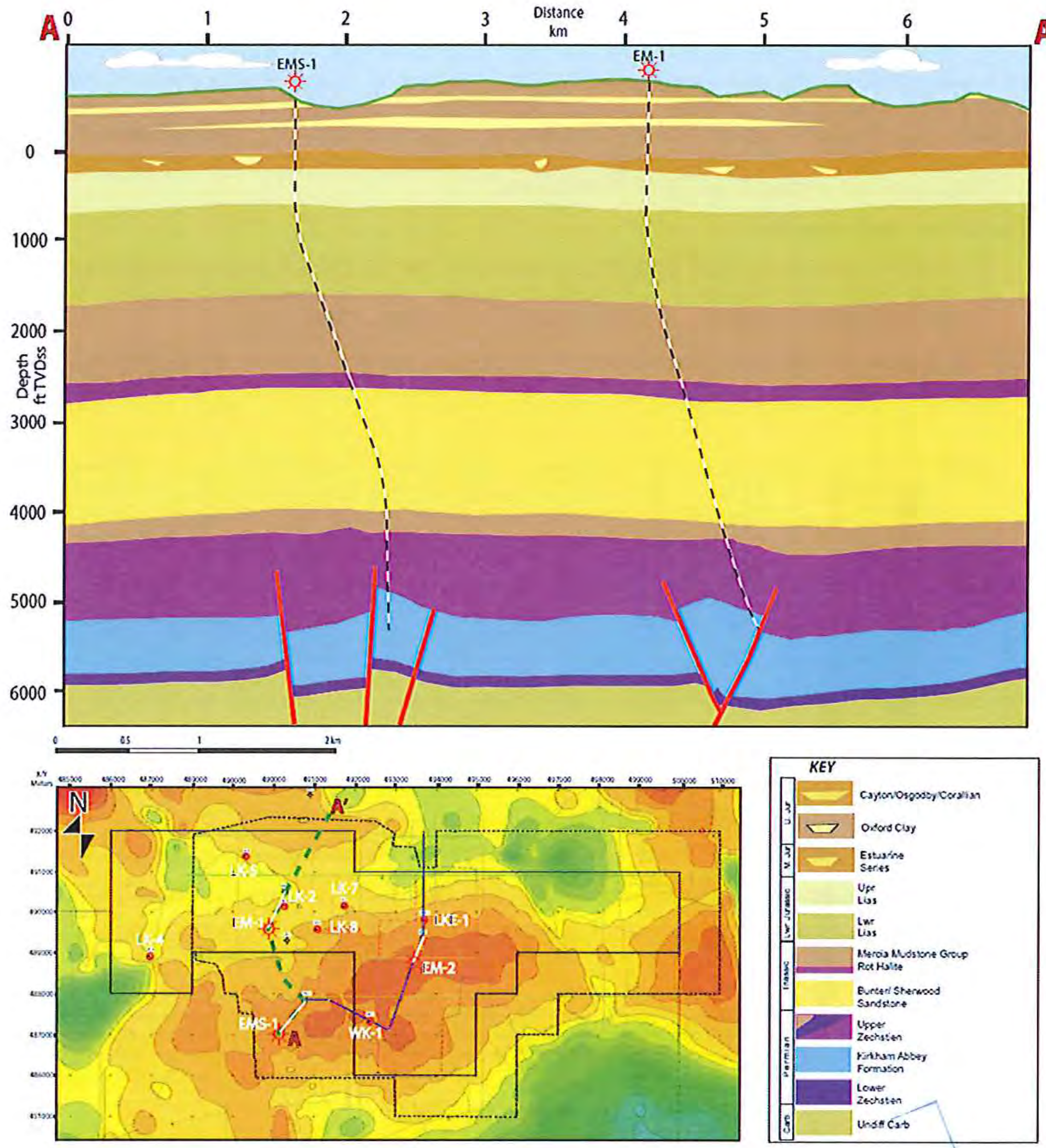

Figure 4-2 Ebberston Moor-1 geoseismic section

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 4-3; 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 4-4).

Ebberston Moor-1 is a deviated well that encounters the Sherwood Formation at a depth of 3873ft MD (2763ft TVDss or 3553ft TVDgl), and penetrates 1370ft MD (1104ft TVD) of formation before exiting into the underlying Zechstein (Figure 4-2). A standard suite of wireline log data were acquired across the Sherwood Formation (Figure 4-5), yielding an average porosity of 12.7%, with a net-to-gross of 75%, properties that are consistent with values obtained from other wells drilled in the area (Figure 4-6 and Table 4-1).

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 4-3).

The Ebberston Moor area is covered by 3D seismic, and is not structurally complex (Figure 4-7). The general structure is a gentle 4-way dip-closed anticline at the Sherwood level, with no seismically resolvable faults (i.e. with a throw greater than 30ft).

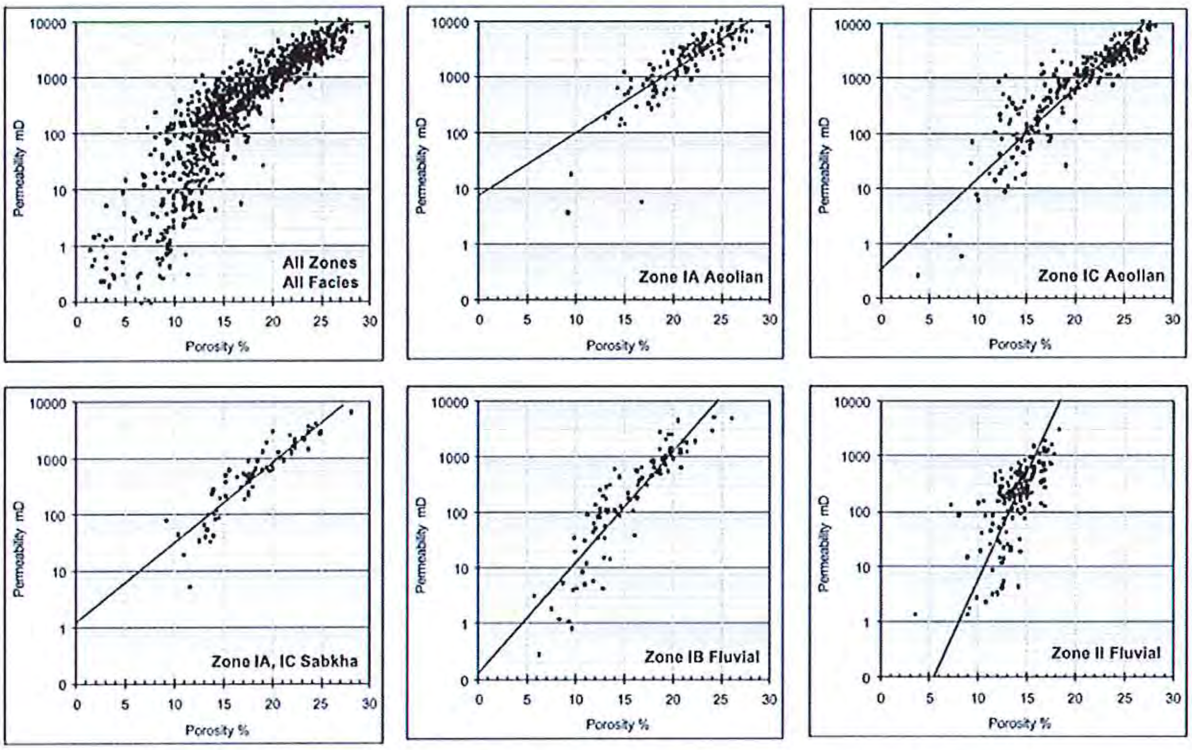

Figure 4-3 East Irish Sea poro-perm relationships for the Sherwood Fm. (Yaliz & McKim, 2003)

	Net To Gross	Porosity Range 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

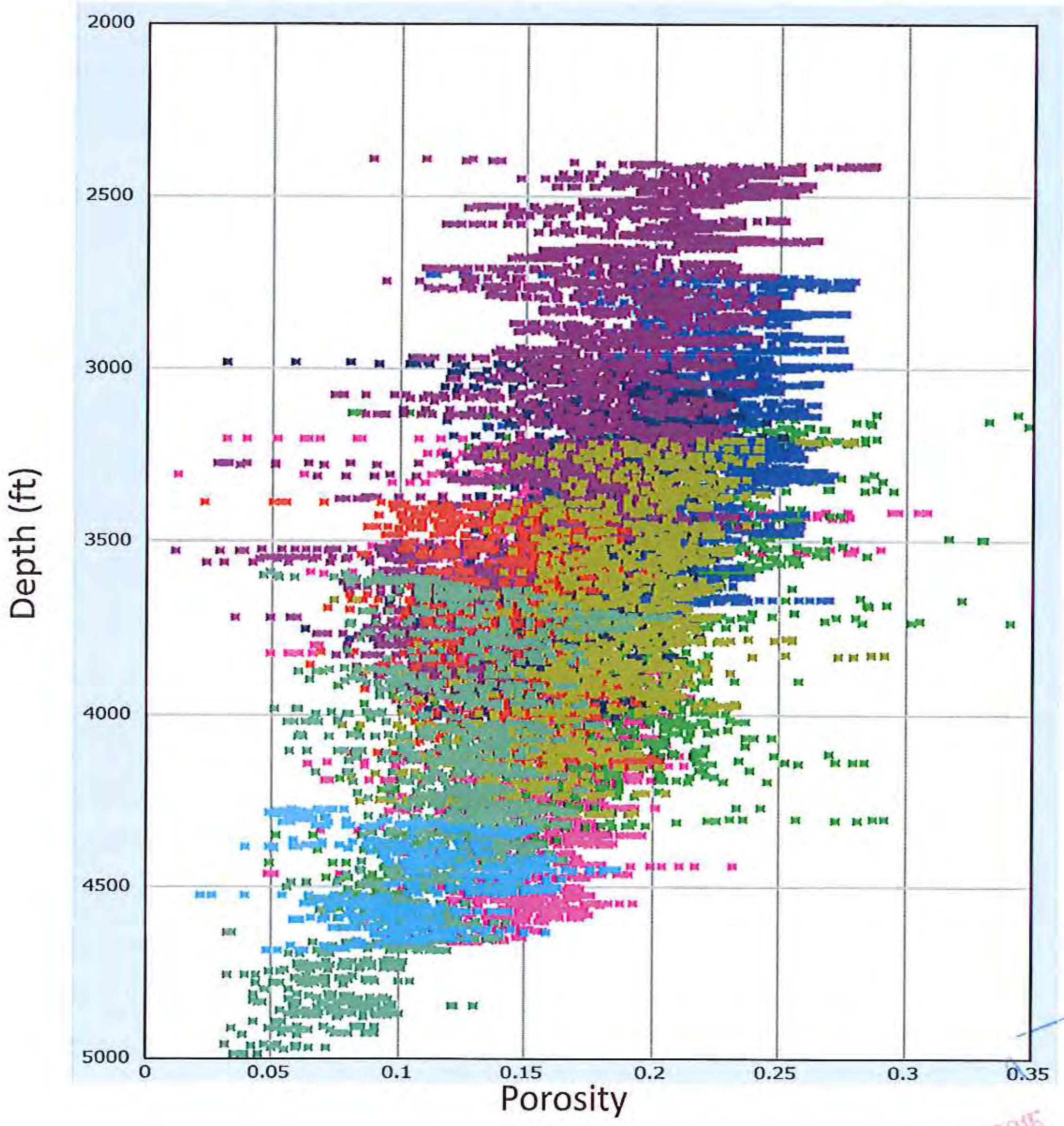

Figure 4-4 Porosity vs depth (Sherwood Formation, all Cleveland basin wells)

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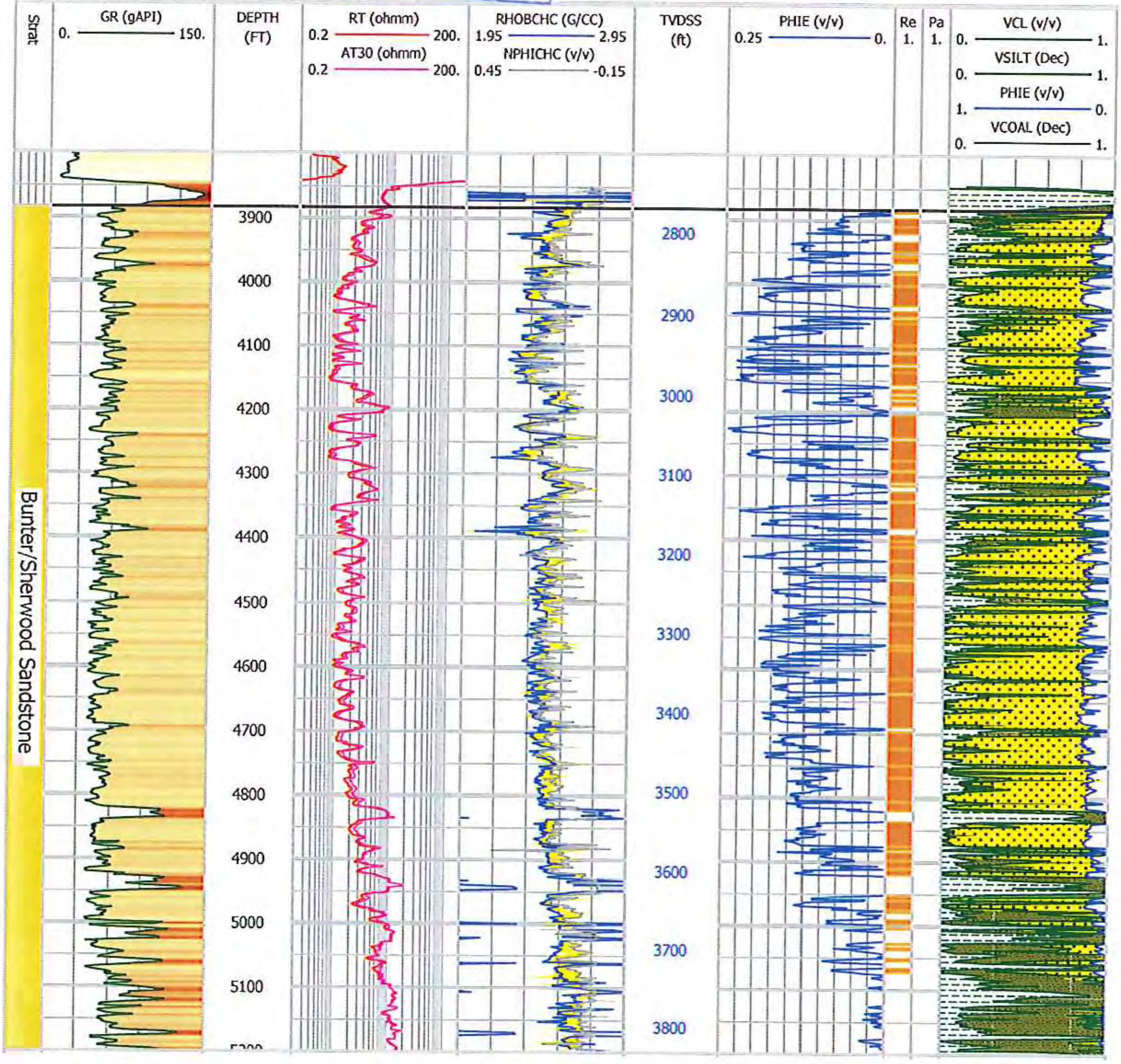

Figure 4-5 EM-1 CPI for the Sherwood Formation

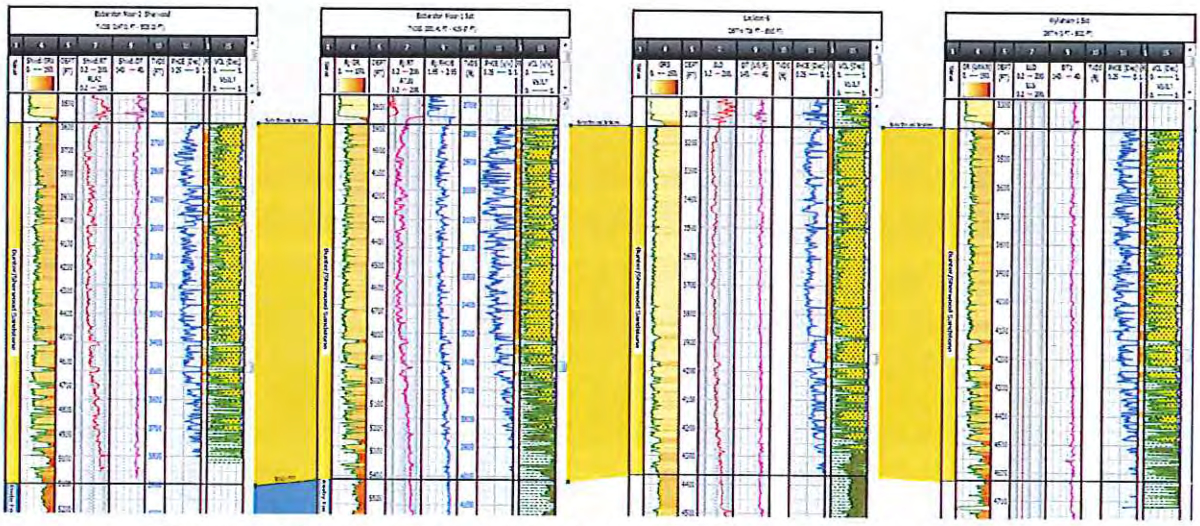

Figure 4-6 Correlation of the Sherwood Formation across the Ebberston Moor area

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 4-8). 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 4-9). 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 4-10. 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 4-10). 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 EM-1 well, the top of the Sherwood is at 3873ft MD (2763ft TVDss or 3553ft TVDgl), where the expected pore pressure is ~1255 psia based on extrapolation from measurements in EM-2. The maximum principal stress (the overburden) at this depth is approximately 3500 psia, while the minimum horizontal stress is no lower than 2700 psia.

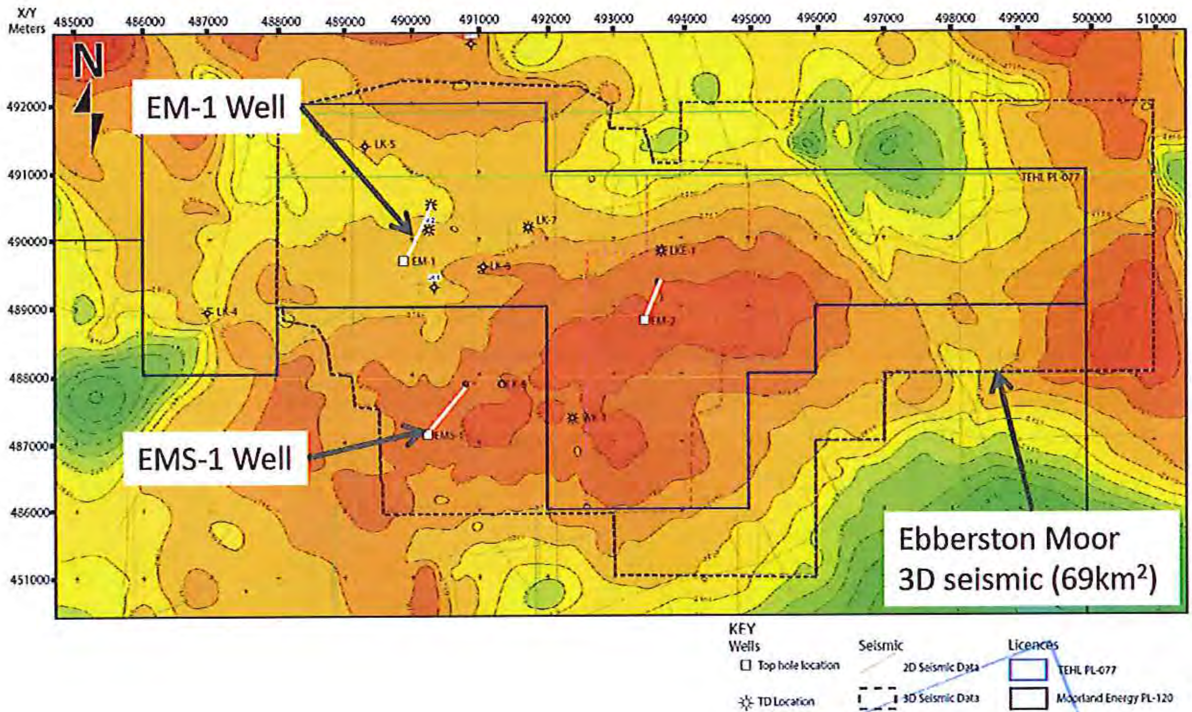

Figure 4-7 Top Sherwood Formation structural map over the Ebberston Moor structure

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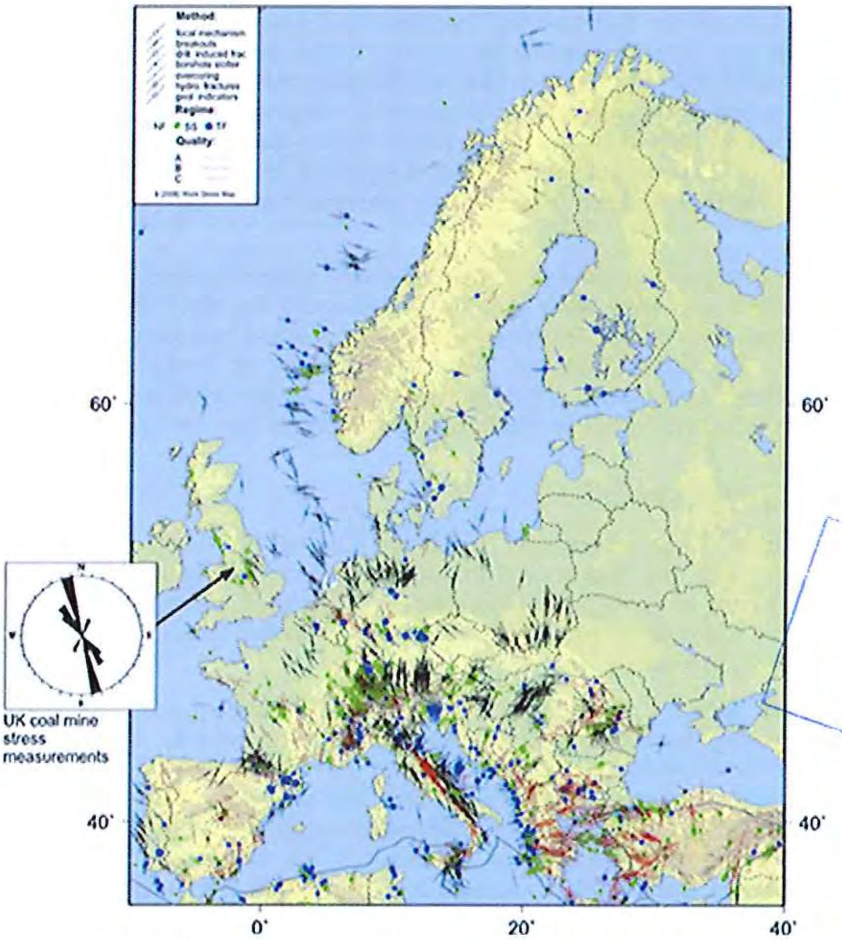

Figure 4-8 Measured horizontal stress map of western Europe

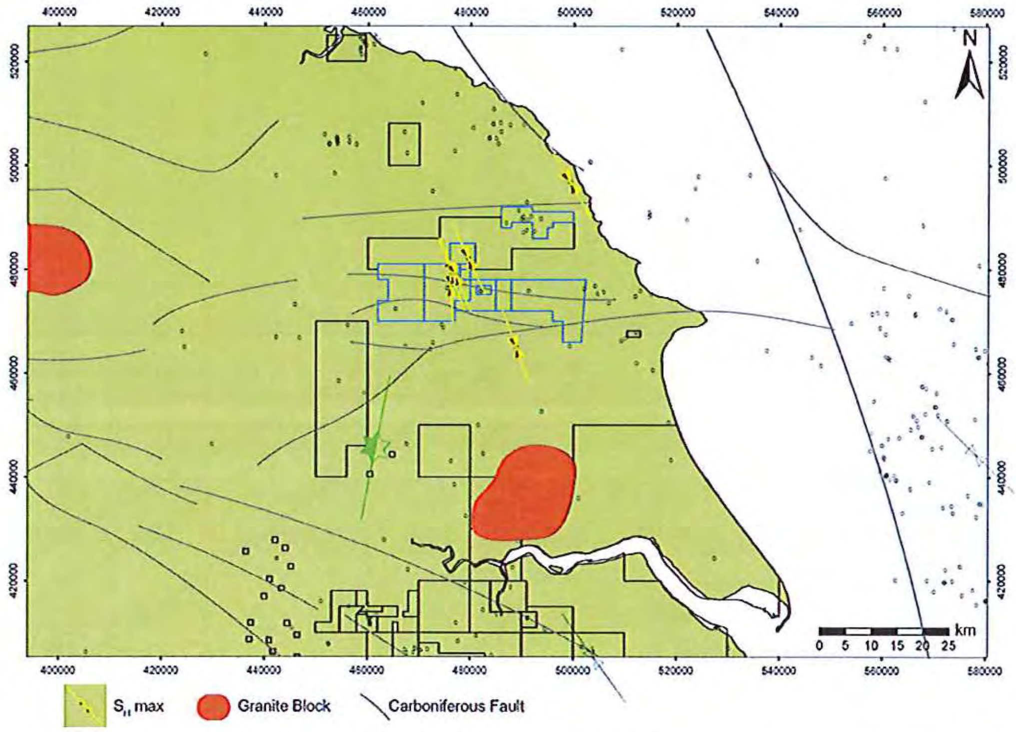

Figure 4-9 Measured horizontal stress map of the Cleveland Basin

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 2700 psia). Shear failure could occur at fluid pressures as low as 2250 psia, but would require 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.

A lowermost fracture point of 2250 psia provides a safe injection range, or trap integrity, of 1000 psia. If water is injected into EM-1 at a bottom-hole pressure no more than 1000 psi above the initial formation pressure, the risk of breaching the fracture gradient and potentially causing a seismic event will be minimal. For higher injection pressures, the risk of breaching the fracture gradient will increase. Conversely, as injection depth increases, e.g. by perforating the well further down into the Sherwood, the stress components increase, providing greater trap integrity.

4.3. Injectivity Assessment

Prosper models of injection schemes in EM-1 and a notional EM-A well were built to assess the impact of injecting water into the Sherwood Formation. The models calculate the expected flow-rate and borehole pressure for a given set of parameters (formation permeability, injection interval, fluid viscosity, wellbore dimensions, etc.). The results are presented below, and are based on a conservative set of parameter assumptions.

The bottom hole pressure (BHP) within the wellbore is dependent on a number of well-specific parameters, including the depth of the perforations, the tubing size, the tubing head pressure (THP) and the damage or impairment (skin) around the completion (Figure 4-11). The results show that frictional losses are a factor for higher flow rates, and may be a factor in the final decision of which option to implement. Recompletion of the EM-1 well to provide simultaneous gas production and water injection provides the best performance, although a new well completed with a 4.5" tubing is not significantly poorer. A bigger bore EM-A (i.e. completed with 9 ⅝" rather than 7" casing) will deliver superior performance, while completion with 3.5" tubing is not recommended.

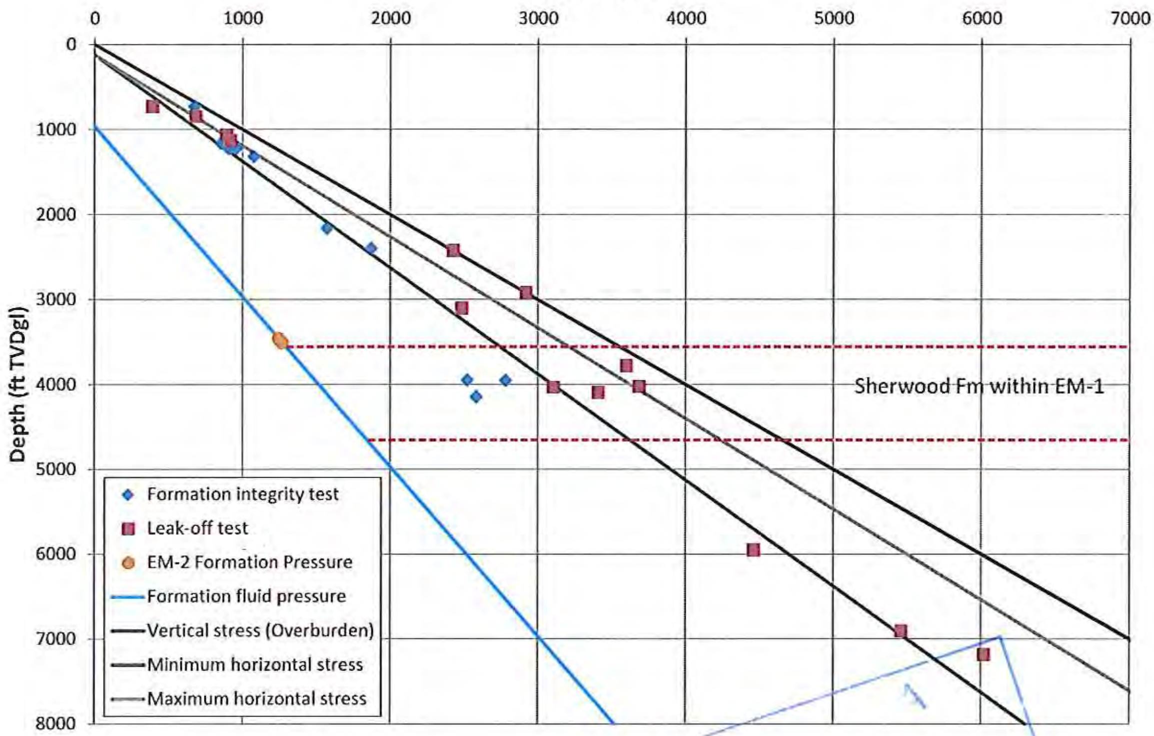

Figure 4-10 Stress data and relationships for the Cleveland Basin

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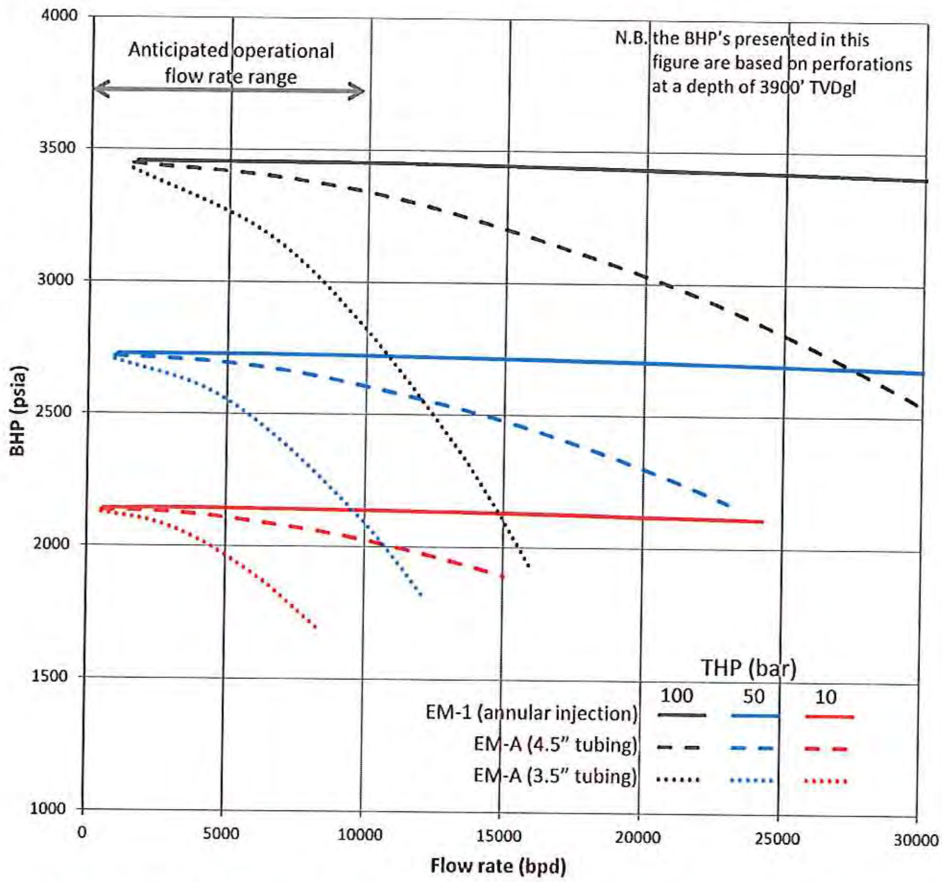

Figure 4-11 Relationship between BHP, THP, flow rate and completion design

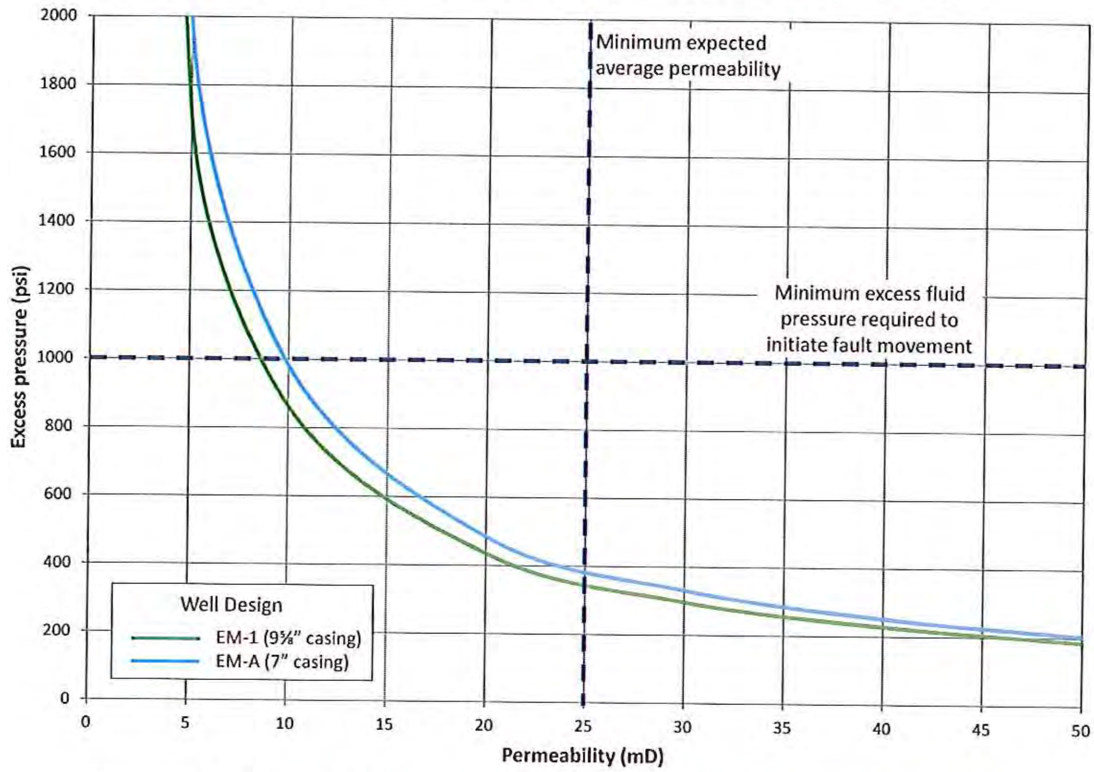

Figure 4-12 Excess fluid pressure required to achieve 8,500 bpd injection rate

However, for the purposes of the current study, the key parameter is the pressure delivered by the well to the rock in excess of the original formation pressure, the results of which are largely independent of well design. The only well design factor that is relevant is well bore size; the smaller circumference of a slimmer well (i.e. EM-A) means that less rock area is in contact with the well, and hence a higher pressure is required to deliver a comparable flow rate (Figure 4-12).

Once the frictional losses associated with well design and skin are removed, the relationship between delivery pressure and injection rate is much simpler. There is a linear relationship, controlled by permeability (Figure 4-13), between the rate achieved and the excess pressure above formation pressure that is delivered. As discussed in section 4.2, to safely remain below the lowest possible fracture gradient, the delivery pressure must not exceed the initial formation pressure by more than 1000 psi. Figure 4-12 and Figure 4-13 show that as long as the average permeability of the formation is greater than 10mD, up to 8,500 bpd of water can be injected into the Sherwood formation in Ebberston Moor without risk of breaching the fracture gradient.

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.

The injection pressure raises the formation pressure around the wellbore, and that excess pressure dissipates away from the well bore. Figure 4-14 and Figure 4-15 show how the fluid pressure drops with distance from the injection well for different permeabilities in a scenario where a flow rate of 8500 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 increases the effective wellbore diameter, and hence reduces the required injection pressure, which in turn reduces the effective radius.

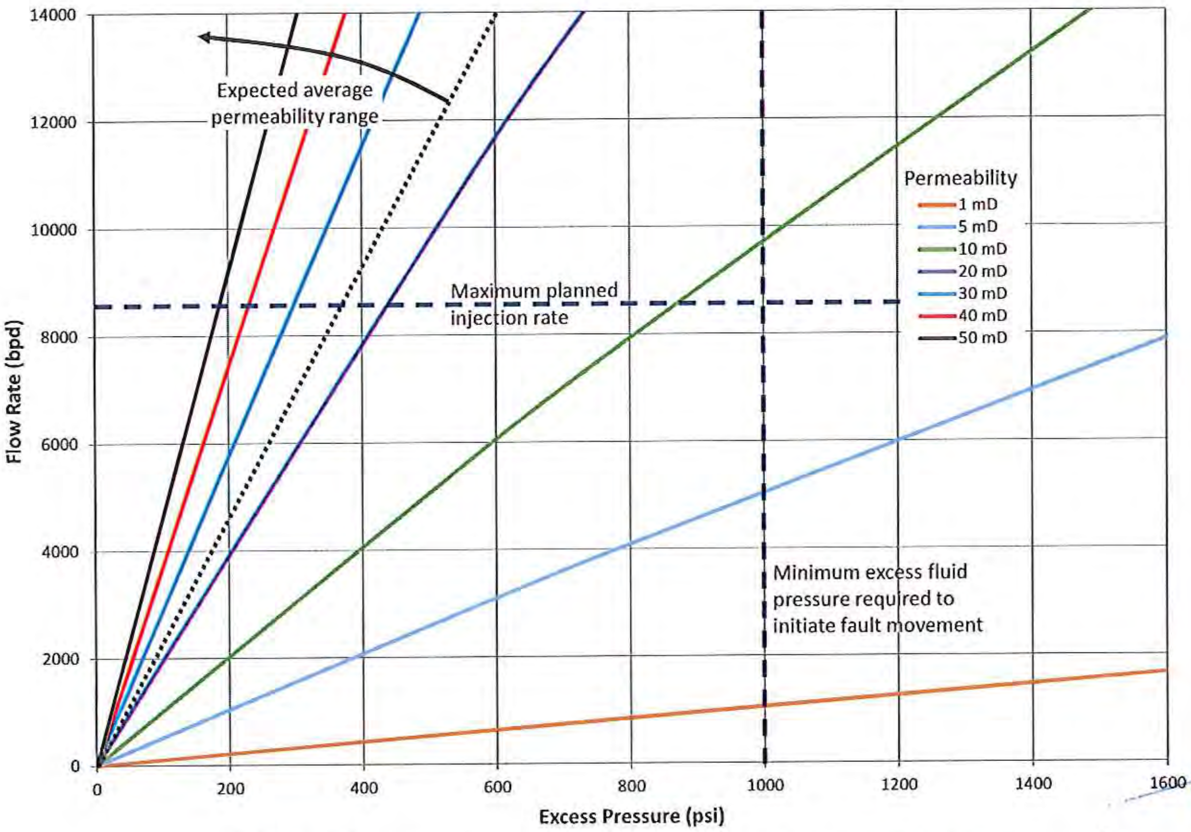

Figure 4-13 EM-1 Injectivity assessment: injection rate vs. excess fluid pressure

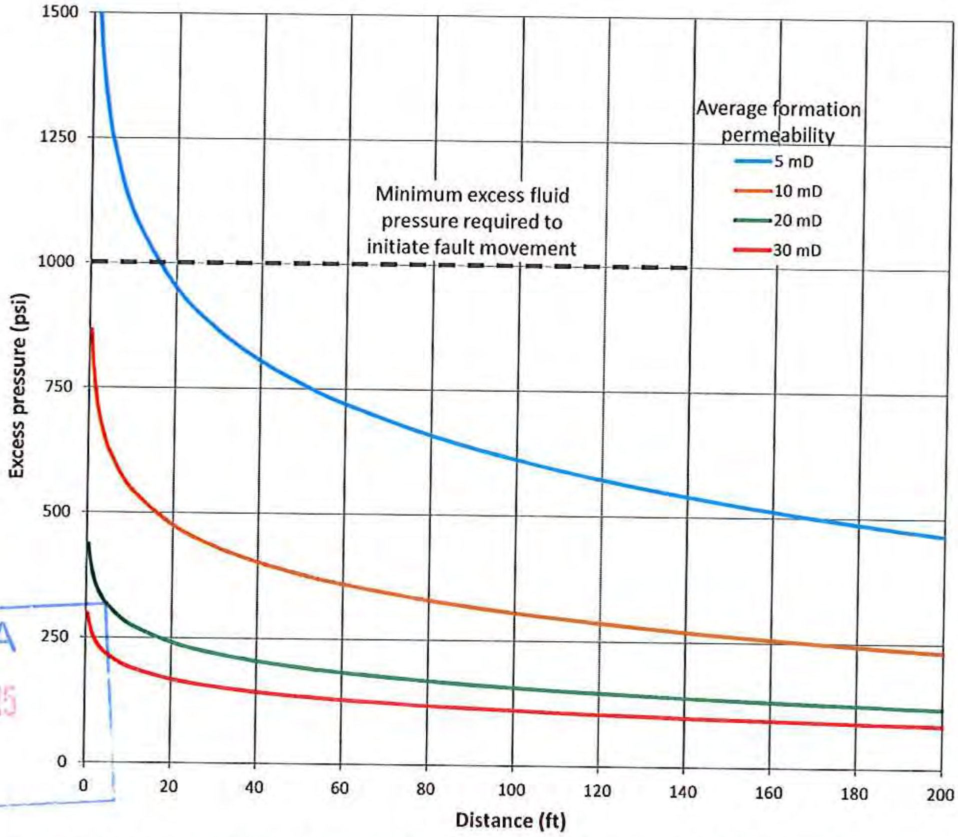

Figure 4-14 EM-1: Formation pressure dissipation for a constant 8,500 bpd injection rate

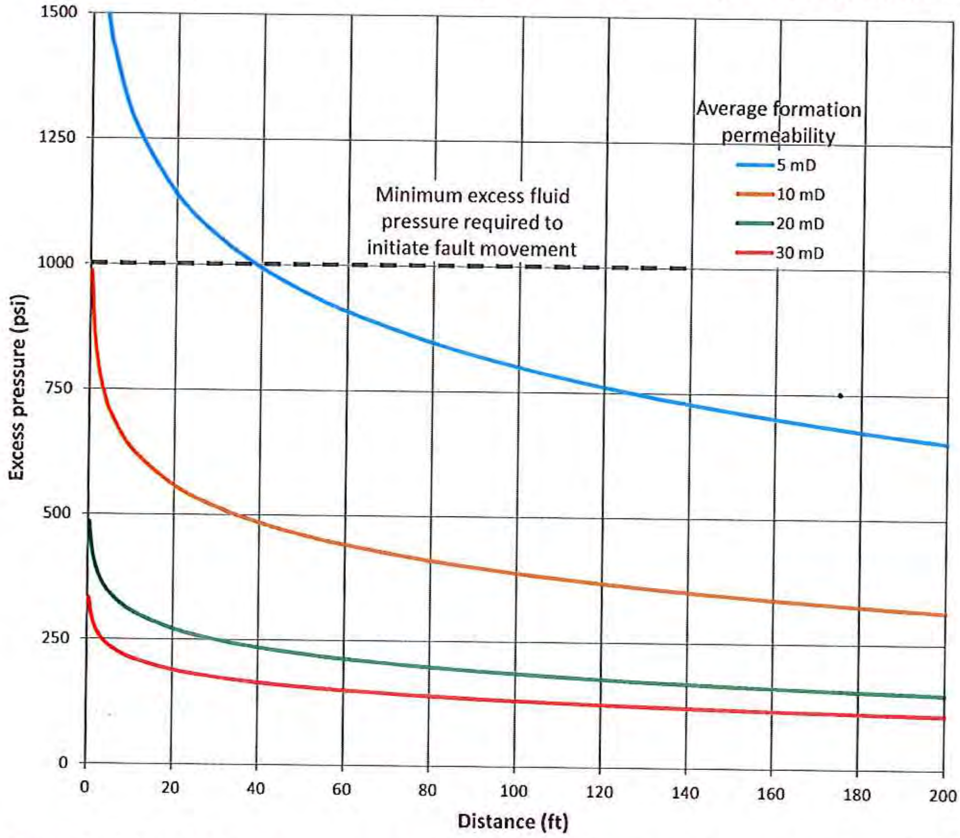

Figure 4-15 EM-A: Formation pressure dissipation for a constant 8,500 bpd injection rate

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 4-14, the formation pressure in rock with an average permeability of 5mD will fall below the minimum pressure at which fractures may occur no more than 16ft from the well, so that a maximum area of approximately 75m^2 around the wellbore will be subjected to formation pressures above the minimum fracture gradient.

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 8mD, then injection into EM-1 at a rate of 8500 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. The corresponding permeability for EM-A is 10mD.

In the assessment above, the scenarios assume that the well is perforated at the top of the Sherwood formation as encountered in in EM-1 (i.e. 3553 ft TVDgl). Deeper perforations would increase the trap integrity and reduce the risk of causing fault movement.

Additionally, the THP required to achieve an injection rate of 8500 bpd with an average permeability of 10mD (i.e. the threshold for potential fault movement) is 37 bar for EM-1 and 51 bar for EM-A. Consequently, such a scenario can be mitigated by ensuring that the relevant pump design is incapable of reaching such levels.

4.4. Pressure Compartments

Third Energy plans to produce gas from the Kirkham Abbey Formation within fields in the Ebberston Moor area via a dewatering scheme. Water will be produced in conjunction with the gas at a rate of up to 12,000 bpd (Figure 4-1), and Third Energy proposes to inject the produced water for disposal into the Sherwood formation via the EMS-1 well and either a recompleted EM-1 or a new EM-A well.

The proposed scheme will inject a significant volume of water into the Sherwood over the life of the field, which will raise the ambient reservoir pressure of the formation in the Ebberston Moor area hence increasing the risk of fault reactivation and seismic activity across a wider area.

The base case development scenario expects injection rates to fall as the KAF reservoir dewaters, facilitating gas production. Long-term water production rates of 800 bpd will yield a total of 4.3 MMbbl of water over 10 years for injection into the Sherwood formation (Figure 4-1).

A best case scenario (in terms of gas production) produces water at half of the base case rate, resulting in less than 2.5 MMbbl of water injected into the Sherwood; this scenario has not been considered for the current study.

The worst case scenario from a development viewpoint is one where the KAF does not dewater, which would mean that gas could not be produced at economic rates. In such a scenario, the scheme would be curtailed, and the field abandoned, after one year. A total of 4.4 MMbbl of water would be produced in that year, a volume that is coincidently very close to the base case development scenario.

However, while field abandonment after one year might represent the worst case scenario from an economic perspective, other downside cases must be considered for the current assessment. For example, dewatering may occur, enabling economic gas production, but the long-term water production rate may be higher than the base case rate of 800 bpd. Consequently, in order to assess the risk of prolonged injection into the Sherwood formation other long-term water production rates have been considered (Figure 4-16):

- 1600 bpd, equivalent to a rate that is double the base case;
- 4000 bpd, which is five times the base case rate, and a third of the maximum 12,000 bpd rate;
- 6000 bpd, which is 7½ times the base case rate, and half the maximum 12,000 bpd rate.

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, triggering rock failure and potentially fault movement.

The Ebberston Moor structure is not structurally complex (Figure 4-7), with no seismically resolvable faults (i.e. with a throw greater than 30ft) at the Sherwood level, and no mapped fault compartments. The Sherwood is laterally extensive (Figure 4-17), and unless the faults in the Sherwood completely offset the reservoir (i.e. with an offset in excess of 1000ft), there is no evidence that sand-on-sand faults in the formation 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.

The compressibility of formation water is a function of temperature and pressure, but is larger than 2.5×10^{-6} psi^{-1} for all conditions relevant to the current discussion. This minimum value means that one barrel of water will raise the pressure by 1 psi when injected into a pore volume of 400,000 bbl, and by 1000 psi when injected into a pore volume of 400 bbl. Higher compressibility will result in lower respective pressure increases.

When conservative Sherwood formation parameters for net-to-gross (75%) and average porosity (12%) are applied (Table 4-1), $1m^3$ of rock contains approximately ½ barrel of connected pore volume. Various scenarios can then be considered. For example, the area around Ebberston Moor covered by 3D seismic is approximately $69km^2$ (Figure 4-7), and no significant faults have been mapped within that area. Consequently, the aquifer within the 3D seismic area is probably not compartmentalised. If the Sherwood formation is at least 1000' thick everywhere (Figure 4-2), then the connected pore volume is likely to be in excess of 12 billion barrels, and injection of 1 million barrels will raise the formation pressure by less than 35 psi.

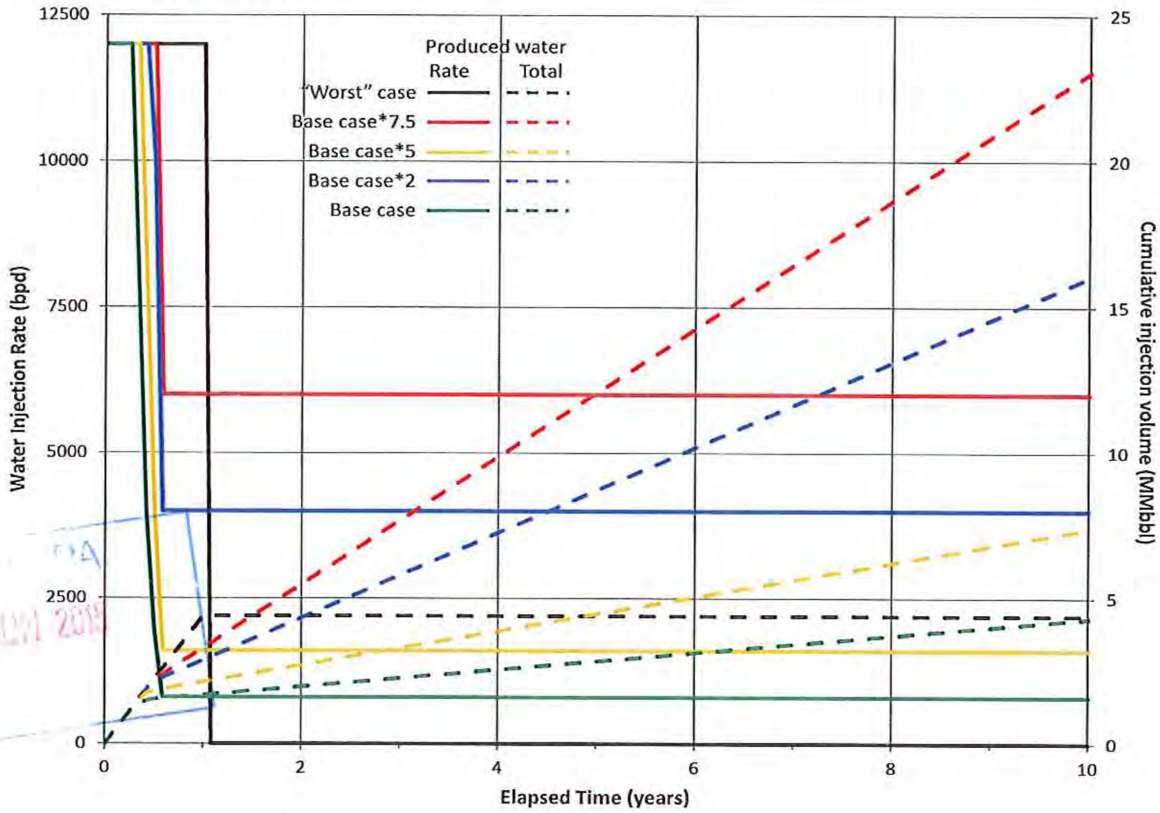

Figure 4-16 Injection scenarios considered

Table 4-2 details the maximum pressure rise after ten years that can be expected for different injection volumes across a number of scenarios. Various areas are considered based on:

- Ebberston Moor 3D seismic coverage (69 km^2; Figure 4-7);
- the distance (6.5 km) to nearest major fault in Vale of Pickering (130 km^2; Figure 4-17);
- the mapped onshore extent of the Sherwood formation that is not crossed by significant faults and lies below a depth of ~3000ft TVDgl (300 km^2; Figure 4-17);
- the regional aquifer size as mapped by Third Energy (3800 km^2).

The other variables considered include:

- effective thickness, or the portion of the reservoir that might be connected to the injectors:
  - 1000ft: a conservative base case formation thickness (Figure 4-2 and Figure 4-6);
  - 500ft: a reasonable downside scenario where the lower part of the formation is effectively disconnected from the upper sands by shale (Figure 4-5);
  - 250ft: an extreme downside, where water is restricted to the sands that connect directly to the well perforations;
- regional Sherwood properties (represented by net pore fraction):
  - 9% (i.e. 75% net-to-gross * 12% porosity) represents a very conservative base case;
  - 5% (50% * 10%) represents an extreme worst case;
- cumulative injection volume after ten years:
  - **4.4 MMbbl**: the expected base case, which is coincidentally similar to the worst case development scenario where water is injected at the maximum 12,000 bpd for a year;
  - **7.4 MMbbl**: equivalent to water production at a rate that is double the base case;
  - **16.0 MMbbl**: equivalent to water production at a rate that is five times the base case rate, and a third of the maximum 12,000 bpd rate;
  - **23.1 MMbbl**: equivalent to water production at a rate that is 7½ times the base case rate, and half the maximum 12,000 bpd rate.

In all cases, the minimum compressibility of 2.5×10^{-6} psi^{-1} has been applied, so the calculated pressure increase represents a maximum value.

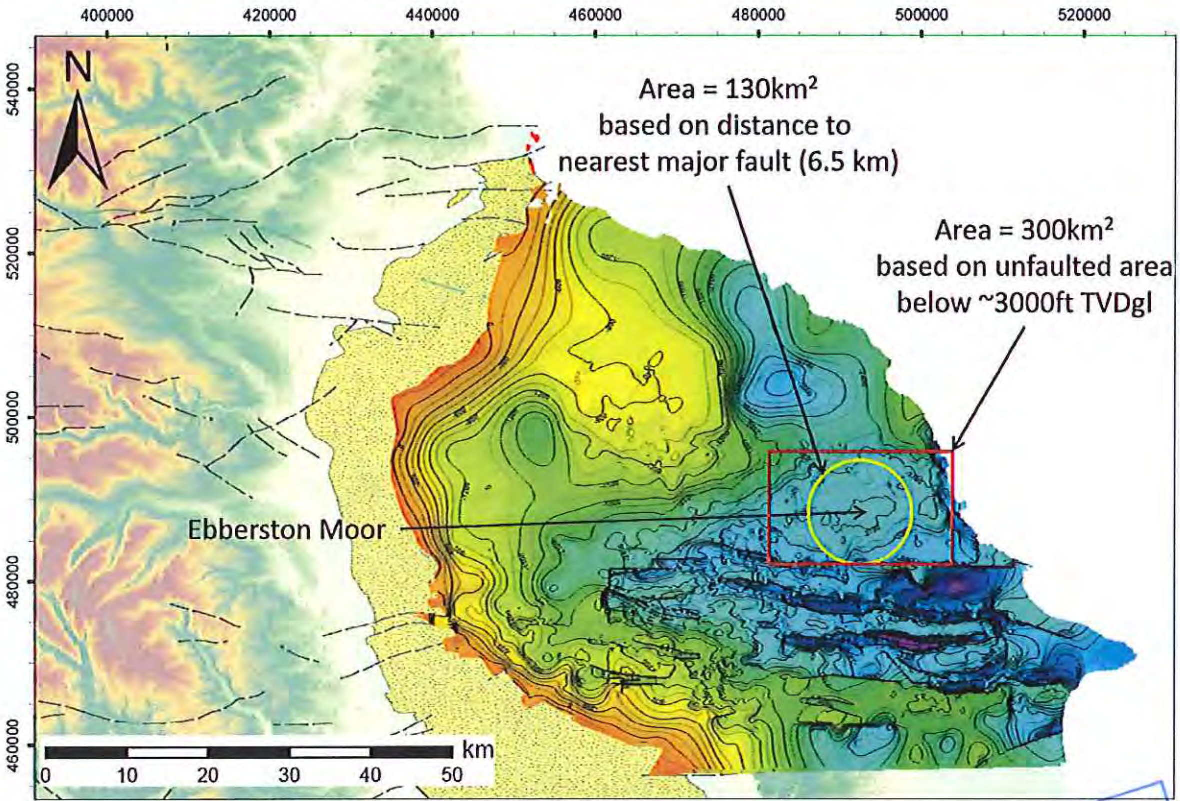

Figure 4-17 Top Sherwood subcrop map for North Yorkshire

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Effective Sherwood thickness	Net pore fraction *	Volume injected in 10 years (MMbbl)	Maximum pressure increase (psi) for an area based on: 3D seismic coverage	Distance to nearest mapped fault	Unfaulted area deeper than 3000ft TVDgl	Regional Sherwood aquifer area mapped by Third Energy
1000 ft	9%	4.4 (Base case or 1 year @ 12,000bpd)	147	78	34	3
	5%		265	141	61	5
500 ft	9%		294	156	68	5
	5%		530	281	122	10
250 ft	9%		589	312	135	11
	5%		1060	562	244	19
1000 ft	9%	7.4 (2* base case)	248	132	57	5
	5%		447	237	103	8
500 ft	9%		497	264	114	9
	5%		894	474	206	16
250 ft	9%		993	527	228	18
	5%		1788	949	411	32
1000 ft	9%	16.0 (5* base case, long-term injection rate = 4,000bpd)	539	286	124	10
	5%		970	515	223	18
500 ft	9%		1078	572	248	20
	5%		1940	1030	446	35
250 ft	9%		2156	1144	496	39
	5%		3880	2059	892	70
1000 ft	9%	23.1 (7.5* base case, long-term injection rate = 6,000bpd)	775	411	178	14
	5%		1395	740	321	25
500 ft	9%		1550	822	356	28
	5%		2789	1480	642	51
250 ft	9%		3099	1645	713	56
	5%		5578	2961	1283	101

* Net pore fraction is equivalent to net-to-gross multiplied by porosity

Key	Monitor	Very Risky
Safe	Unsafe	Dangerous

Table 4-2 Expected formation pressure increase for a range of scenarios

Within the area covered by 3D seismic, the Sherwood formation has a minimum depth of 2600ft TVDss (3300ft TVDgl). Based on the discussion in section 4.2, the formation pressure at that depth would be 1165 psia, while the minimum and maximum principal stress components would be 2540 psia and 3300 psia respectively. This means that formation pressure would have to rise by at least 1350 psi to cause hydraulic fracturing, and the minimum trap integrity is at least 900 psi.

Table 4-2 is categorised in line with these values and colour-coded accordingly:

- Safe: 0-450 psi. The pressure increase after 10 years of injection in such conditions will be less than half the minimum trap integrity.
- Monitor: 450-900 psi. The pressure increase will be less than the minimum trap integrity, but the pressure should be measured more regularly to ensure that it does not rise unexpectedly.
- Unsafe: 900-1350 psi. The formation pressure will be above the minimum trap integrity, and hence fracturing due to shear failure could occur; however it remains below the hydraulic failure pressure.
- Very risky: 1350-1800 psi. The formation pressure will be above the minimum hydraulic failure pressure, and has significant potential to cause fault movement.
- Dangerous: >1800 psi. The formation pressure will be higher than the maximum horizontal stress and is very likely to cause seismic activity.

The results show that the base case development scheme will inject a volume of water that is extremely unlikely to raise the regional formation pressure in the Sherwood formation to levels that might trigger a seismic event. The risk of an event increases as the injected volume rises, but the size of the connected reservoir is a key factor in determining whether the pressure rises to levels that will be of concern.

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.

Consequently, it is extremely unlikely that the proposed injection scheme will increase the fluid pressure within a reservoir compartment to a level sufficient to cause rock failure.

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.

5. Risk Assessment

The arguments presented in Section 4 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 pump 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 a pump 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. The probability of this occurring in contravention of specified design 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 4-3 and Figure 4-4, 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 trap integrity evaluation has a large error range (see section 4.2). The discussion above was based on a conservative assessment, but there is probably a 1 in 10 chance that the trap integrity in the Sherwood Formation near EM-1 is less than 1,450 psi. That probability falls with pressure, such that there is thought to be a 1 in 50 chance that the trap integrity is less than 1,200 psi, and a 1 in 200 chance that it is less than 1,000 psi.
- The Sherwood Formation is thought to be hydraulically connected over large distances, as demonstrated in the East Irish Sea, with sand-on-sand faults allowing fluid transmissibility. However, there remains a possibility that there are undetected faults around Ebberston Moor that are completely sealing, forming an effective compartment of restricted volume. As such the probability of connected aquifer covering an area smaller than the 3D seismic area is less than 1 in 500.
- There is probably a 1 in 200 chance that that the effective reservoir thickness is less than 250ft 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.
- Finally, there is a possibility that operational controls fail, and that an excessive volume of water is injected into the Sherwood formation. The probability that the cumulative injected volume will exceed the mandated limit is approximately 1 in 200.

None of these elements is sufficient in isolation to cause hydrofracturing and a seismic event. For example, if the permeability is less than 10mD (the level at which a magnitude 0.0 earthquake might occur), the planned pump would still deliver a THP of 20-30 bara, which would result in reduced injection rates rather than rock failure. However, if that pump 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, with probabilities of 1 in 500 and 1 in 1000, can cause a seismic event; the combined probability is 1 in 500,000.

Alternatively, the local trap integrity could be locally reduced to less than 1000 psi, and the pump's designed operating envelope might reach this pressure. However, an average permeability below 10mD or a higher injection rate would still be required to cause the rock fracture; the combined probability is in the order of 1 in 100,000.

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 50,000 to 1 in 20,000,000. Hence, the possibility of the proposed injection scheme in Ebberston Moor causing a seismic event larger than 0.0 in magnitude is assessed as less than 1 in 50,000.

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 5-1). 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 Ebberston Moor can be estimated. Table 5-1 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.

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.

Earthquake magnitude	Approximate area of fault movement	Probability of occurrence due to water injection in Ebberston Moor	Consequence
>0.0	$4m^2$	<1 in 50,000	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 2,000,000	Earthquake may be felt at the surface by individuals
>4.0	$5,000,000m^2$	<1 in 20,000,000	Threshold at which minor structural damage may occur

Table 5-1 Seismic event risk: probability and consequence

6. Conclusions and Recommendations

Third Energy plans to develop the Ebberston Moor, Ebberston South and Wykeham gas fields by producing gas from the Kirkham Abbey Formation (KAF) via a dewatering scheme that will produce water at a rate of up to 12,000 bpd. Third Energy proposes to inject the produced water for disposal via two wells into the Sherwood Formation in a scheme that is not designed to induce hydrofracturing of the rock.

The Ebberston Moor field area is not structurally complex, but faults do intersect the Sherwood formation regionally. Consequently, water injection could cause fault reactivation, and hence seismic activity, via one of the following mechanisms:

- direct injection into a fault plane;
- an increase in reservoir fluid pressure that breaches the fracture gradient.

The Sherwood sandstone has sufficient porosity and permeability to accept large volumes of injected water, and the injection pressures required to achieve the planned injection rates are relatively low.

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 10mD, water can be injected at pressures well below the fracture gradient for the full range of anticipated injection rates. For permeabilities below 10mD, lower injection rates will be achieved unless the injection pressure is raised to levels that may cause seismic activity.

The proposed scheme will inject a significant volume of water into the Sherwood over the life of the field, which will raise the ambient reservoir pressure of the formation in the Ebberston Moor area. The magnitude of the pressure increase is a function of the volume of reservoir connected to the injection wells, and although faults have been mapped around Ebberston Moor, they are not expected to compartmentalise the reservoir. Consequently, the base case development scheme will inject a volume of water that is extremely unlikely to raise the regional formation pressure in the Sherwood formation to levels that might trigger a seismic event.

In conclusion, the proposed injection scheme should incorporate a maximum pump design that ensures that the excess pressure applied to the rock around the well is lower than the minimum rock failure pressure. 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 50,000.

The risk can be further minimised by incorporating the following recommendations into the development plan:

- A big-bore well requires a lower pressure head to deliver a given flow rate, and hence recompletion of EM-1 will provide a larger safety margin than the proposed EM-A well.
- If a new EM-A injection well is drilled:
    - the trajectory should be designed to penetrate the Sherwood at a depth no shallower than observed in EM-1 (i.e. 2763ft TVDss or 3553ft TVDgl).
    - a big-bore design should be considered to minimise the required injection pressure.
- The highest fluid pressure exerted on the rock is immediately adjacent to the perforations, as the excess pressure dissipates with distance (Figure 4-14), both laterally and vertically. As trap integrity increases with depth, the top perforation should be at least 150ft below the top of the Sherwood Formation.
- Only a short perforation interval is required to inject volumes at the required rates; the results presented above are based on a 70 ft perforation interval. However, additional perforations would increase the volume of reservoir directly connected to the well. Hence, additional perforations (a longer perforation interval, or multiple intervals) are recommended.
- Monitor pressures in the injection wells and across the field at regular intervals to track formation pressures, particularly during the initial weeks of injection. The monitoring program should provide data that can guide future injection strategy decisions.
- Include extra specification safeguards to ensure that the injection pump configuration is unable to raise the BHP above the minimum rock failure pressure.

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