Evidence

Reinjection of fluids to deep geological formations

Report – SC150027/R

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Professor Doug Wilson
Director, Research, Analysis and Evaluation

Executive summary

This report aims to provide the Environment Agency with a greater understanding of the produced water reinjection (PWRI) process, enabling informed and consistent decision-making when regulating onshore oil and gas reinjection activities.

The main part of the report provides generic guidance developed from the detailed information obtained from a literature review which is presented in the appendix.

In general, reinjection of produced water from conventional oil and gas activities in England is low risk in terms of unwanted geomechanical impacts. High profile issues associated with reinjection and induced seismicity, and potential impacts to environmental receptors are, in general, linked to other countries, such as the USA. This is a function of the industry extent and practices, including different regulatory frameworks, and geological and tectonic settings such that the cases are not directly comparable with circumstances in England. This is reflected in the fact that the UK's conventional industry is now over 100 years old with no known case studies of environmental impacts resulting from subsurface geomechanical issues.

However, development of unconventional oil and gas activities may lead to increased demand for reinjection and this has been considered in the main part of the report, with areas for further study highlighted.

There is currently no explicit industry guidance relating to the management and/or mitigation of geomechanical risks from reinjection activities for onshore conventional oil and gas operations. As a result there are no specific requirements for industry to collect or present data to support mitigation methods for such activities. However, many of the reservoir management approaches employed by operators are likely to inadvertently mitigate many of the potential risks.

Using the outputs of the literature review, the generic guidance presented in this report has been developed to aid the Environment Agency's decision-making and regulation of the English onshore oil and gas industry. The aim has been to develop guidance that remains proportionate and relevant to existing English onshore practices. The document is mindful of other approaches or methods that could be considered reasonable to minimise risks from reinjection activities and examines how future industry guidance could be informed to manage the potential risks of reinjection.

In summary the guidance presents:

- an overview of the conditions that may give rise to geomechanical impacts
- an overview of the general PWRI approaches employed in England and how such approaches may mitigate geomechanical impacts, mindful of the various conditions that may give rise to unwanted impacts
- an overview of how potential mitigation measures can be identified and used to inform the permitting of specific reinjection activities
- a review of the applicability of the guidance presented here to 2 other industrial activities – carbon capture and storage and geothermal energy
- a review of alternative reinjection management approaches that may offer environmental benefits

The appendix includes:

- an overview of the legislative and regulatory context in England

- a review of relevant technical literature focusing on conventional operations with a view to producing (i) a ‘user friendly’ overview and summary of the reinjection process and (ii) a technical description of the reinjection process
- a summary of the guidance and controls in other key countries, focusing on reinjection for conventional operations
- case studies of pertinent events where reinjection has led to seismic impacts in key countries, focusing on reinjection events for conventional activities and, where possible, in similar geological conditions
- a review of current reinjection activities for onshore England informed by industry liaison and a webinar
- a summary of future trends and demands for reinjection activities

Contents

1 Introduction

The aim of this report is to provide the Environment Agency with an improved understanding of the produced water reinjection (PWRI) process so as to enable informed and consistent decision-making when regulating onshore oil and gas reinjection activities.

PWRI is a recognised strategy within the oil and gas industry and can be beneficial to production activities and a cost-effective means for managing waste water. An appropriately managed PWRI strategy can be considered to be an environmentally attractive disposal technique, while aiding optimisation of the production of oil mainly though reservoir pressure maintenance.

As exploited reservoirs mature, the quantity of water produced increases. Produced water is the largest single waste fluid stream in exploration and production operations (OGP 2000). Where reinjection is required to support production, the correct design and implementation of a PWRI strategy (or waste management strategy if reinjection is not required) is critical to the effective production of oil and gas and a key focus of oil and gas operators. Where PWRI strategies are not designed or implemented properly, a range of issues can arise (for example, injectivity and containment problems) negatively affecting production and potentially creating safety and environmental issues, which can significantly undermine the overall operation.

On behalf of the Environment Agency, Atkins recently investigated the establishment of best available techniques (BAT) for the treatment and disposal of fluids from oil and gas operations. The final report (Environment Agency, forthcoming) recommended that reinjection of produced water (to a producing formation) in conventional oil and gas is considered BAT provided:

- the produced water is required for operational purposes
- a groundwater activity permit is obtained
- well integrity is controlled and monitored effectively

There are a number of technical considerations when developing a PWRI project, which are discussed in the following sections of this report. In England, these considerations have remained almost entirely focused on managing the operational aspects of reinjection. This is because geomechanical issues, including induced seismicity, have not generally been recorded or considered – by industry and regulators alike – an issue that warranted active management or regulation.

In developing this report, particular attention has been given to these various considerations and what mitigation and management approaches are used (or could be used) to minimise the risks of impacts to groundwater and other environmental receptors.

1.1 About this report

The main part of this report provides generic guidance on:

- what information is, and could be, collected by operators in England
- how this information can be used to assess whether risks from geomechanical impacts are being managed effectively

This guidance was developed from the more detailed information presented in Appendix A which was obtained from an extensive literature review.

In addition to the literature review, the guidance presented in this report was developed bearing in mind:

- important industry feedback given during a webinar held by UK Onshore Oil and Gas (UKOOG) and led by Atkins on 24 February 2016
- review comments from IGas plc on the most important aspects of applying a PWRI strategy in England

1.1.1 Report structure

A summary of the report structure is presented below.

- **Background.** Section 2 presents an introduction to the project including key definitions and a description of the project's objectives and scope.
- **Summary of information from the literature review**: Section 3 provides a summary of the information from the literature review presented in Appendix A relating to PWRI and potential links to geomechanical aspects such as induced seismicity.
- **Generic guidance.** Based on the detailed information from the literature review, Section 4 outlines the most important considerations for the Environment Agency when regulating reinjection activities.
- **Areas for further research.** Section 5 provides an overview of the data gaps and uncertainties identified from this work and highlights those areas that may benefit from further research.
- **Detailed information from the literature review**. Appendix A presents high level background on the onshore oil and gas industry in England, a description of the reinjection process and 8 short case studies from the UK, France and the USA.

2 Background

Reinjection of produced water from conventional oil and gas production is one of a number of known causes of induced seismicity. It has been the cause of notable earth tremors in some oil producing countries, although none have been recorded in England. There are concerns that, if such incidents were to occur in England, this could lead to adverse impacts on groundwater resources. Examples of such impacts are:

- inadvertently fracturing strata that affords containment for the reinjected fluids, creating pathways for contaminants to reach groundwater
- reactivation of faults leading to seismic activity
- causing damage to the integrity of injection wells
- causing adverse impacts on other infrastructure such as underground storage tanks and abstraction wells

The regulation of geomechanical aspects, specifically induced seismicity in England, is the responsibility directly or indirectly of a number of bodies including:

- Health and Safety Executive (HSE) – has regulatory powers where reinjection activities or well design and construction could lead to unacceptable health and safety risks
- Environment Agency – regulates the permitting of groundwater activities under the Environmental Permitting Regulations 2010
- Oil and Gas Authority (OGA)
- Department of Business Energy and Industrial Strategy (BEIS)

BEIS's main focus, in the context of reinjection, is on shale gas activities (rather than conventional activities). It takes the lead on approving fracture plans which include mitigation plans for induced seismicity from fracking activities. Its involvement in reinjection activities is limited to fracking activities only.

There are a number of statutory bodies involved in the regulation of aspects of the conventional oil and gas activities in England, with formal regulatory control by the Environment Agency on conventional reinjection activities, which requires a permit for a groundwater activity, and by OGA for completion of a water injection well.

In addition to the reinjection of produced water, induced seismic events have been known to occur as a result of other man-made processes including but not limited to reservoir impoundment and mining activities. These sources of induced seismicity are not the focus of the study but, where applicable, examples of such cases are drawn on to provide regulators with context in relation to other major industrial activities.

2.1 Definitions used in this report

Definitions for the various onshore oil and gas industries are provided in Table 2.1. In some cases, definitions within the industry vary but for the purpose of this report, the following are used.

Table 2.1 Key definitions used in this report

Term	Definition
Conventional oil and gas	Extraction associated with reservoirs in which buoyant forces keep hydrocarbons in place below a sealing caprock.
Continuous pressure monitoring	Method of monitoring pressure to enable comparison with predicted constant pressure in conventional reservoirs. The activity aims to determine the potential presence of loss of injectivity (damage to reservoir or infrastructure) or unwanted fracture propagation (loss of containment).
Depletion	The removal of hydrocarbons from a reservoir.
Drilling fluids	Generally considered to be synonymous with drilling muds.
Enhanced oil recovery (EOR)	Refers to the implementation of various techniques for increasing the amount of crude oil that can be extracted from an oil field. Compare with **water flooding**.
Exploration	Generally considered to be all stages taking place prior to commercial development. Includes appraisal and prospecting.
Fall off testing	A testing process to determine reservoir pressure, fracture propagation pressure and closure pressure. It will also aim to determine development of formation transmissivity and to confirm the size of the flow unit into which injection takes place.
Flowback fluids	Fluids that are allowed to flow from an unconventional (that is, shale gas) well following well stimulation.
Injection	Refers to the addition of fluids that were not derived from the formation into which they are being injected (for example, injection of seawater as 'make-up' water into a conventional hydrocarbon reservoir from which oil or gas is being extracted). Compare with **reinjection**.
Injectivity	The injection rate divided by the difference between the injection pressure and the reservoir pressure. A measure of the ability of the well and injection interval to take up injected fluids.
Net rate of injection	The rate at which fluid is injected into the reservoir less the rate at which flowback fluids exit the reservoir.
Produced waters	Water that is naturally present within the geological formation which is brought to the surface during hydrocarbon extraction. Formation water (water naturally present within the rock) and connate water (water present within the rock at the time of deposition) are constituents of produced water.
Production	The phase of works in which oil and gas is extracted commercially.

Term	Definition
Proppant	A material, typically silica sand, injected as part of the hydraulic fracture operation for the purpose of propping the fractures open once they have been created.
Reinjection	Involves the return of fluids to the formation from which they were derived (for example, reinjection of produced water). Compare with **injection**.
Reservoir	The zone of a formation that hydrocarbons inhabit.
Reservoir impoundment	The filling of a reservoir behind a dam, significantly increasing the vertical overburden stress.
Stimulation fluids	Relevant to conventional and unconventional oil and gas production. Fluids (mostly water and containing small percentages of other chemicals and solids (for example, sand)) added to the well to improve production, through for example, EOR or hydraulic fracturing.
Stress perturbation	A change to the in situ stress field, in this case caused by injection of fluids.
Tight gas	See **Unconventional oil and gas**.
Unconventional oil and gas	Generally considered to be extraction associated with any resource where the properties of the reservoir differ from a conventional reservoir, for example, due to porosity, permeability or fluid trapping characteristics. Includes shale gas, shale oil, coal bed methane, coal seam gas, gas hydrates, oil shale, oil sands and tight gas sands.
Water flooding	Refers to the method in the oil industry where water is injected into the reservoir, usually to increase pressure and thereby stimulate production.
Well completion brines	Fluid with high salinity and low solids content that is used to enable the safe and efficient operation of the well and extend the life of a well by controlling issues such as corrosion and plugged reservoirs.

2.2 Scope and objectives

2.2.1 Objectives

The overarching objective of this research project was to provide recommendations on determining appropriate rates of reinjection of produced waters and other fluids associated with oil and gas activities in England such that potential risks to groundwater or other sensitive environmental receptors are minimised.

Given the site-specific considerations of the various sites in England, quantitative or prescriptive criteria for reinjection rates or pressures have not been developed. Instead the report focuses on:

- identifying the most important conditions that may lead to geomechanical impacts

- determining what existing international and domestic (that is, England) approaches and processes can be deployed to mitigate such geomechanical impacts and their potential risks to environmental receptors

The outputs are intended to enable regulators and operators alike to apply consistent decision-making both when assessing permits and more generally when managing potential risks from the reinjection process.

2.2.2 Scope of work

To achieve the project's objective, the following were prepared based on a review of a range of information sources (see Section 2.3):

- an overview of the legislative and regulatory context in England
- a review of relevant technical literature focusing on conventional operations with a view to producing (i) a 'user friendly' overview and summary of the reinjection process and (ii) a technical description of the reinjection process
- a summary of the guidance and controls in other key countries, focusing on reinjection for conventional operations
- case studies of pertinent events where reinjection has led to seismic impacts in key countries, focusing on reinjection events for conventional activities and, where possible, in similar geological conditions
- a review of current reinjection activities for onshore England informed by industry liaison and a webinar
- a summary of future trends and demands for reinjection activities

The information contained in these outputs is presented in Appendix A and was used to:

- develop generic guidance for establishing appropriate methods of mitigating the risks of unwanted geomechanical impacts resulting from reinjection activities
- consider its applicability to other industries such as carbon capture and storage and geothermal
- identify data gaps and areas for potential further research

The results of this work are presented in the main part of this report.

2.3 Information sources

The following types of sources were used to inform this study:

- UK legislation, regulations and guidance
- industry-accepted codes and standards – for example, American Petroleum Institute (API)
- industry reports
- key guidance documents in leading oil and gas producing countries (that is, the USA, Canada and the UK)
- peer-reviewed papers published in reputable journals or conference proceedings

- feedback from UK operators via a webinar held on 24 February 2016

A full list of references is presented at the end of this report.

3 Summary of information from the literature review

This remaining sections of this report are based on the information obtained from the literature review (see Appendix A) as well as input from industry on the application of PWRI strategies in England. This section provides a summary of this information.

3.1 Geomechanical impacts and potential risks to groundwater

Risks to groundwater or other environmental receptors from geomechanical impacts associated with induced seismicity from reinjection activities to deep formations may exist. However, this conclusion is based on a review of case studies that included:

- processes not relevant to conventional oil and gas reinjection (that is, high pressure, high volume hydraulic fracking)
- tectonic regimes and geological settings different to those in England

Little to no detail was available for the case studies on the level of good practice adopted for each case.

Importantly, there are also no known records of induced seismicity in England associated with conventional oil and gas reinjection activities that have resulted in contamination or damage to infrastructure. The apparent prevalence of induced seismic activity in oil producing countries such as the USA is also likely to be associated with the relative size of their industry compared with that in England (that is, the USA industry is significantly larger and more geographically widespread than in England[1]). There are also differences in geology, with a greater likelihood of natural overpressuring in the USA.

Table 3.1 presents a summary of the potential geotechnical impacts and the risk to groundwater. These potential impacts may be related to the conditions that could give rise to impacts (see Table 4.1), which may be mitigated using approaches as detailed in Table 4.2.

Table 3.1 Summary of potential geomechanical impacts and their risks to groundwater

Potential risk area	Cause	Comments
Damage to (or poor construction of) well casing providing a conduit between the reservoir and groundwater	Single event damage in operational or abandoned wells Cumulative build-up of	Damage to wells and in some cases well integrity are recorded in a number of cases, including the one known to have occurred in at Preese Hall in England (which caused deformation of the casing but not loss of well integrity). This is considered to represent the largest potential risk of creating direct pathways to sensitive environmental

[1] In 2014, an estimated 1,002,576 tonnes of onshore crude oil were produced in the UK (OGA website) compared with an estimated 35 million tonnes of crude oil from USA onshore oil fields (Energy Information and Administration, February 2016).

Potential risk area	Cause	Comments
	seismic events inducing fatigue in operational or abandoned wells	receptors, especially groundwater. However, there are very few instances globally where contamination has been linked to such outcomes (east Pennsylvania) (Davis et al. 2012). In England, high standards of well integrity are maintained with strict oversight provided by the Health and Safety Executive (HSE), as well as regular well integrity monitoring and management by operators. Exceptions to the application of high well construction oversight exist and are typically recorded in other oil producing countries – for example, in the case of methane contamination in Pennsylvania (Davis et al. 2012). Both large-scale movement such as low angle faulting (typically associated with subsidence or very high pressures) or small-scale movement like that seen at Preese Hall can damage wells. Long-term fatigue from multiple events is not listed as a cause in any of the case studies presented or reviewed, with limited evidence available to enable meaningful discussion.
Damage to surface infrastructure leading to release of contamination to environmental receptors	Single event ground shaking or liquefaction damaging infrastructure Cumulative build-up of seismic events of intensity greater than magnitude 5 (M5) inducing liquefaction settlements damaging infrastructure	There are very few cases from over the past few hundred years where seismic activity in England has caused much more than cosmetic damage to buildings and infrastructure during either induced or natural seismic activity. General construction design in the UK does not normally consider risks from seismicity and as such there is potential that small-scale support infrastructure such as some tanks and pipelines may not be able to withstand higher magnitude quakes (M5 and above). However, such magnitude quakes are very rare. Conventional reinjection activities carried out by operators in England are not known to be supported by the collection of seismic data, with no known record of conventional reinjection activities resulting in seismicity at any magnitude. In England, the only exception to this was the induced seismicity event at Preese Hall. This was related to shale gas exploration and fracking with the seismicity (M2.3) recorded still within the natural range known to occur in that part of the UK.

Potential risk area	Cause	Comments
		Although the process of liquefaction can pose real risks to surface infrastructure and buildings that may potentially lead to release of contaminants to the surface and/or groundwater, there is little to no evidence that soils and shallow sediments in England are overly susceptible to such actions – especially at the magnitudes that are typically associated with induced seismicity (that is, M2 to M5).
Fracture propagation between the reservoir and groundwater (including fracturing of strata that afford containment for the reinjected fluids) during the process of hydraulic fracture	Propagation of new fractures from source of reinjection at depth to receptor (that is, the aquifer)	Conventional reinjection is performed at relatively low pressures to: • dispose of produced water • maintain the reservoir pressure • improve the efficiency of oil displacement in the reservoir Operators usually reinject at below the rock fracture pressure to achieve a uniform water flood front, rather than having injected water channelling preferentially through induced fractures towards producing wells. Even if water is reinjected at above the fracture gradient, the typical depth of oil reservoirs in England is such that it is considered highly unlikely that such activities could result in the propagation of a fracture with a vertical height sufficient to connect the oil reservoir with an overlying groundwater receptor. Even for high pressure fracking (with pressures well above pressures required for conventional field water reinjection), the maximum fracture lengths monitored in the US are in the region of 500–600m with an average fracture height below 50m (Davies et al. 2012)].
Reactivation of existing fracture network and connection with shallow aquifer	Reactivation of existing fracture network from pressures higher than the existing reservoir pressure	Although this presents a potential risk, there is no evidence to suggest that this has been or will be an issue for onshore conventional fields in England. This is particularly true where operations put in place many of the mitigation elements detailed in Table 4.2. Given the tectonic regime in England, this may be more an issue for high pressure hydraulic fracturing where fracture propagation is more likely to cross-cut existing faults and fractures, potentially resulting in reactivation and potential slippage.

Notes: Adequate management of the potential risks is detailed in the following sections.

4 Guidance

This section provides generic guidance for determining what approaches should or could be applied in mitigating the risk of generating unwanted geomechanical impacts that may result in contamination of environmental receptors. It contains:

- an overview of the conditions that may give rise to geomechanical impacts based on the information from the literature review presented in Appendix A (Section 4.1)
- an overview of the general PWRI approaches employed in England and how such approaches may mitigate geomechanical impacts (bearing in mind the various conditions that may give rise to unwanted impacts) (Sections 4.2 to 4.4)
- a review of the applicability of the guidance to 2 other industrial activities, that is, carbon capture and storage and geothermal energy (Section 4.5)
- a review of alternative reinjection management approaches that may offer environmental benefits (Section 4.6)

The development of prescriptive controls (that is, identification of well completion details, specific flow rate, pressure, temperature and so on) is not possible because these factors will be site-specific and based on a variety of detailed analysis and modelling by an operator mindful of a given oil field's specific conditions.

Instead this guidance provides a broad overview of the variety of factors that need to be considered as part of a PWRI programme that should, where implemented appropriately, minimise and manage the risk of generating unwanted geomechanical impacts.

4.1 Conditions that give rise to geomechanical impacts

Geomechanical impacts such as induced seismicity or unwanted fracture creation and propagation from conventional reinjection activities are not common. No evidence was found to suggest these potential impacts have occurred in England in such a way as to present unacceptable risks to environmental receptors.

Table 4.1 provides an overview of the potential conditions that could give rise to geomechanical impacts as informed by international case studies. As noted above, these may not be appropriate for direct comparison to an English context.

Table 4.1 Overview of the potential conditions that could give rise to geomechanical impacts

Condition	Contributory factors required?	Outcome	Relevance in England
Pre-existing faults and fractures with tectonic stresses close to failure	Pressures used are greater than minor principal stresses and tensile strength of surrounding rock even where injection/reinjection of fluids is under relatively low pressures. Significant decline or increase in formation pressure	Potential reactivation of faults leading to slip and seismic events (for example, Dallas–Fort Worth case study – see Appendix A) Potential for reduction in shear stresses and resultant seismic event (for example, Lacq gas field case study – see Appendix A)	Has been noted in various case studies in tectonically active areas globally. UK geological setting makes this less likely to occur in England, with no evidence of this occurring in the past. More likely to be a concern for disposal wells where reinjection is into a non-producing formation (that is, risk of increasing pore pressures)
Pre-existing faults and fractures where stresses are not close to failure	Injection/reinjection of fluids under high pressures and volumes Significant increase in formation pressure	Potential reactivation of faults leading to seismic events (for example, as occurred at Preese Hall) or propagation of fractures beyond that intended (for example, Tordis field case study – see Appendix A)	Not relevant to conventional PWRI activities using relatively low injection pressures (typically <1,000–1,500psi at surface), injecting at below the rock fracture pressure and at low rates. No known evidence that this has occurred due to PWRI in England. More likely to be a concern for disposal wells where reinjection is into a non-producing formation (that is, risk of increasing pore pressures)
High injection/reinjection pressures applied	Pressures used are greater than minor principal stresses and	Potential creation of fractures that will only cease where injection pressure reduces to	Unlikely to occur in conventional reinjection activities where low pressures

Condition	Contributory factors required?	Outcome	Relevance in England
	tensile strength of surrounding rock	less than minor principal stress and tensile strength of the rock (that is, any induced fractures will close again)	(<1,500psi at surface) and rates are used and consideration is given to principal stresses and tensile strengths of rocks surrounding the reinjection well.
Reduction in reservoir pressure	Extensive extraction of fluids or gases that are not balanced via reinjection activities Highly compressible strata	Subsidence has occurred at various oil fields (for example, in the North Sea Ekofisk field after producing from a chalk formation). Potential for subsidence-induced seismic activity if there are significant movements	Not an issue in England to date as there have been no cases of significant subsidence attributed to conventional oil and gas field developments, let alone oil and gas field subsidence inducing seismic activity. Producing formations in UK oil and gas fields are relatively incompressible. Active reinjection programmes help to maintain reservoir pressure and further reduce the risk of significant subsidence.
Presence of pathways between reinjection interval and shallow groundwater aquifers	Well integrity issues due to poor design and construction methods Proximity to abandoned wells not properly plugged	Potential for leaks to occur where well integrity is not maintained (for example, east Pennsylvania case study – see Appendix A) Potential for pathway to be created if abandoned wells not properly plugged and located within the radius of influence of a reinjection activity	Unlikely to be natural pathways between injection formation and groundwater resources; operators applying for permits and licences are required to demonstrate, with a high degree of certainty, that such pathways do not exist. Well designs in the UK ensure multiple casing and cement barriers that are checked and examined to ensure that there

Condition	Contributory factors required?	Outcome	Relevance in England
			are no such pathways via wells. Suspended wells are monitored or permanently plugged and abandoned to required standards. Well integrity and abandonment procedures need to be rigorous and demonstrate with sufficient confidence that associated risks will not be realised.
Presence of liquefaction prone soils in proximity to critical infrastructure (for example, pipelines and tanks)	Induced or natural seismicity typically greater than M5 to M6	Potential for significant damage to infrastructure and release of contamination to environmental receptors	Limited areas of the UK are likely to have shallow ground conditions that would be susceptible to liquefaction, with very few seismic events ever expected to be greater than M4. No evidence of this having occurred in the past in the UK.
Aboveground structures not built to withstand seismic activity over a certain magnitude/European Macroseismic Scale (EMS) equivalent	Induced or natural seismicity typically greater than M4 to M5	Potential for damage to infrastructure not built to requisite standards and release of contamination of environmental receptors	Limited to no evidence from history in the UK to suggest any induced seismicity from conventional reinjection is large enough to result in damage to modern surface infrastructure. Some evidence that well damage may occur however during high pressure hydraulic fracturing (for example, Preese Hall case study in Appendix A).
Key parameters of reinjected fluids such as temperature and	Temperature gradient and geochemistry of receiving	Potential for damage to well infrastructure (for example,	Limited evidence to suggest this is a major contributor to

Condition	Contributory factors required?	Outcome	Relevance in England
chemical content not appropriate for reinjection depth and geology	formation not amenable to receiving fluid properties	corrosion and scaling) and potential for unwanted fracturing of formation geology (from temperature gradients)	geomechanical issues. Producing formations in the UK are relatively shallow (by international standards) and at relatively low temperatures, minimising the risk of thermally induced fractures due to water injection. However, a potential cause of unwanted damage to infrastructure that may lead to releases where not sufficiently controlled.
Poor regulatory oversight and unacceptable design and construction quality	Unchecked PWRI strategy resulting in inappropriate pressures, volumes and so on	Potential for damage to infrastructure, confinement problems or injectivity problems	May be a contributory factor in some international case studies, with limited to no evidence to suggest this is an issue in England.

Conditions that are not well understood – or at least not well represented in the literature reviewed – that may influence the potential for geomechanical impacts to occur include the following:

- Cumulative effects from adjacent oil plays considered conventional–conventional or even conventional–unconventional (that is, shale gas, coal bed methane or coal mine methane). Potential impacts from shale gas with regard to cumulative effects are particularly poorly understood due to the current absence of any activity in England.
- Potential for abandoned wells located in close proximity to operational wells to influence potential loss of containment and act as conduits for reinjected fluids to non-target formations. However, the potential for this depends on:
    - the quality of decommissioning
    - whether they complied with The Borehole Siting and Operations Regulations 1995 and The Offshore Installation and Wells (Design and Construction, etc.) Regulations 1996 (DCR)
    - whether there has subsequently been deterioration of the well structure
- Long-term fatigue within well construction materials from frequent low magnitude (that is, M1) seismic events. Such events are not directly recorded in terms of micro seismic monitoring in England and so the impact on infrastructure is not currently quantifiable. Data from the British Geological Survey (BGS) UK Microseismicity Array monitoring outputs show that many small magnitude earthquakes (for example, M1 to M2) are normal and relatively frequent. However, with over 2,200 onshore wells drilled in England, there are only 3 known subsurface well integrity incidents of contamination, all of which are understood to have been addressed by rapid well intervention work (OGA, personal communication).

4.2 Site-specific considerations

4.2.1 General approach in England

The review of the general practices employed in England for this project involved discussions with HSE and operators in England.

A summary of the general approach used when designing and implementing a PWRI programme in England is provided below. It focuses on those aspects that either directly or indirectly mitigate the potential risks of creating unwanted geomechanical impacts that could result in contamination to groundwater or other environmental receptors.

At the exploration stage, operators obtain and interpret geophysical, geological, petrophysical and engineering data relevant to the prospect to be drilled.

Faults are mapped from seismic data. Formation characteristics are predicted from offset well data. Well proposals are prepared taking into account any potential geomechanical issues.

Wells are designed with casing intervals to put multiple steel and cement barriers between produced and injected fluids and groundwater aquifers. Well designs are reviewed by independent well examiners and are approved by regulators.

During exploration, there is no produced water reinjection at the drilling site. Any water produced during testing of an exploration well will usually be transported from the site to other facilities for either potential reuse as make-up water or separation, clean up and disposal.

Prior to development, the operator prepares a field development plan (FDP) containing details of how the reservoirs will be managed, including any initial water injection plans. If produced water is to be reinjected, the FDP will include details of the proposed water injection well locations, the well designs, the formations into which the water will be injected, and the expected rates and pressures. Water injection will typically be at the edge of the field into rocks that from part of the same formation as the oil and gas accumulation to be produced. Injection pressures will normally be kept below the pressure required to fracture the formation. The FDP may include the results of a reservoir simulation model that can predict fluid saturations, reservoir pressures and well rates for the whole field life. The FDP will be reviewed by the OGA and other regulators where appropriate. Details of the content of a typical FDP are provided in Section 4.2.2.

If the FDP is approved and planning permission is granted, development wells will be drilled – obtaining further relevant data.

Water production is lowest when a field commences production and produced water may be exported with oil produced to another facility. If it is reinjected then one injection well may be sufficient. Natural water influx within the formation will usually replace part of the oil and gas produced. Over time, reservoir pressure will decline and water production will increase.

As field life continues and water production increases, the operator will consider converting high water cut or watered out or suspended production wells to injection. The well design will be reviewed to ensure integrity and sufficient barriers to prevent any groundwater contamination. If required, an initial injection test may be performed to confirm adequate injectivity. The operator may then carry out remedial well work or well stimulation prior to putting the well online for continuous PWRI.

During operations, all injection wells are monitored. Apart from injection rate and pressure, well annulus pressures are monitored to detect any tubing or casing leaks. Remedial work is performed if required. Injection pressures may be increased or a well may be re-perforated to increase injectivity in a particular reservoir.

When a field is abandoned, the wells will be permanently plugged to prevent any risk of communication between groundwater aquifers and deeper formations.

4.2.2 Field development plans

FDPs and FDP addendums are provided to the OGA by operators to:

- assist the overall aim of maximising the economic recovery of UK oil and gas resources
- ensure security of gas supplies

Geomechanical impacts and risks to environmental receptors do not feature within the content of such a plan. However, it may contain some information that helps the Environment Agency to understand what risks may be present.

Examples of potential content that may be relevant to the objectives of this report are given below.

Field description details

- Seismic interpretation and structure configuration. This could focus on the proximity of a well to existing fault and fracture systems.
- Geological interpretation and reservoir description. These details may help provide broad context on the geological and tectonic setting. Such information could provide context to the Environment Agency on potential risk profile of seismic activity (natural or induced).
- Well performance including assumptions used for the productivity and injectivity of development wells. This information may be used to develop the expected injectivity profile over the well's life. Such information may be useful to the Environment Agency to help identify issues of injectivity or loss of containment related to unwanted geomechanical impacts.
- Reservoir units and modelling approach including details on the extent and strength of any aquifers should be given. A brief description of how the field will be represented should be included – may be analytical, numerical or a combination of the two. Such information may be useful to the Environment Agency in understanding the broad conceptualisation of the reservoir.

Management plans

- Preferred development plans including details of the production profiles of all fluids (including produced water) and gas
- Field management plans stating principles and objectives that the licensees will hold when making field management decisions and conducting field operations. Although this part of the FDP is focused on how economic recovery of oil and gas activities will be maximised over the field life, this may be an area where consideration of unwanted geomechanical impacts could be included and how that would inform field management decisions.

4.2.3 Mitigating factors

When developing a PWRI strategy, field data are collected from geological mapping, geophysical investigations and exploratory holes. Various formation evaluation methods may be used (including coring, mud logging, wireline logging, electric logs, porosity logs, lithology logs or possibly including borehole breakout testing) to develop a detailed understanding of the subsurface with a focus on the tectonic setting, reservoir geology, magnitude and orientation of the principal stresses and properties of the adjacent confining layers.

An injectivity/falloff test may be conducted by the operator after well completion but before full-scale reinjection. The results can be used by rock mechanics and reservoir engineers to determine appropriate reinjection pressures, pumpable volumes, well bore skin factors and an array of other parameters relevant to a reservoir engineer's broader objectives which include selecting the most efficient reinjection system.

This process is not specifically looking at mitigating seismic activity, but on optimising the recovery of oil or gas by maintaining reservoir pressure and displacing the oil efficiently to producing wells. However, many of the conditions considered to potentially give rise to geomechanical impacts (see Table 3.1 and Table 4.1) may be inadvertently addressed by these approaches. Table 4.2 provides an overview of:

- how general international guidance (for example, OGP guidance) and general operational practices are or could be implemented before (that is, at the licensing and permitting stages) and during operations (that is, following well completion and during production)
- what actual approaches are typically applied in England based on discussions with regulators and operators prior to and during operations

Table 4.2 Mitigating factors in addressing geomechanical impacts

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
Critically stressed pre-existing faults and fractures	Reinjection pressures used are greater than minor principal stress and tensile strength of surrounding rock even where injection/ reinjection of fluids under relatively low pressures. Significant decline or increase in formation pressure	**As inferred in general guidance and good practice** Prior to operation: A comprehensive appraisal (including modelling) of the subsurface is typically completed as part of the development of a PWRI strategy. Studies should focus on the geology, regional tectonics, presence, depth and orientation of fault systems and subsurface pressures (both principal stresses and pore pressures) and temperatures to determine the appropriate reinjection fluid pressures and temperature for the specific site. During operation: Operators monitor well head pressures in the reinjection wells (and where available, with downhole pressure gauges and in observation wells). Monitoring of reservoir pressure could be more focused on comparison against modelled/trigger values so as to limit the risk of causing a slip-enabling perturbation of the stresses. Periodic injectivity and falloff testing may also be carried out to assess long-term performance. The temperature of reinjected fluids should be monitored to ensure that no adverse effects will occur should the temperature difference at depth be too great. Operators should have an established response should activation of a fault occur (that is, loss of containment) and ensure this is implemented as soon as possible. **As applied in England** Prior to operation: These preliminary activities are typically carried out during the development of a PWRI strategy **and** to support the application to obtain an environmental permit associated with groundwater activities. Conventional operations typically aim to reverse reservoir pressure declines from their initial pressure, which generally acts to limit the potential for geomechanical impacts.
Non-critically stressed pre-existing faults and fractures	Fast rate injection/reinjection of fluids under high pressures and volumes	
Propagating fractures within the rock mass	Reinjection pressures used are greater than minor principal stress and tensile strength of surrounding rock	
Contraction of the rock mass	Injection/ reinjection of fluids with a significantly lower temperature than the reservoir	

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		An environmental permit for a groundwater activity will require details to be provided on how the operator will determine the location, orientation and extent of induced fracture (mainly relevant for shale gas activities) and the likelihood of induced seismicity. The information should assess the risk of damage and the methods to be used to measure seismic activity, as well as the mitigation techniques to be used to reduce the likelihood and magnitude of induced seismic events. During operation: Although injectivity and fall-off testing is performed, such testing is infrequent and on an ‘as required’ basis (as determined by the regulators). Well head pressures are regularly monitored and recorded, but these data may not be shared with regulators. Some sites in England do have observation wells installed, but not all due to cost constraints. Reservoir depths are generally relatively shallow and reservoir temperatures in England are typically quite low, mitigating the risk of thermally induced fracturing even if injecting at ambient surface temperatures. Surface temperature is routinely monitored and recorded. Reservoir temperature is measured during exploration well logging and is assumed to remain relatively constant during field life. It is not routinely monitored and recorded during operations across industry unless there is a downhole temperature gauge installed. It would be possible to the regulator to impose downhole temperature monitoring requirements as part of the permit, although this will increase operating costs, may be solely of academic interest and would be subject to appeal. It is understood that, while individual operators will likely have established responses for each of their sites should there be a loss of containment or injectivity, these are not necessarily consistent across the industry and are not currently required to be shared with regulators and as such may not be collected.
Reduction in reservoir pressure	Extensive extraction of water that is not balanced via reinjection Highly compressible strata	**As inferred in general guidance and good practice** Prior to operation: A comprehensive appraisal of the subsurface by an operator’s reservoir and rock engineers is typically completed which focuses on the geology, regional tectonics, presence, depth and orientation of fault systems and subsurface pressures (both

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		principal stresses and pore pressures). Development planning includes estimating the expected rates of water production and determining an injection strategy. In a primary recovery strategy, produced water will be disposed of without reinjection and reservoir pressure will be allowed to decline. An FDP with a secondary recovery strategy will typically include at least produced water reinjection and may also include additional water and/or gas injection to enable an effective net balancing of produced and reinjected fluids with full voidage replacement. During operation: Ongoing monitoring of the net balance of fluids extracted and reinjected typically takes place and the results recorded. Reservoir engineers recommend changes in reservoir management strategy to increase the recovery factor. The motivation to increase reservoir pressure is generally to increase production rather than to mitigate the risks of subsidence or induced seismic events. **As applied in England** Prior to operation: UK onshore FDPs have historically relied on primary recovery only with pressure decline, natural water influx and artificial lift. Produced water rates have justified reinjection and on some fields there have been actively managed water floods rather than simply water disposal. Injectivity and falloff testing may be conducted to plan water flooding. Regular monitoring of reservoir pressure is known to be carried out by operators in England in both reinjection wells and observation wells (where installed and available), but this information is often not shared with regulators. One onshore activity that may result in a reduction of reservoir pressure is the exploitation of coal bed methane. In England, it is currently understood that the abstraction of water to exploit coal bed methane does not require an abstraction licence or environmental permit associated with water abstraction activities. However, this is likely to change during 2016 and these preliminary activities would typically be carried out to support this application.

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		During operation: Operators typically record the total volumes of fluids produced and fluids reinjected. It may not be necessary or cost-effective to maintain reservoir pressure. Reservoir engineers recommend changes in the reservoir management strategy to increase the recovery factor and may wish to ensure a net balance over time.
Presence of potential migration pathways between reinjection interval and shallow groundwater aquifers	Well integrity issues due to poor design and construction methods Proximity to existing or abandoned wells Reactivation of faults connecting reservoir and aquifer	**As inferred in general guidance and good practice** Prior to operation: Any well design (new or modified) should ensure that no pathways are created between the producing reservoir and any groundwater bodies or other environmental receptor. A well should also be designed bearing in mind the pressures planned to be applied, and an appropriate factor of safety when operational such that its integrity is maintained throughout its operational life. BAT should be employed where available during drilling activities and established good practice should be followed on all other related production activities. An appraisal should also be carried out to determine if any existing or abandoned wells are located within the zone of influence of reinjection and whether such a well may act as a pathway. Taking account of source protection zones (SPZs) also needs to be factored in, with consideration of both lateral (on which SPZs are primarily determined – that is, travel times) and vertical implications clearly presented. Regarding distances, consideration should be given to establishing a suitably safe distance such that pathways are not created through unwanted fracture propagation or fault reactivation, especially where horizontal drilling is performed. This approach is likely to require site-specific assessments bearing in mind the volumes, pressures and rates, the well's design and construction details, and the site's geological and tectonic setting. During operation: A well should be subject to regular mechanical monitoring using a variety of methods to ensure its integrity is maintained. Such monitoring may include one or a combination of the following: annulus pressure monitoring; pressure testing of the well; temperature logging; noise logging; pipe analysis survey; electromagnetic thickness survey; caliper

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		log; borehole televiewing; flowmeter survey; radioactive tracer survey; oxygen activation logging; and cement bond logging. **As applied in England** Prior to operation: A groundwater activity permit from the Environment Agency is needed before drilling a well where groundwater is considered to be at risk. The permit may take account of risk considerations such as geological structures that may be affected (for example, faults and fracture systems identified from various reservoir evaluation methods). The use of BAT is essential in mitigation. In addition to a groundwater activity permit (where one is required and obtained from the Environment Agency), HSE requires notification before the drilling of the well, any work over on the well, any modification, and before the abandonment of the well. HSE would expect weekly reports for these activities with its main interest focused on ensuring that injection pressures do not exceed the pressure integrity of the well. HSE would not normally request details of the injectivity and falloff tests apart from information on the operator's planned activity, which may be included in the well notification. Once the well is drilled and completed, HSE no longer receives any further information. During operation: HSE has a minimal role in overseeing the general operations and would typically only be informed if any modification was being made or if there was an unplanned release of fluids from a well, deployment of safety equipment to prevent an unplanned release of fluids, or other event reportable under Schedule 2 of the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations (RIDDOR), the receipt of a complaint about the operation or the receipt of a further notification (for example, prior to abandonment). The Environment Agency does not typically receive any information regarding the ongoing operation of hydrocarbon-related wells unless there has been a reported release to the environment and/or where a specific contravention of a permit has been identified, or where a permit condition specifically requires this.

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		Operators in England routinely review the proximity of abandoned wells and, if present, what condition they are in and whether they may pose a risk in terms of potential pathways. Operators routinely check tubing and annulus pressures. It is not clear what other methods of mechanical monitoring are typically carried out on an operator's well and it is likely to vary between operators.
Presence of liquefaction prone soils in proximity to critical infrastructure (for example, pipelines and tanks)	Induced or natural seismicity typically greater than M5 to M6	Liquefaction is not considered a significant risk in England that would warrant specific attention and as such is not included here. However, should oil or gas activities be planned in areas close to running sands, further assessment should be made to understand the potential implications in the event of seismic activity as these deposits may be susceptible to liquefaction at lower magnitudes than more typical sand deposits.
Key parameters of reinjected fluids such as temperature and chemical content not appropriate for reinjection depth and geology	Geothermal gradient and geochemistry of receiving formation not amenable to receiving fluid properties	**As inferred in general guidance and good practice** Prior to operation: As part of the development of a PWRI strategy, reservoir and rock mechanics engineers should determine appropriate temperatures and geochemical parameters to optimise operations and recovery of oil or gas without adversely affecting well integrity or creating unwanted fractures within the reservoir. BAT and established good practice for prevention of pollution should be employed when designing and constructing onsite produced water treatment systems. During operation: Regular monitoring of the reinjected fluids temperature should be carried out to ensure no adverse effects will occur should the temperature difference at depth be too great from that modelled during the development of a PWRI strategy. Produced water may be treated prior to reinjection as required based on PWRI strategy outputs. **As applied in England** Prior and during operation: It is understood that, as part of a PWRI strategy, a geochemical appraisal of produced waters will be made with onsite treatment systems designed and constructed to enable

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		effective reuse of produced waters as required. However, some sites may not require pre-treatment and may just reinject produced waters directly after separation of oil and water. The full process and consistent application of this is, however, not well defined and would require detailed discussions with each operator. It is not clear how consistently temperature is modelled in planning stages or monitored during operations across industry.
Aboveground structures not built to withstand seismic activity over a certain magnitude/EMS equivalent	Induced seismicity typically greater than M4 to M5	**As inferred in general guidance and good practice** Prior to operation: As part of the PWRI strategy, reservoir and rock mechanics engineers should consider the potential for inducing seismicity and evaluate the local structures to ensure their integrity will not be compromised. If there is any intention to exceed formation pressure and 'break the formation', operators must inform OGA in much the same way they would if carrying out high volume hydraulic fracking (HVHF). During operation: If it is deemed that there is potential to induce seismicity during the reinjection operation, the operator should consider having a monitoring system (such as a microseismic array) in place to capture any induced seismicity and a strategy in place for reducing/increasing the pressure (should under or over abstraction be the cause of seismicity) in the reservoir should any events occur. Balancing a system of this size would not result in an instantaneous response with the potential for a lag time to occur. Such outcomes should be considered at the planning stages and used to inform emergency response plans for the operations. **As applied in England** Prior to operation: Critical infrastructure[1] in England generally has a seismic design based on Eurocode 8[2] or site-specific study to capture natural seismicity. These types of structures are highly unlikely to have their integrity influenced by any induced events associated with

Condition	Contributory factors to geomechanical risks	General mitigating factors that are typically applied (or could be applied) for reinjection operations in England
		reinjection. Less critical structures may not have a seismic component to their design and as a result are more likely to be influenced by induced seismicity, if any. There is currently no plan to develop a UK seismic hazard map accounting for reinjection activities. Should reinjection activities expand in the UK, however, it may be necessary to consider the application of Eurocode 8 to a lower class of structure in potentially affected regions. Reinjection activities in conventional fields are likely to remain at the present low level. During operation: Currently there is no requirement or guidance/legislation on the monitoring of seismic activity for conventional reinjection operations. A traffic light system is in place for the shale gas industry (that is, for high pressure hydraulic fracturing activities and no reinjection of produced water), but conventional operators would likely appeal should such a requirement be placed on conventional activities.
Poor regulatory oversight and unacceptable design and construction quality	Unchecked PWRI strategy resulting in inappropriate pressures, volumes and so on	There are no known geomechanical impacts that have resulted in the contamination of environmental receptors in England. This may in some part be due to the rigorous licensing process that is in place and the relatively small-scale nature of the onshore oil and gas industry in England. As the industry develops over the coming years, it will important for the Environment Agency, local planning authorities, HSE, OGA and BEIS to work closely together to ensure that the above aspects are adequately considered, addressed and clearly reported at the petroleum exploration and development licence (PEDL), permitting and notification stages prior to full-scale operation. This would enable consistent decision-making when regulating these activities.

Notes: [1] The UK's national infrastructure is defined by the government as: ‘Those critical elements of infrastructure (namely assets, facilities, systems, networks or processes and the essential workers that operate and facilitate them), the loss or compromise of which could result in: a) major detrimental impact on the availability, integrity or delivery of essential services – including those services, whose integrity, if compromised, could result in significant loss of life or casualties – taking into account significant economic or social impacts; and/or b) significant impact on national security, national defence, or the functioning of the state’ (www.cpni.gov.uk/about/cni/).
[2] EN 1998: Design of structures for earthquake resistance

4.3 Key aspects to consider when designing and implementing a PWRI strategy

PWRI in conventional onshore oil and gas fields in UK takes place at relatively low rates and pressures. The literature review and input from UK onshore operators indicate that adequate procedures are currently in place and there have been no incidents of inducing seismic events due to PWRI.

This section presents a summary of the key aspects for consideration when designing and implementing a PWRI strategy that minimises the risk of inducing unwanted geomechanical impacts. The summary presents:

- general data requirements needed to develop a robust PWRI strategy (Sections 4.3.1 and 4.3.2)
- monitoring and mitigation measures required during implementation and operation (Section 4.3.3)

4.3.1 Data presentation

For an operator, the collection of these data helps with:

- licence applications (for example, PEDL licence) and subsequent permitting (for example, groundwater activity permit)
- development of a robust PWRI strategy to ensure optimised operations

As such, presentation of the data may be spread over a number of documents for sending to a number of different regulators (for example, OGA, BEIS, Environment Agency and HSE) or statutory consultees (for example, BGS and the Coal Authority) and may not be presented in one overarching document.

Should the information discussed below be required to inform subsequent permitting for reinjection activities, it could be beneficial to present this information within one submission. However, the information needs of the regulators are different, as are the timing requirements for review of information submitted. A ‘joined up’ approach by the regulators is urged to:

- avoid duplication in preparation of information by the industry
- ensure the regulators use common criteria to judge the same information

4.3.2 Data collection

In broad terms, there are a number of different types of information that are (or could be) collected to enable assessment of the potential geomechanical hazards on which risk assessments depend and are therefore used in developing a broader PWRI strategy. These include:

- injection pressures, duration and volumes
- sufficient data on the geomechanical aspects of the subsurface geology including:

  - net pore pressure within the relevant formations and in situ stresses and orientations within the relevant reinjection formations (including confinement layers) and any faults present in the area
  - depth of reinjection interval in relation to any SPZs that may be present, including establishment of an appropriate minimum safe distance to enable drilling and reinjection activity to progress safety
  - the tensile strength of the reservoir rock and any overlying formations
  - information on existing fault systems such as depth, length and orientation that may be present in the area and which may cross-cut reinjection wells as well as other relevant formations (that is, confinement layers or shallow aquifers)
  - geothermal gradients across the relevant formations, expected temperature gradients between relevant formations and reinjection fluids and a modelled understanding of the impact of such temperature changes on the reservoir geology
- background seismicity for the area of interest and an understanding of the regional tectonic regime and how it may respond to changes in subsurface pressures and temperatures
- identification and condition of any other types of potential pathways between the reservoir and any shallow aquifers such as existing or abandoned wells
- an understanding of other proximal activities associated with conventional or unconventional oil and gas, geothermal and/or carbon capture and storage, and how these may affect planned reinjection activities (that is, potential for cumulative affects)

4.3.3 Monitoring and mitigation

The types of monitoring and mitigation measures that are or could be employed to minimise the potential for geomechanical impacts include:

- injectivity and falloff testing and subsequent periodic re-testing over the lifetime of the well to identify potential pressure build-up (loss of injectivity) or pressure reduction (insufficient injection)
- provision of a clear and established response in the event of any situation that could cause an unwanted geomechanical impact
- ongoing monitoring of agreed reinjection pressures in reinjection wells based on a comprehensive assessment by subsurface engineers during the development of the PWRI strategy
- where available, ongoing monitoring of agreed reinjection pressures in observation wells
- ongoing monitoring of the net fluid balance within the reservoir to ensure adequate reservoir management
- regular monitoring of reinjection fluid temperatures to ensure the temperature gradient in the formation is maintained within acceptable levels

- provision of compliant HSE notifications for any new well or amendment to a well
- completion of regular mechanical maintenance to identify any potential integrity issues within a well
- construction of critical infrastructure capable of withstanding potential seismic activity of up to M5

Microseismic monitoring is another potential approach that could be adopted. However, this is not currently carried out on an industry-wide scale and would incur significant additional and unplanned costs for operations on conventional fields. Microseismic monitoring is planned for large-scale hydraulic fracturing of some proposed UK shale wells but, at this time, the industry view is that there is no justification for microseismic monitoring of PWRI operations.

4.4 Application of the collected data

Table 4.4 provides an overview of how the collected data listed in Section 4.3.2 can be presented and assessed to aid review of permits for reinjection activities on conventional onshore oil and gas activities.

Table 4.3 Overview of presentation and use of collected data to aid review of permits for reinjection activities

Information to be collected	Potentially acceptable data range	Considerations for permitting body
Data collection		
Injection pressures, volumes and duration	Pressures, volumes and duration to be determined based on reservoir modelling. However, typical conventional reinjection surface pressures range between 1,000 and 2,000 psi	Request and review information on proposed injection pressures, volumes and duration in relation to other aspects detailed below (for example, pressures relative to the ability of the surrounding rocks to accept tensile stresses). Are the data presented to enable easy assessment of whether pressures are appropriate? Review of these data should be take into account other factors such as: • existing in situ pressures within reinjection formation • presence, proximity and orientation of any fault systems • tensile strength of the rocks Injection pressures will greatly depend on the depth of reinjection formation and pre-existing pore pressures and may be as low as 300–400psi or be above 2,000psi.
Net pore pressure within the relevant formations and in situ stresses and orientations within the relevant reinjection formations (including confinement layers) and any faults present in the area	Site-specific (based on site-specific modelling and evaluation)	Permit reviewer should request data from reservoir evaluation models (numerical, analytical or graphical) on: • tensile strength/fracture ceiling of the surrounding rock and of any fault systems in the immediate area • net pore pressures within reinjection formations and how close pore pressures are to exceeding the tensile strength/ fracture ceiling of the surrounding rock • provision of in situ stress field details (where available)* • specific details on known faults and fractures, their orientation and proximity to the well activity

Information to be collected	Potentially acceptable data range	Considerations for permitting body
		* High risk stress orientation to be identified by the operator depending on their activities and the orientation of any fault systems in close proximity to well. The level of detail for this information may vary from operator to operator. Establish a minimum safe distance based on the intended reinjection radius of influence (based on reinjection volumes, duration and pressures) as inferred from reservoir modelling.
Depth of reinjection interval in relation to aquifers that may require particular protection measures including establishment of an appropriate minimum safe distance to enable drilling and reinjection activity to progress safety	Distance of 1000–1200m[1] beneath designated groundwater bodies[2] or protected groundwater source areas respectively	Review the geological conceptualisation of the oil play and surrounding area – as per information presented in either the FDP or environmental permit (that is, groundwater activity permit). Confirm drilling depth beneath known SPZ or protected groundwater bodies (if present in area of reinjection). Activities proposed above the specified depth limits are not acceptable.
Tensile strength of the reservoir rock and any overlying formations	Site-specific and dependent on proposed injection pressures	Request and review information from reservoir evaluation methods or modelling outputs used to determine the rock's tensile strength. Seek confirmation from the operator of injection pressures relative to the tensile strength of surrounding rocks and whether activities could result in fracturing or activation of faults (if present). Request and review details on tensile strength of overlying formations and whether these will be susceptible to faulting or collapse in the event of over or under pressurisation of the reservoir (for example, where the broader reservoir pressure is not balanced effectively).
Information on existing fault systems such as depth, length, and orientation, that may be	Site-specific	Review geological conceptualisation information as presented in the FDP and/or a groundwater activity permit.

Information to be collected	Potentially acceptable data range	Considerations for permitting body
present in the area and which may cross-cut reinjection wells as well as other relevant formations (that is, confinement layers or shallow aquifers)		Use this information to help identify whether fault systems cross-cut intended reinjection wells or are within the radius of influence of a reinjection activity. If present, request further assessment on how the potential for geomechanical impacts will be mitigated.
Geothermal gradients across the relevant formations, expected temperature gradients between relevant formations and reinjection fluids and a modelled understanding of the impact of such temperature changes on the reservoir geology	Site-specific with no known criteria determined	May be more relevant for geothermal projects or oil and gas wells in areas of high geothermal gradients (that is, geothermal gradients >25°C per km). Request geothermal gradient details from the operator including known temperatures within reinjection formations at depth and planned temperatures for reinjected waters. Consider whether permit condition should be included requesting an assessment of the potential impact of reinjection of waters with large temperature differences compared with the receiving formation.
Background seismicity for the area of interest, an understanding of the regional tectonic regime and how it may respond to changes in subsurface pressures and temperatures	Site-specific data	Review information presented in the FDP and/or a groundwater activity permit. Use this information to help identify what potential stresses already exist within the proposed area of oil production and if planned pressures, volumes, duration and temperatures may alter the stress regime adversely in the area (that is, have potential to fracture rock and/or reactivate faults in the area). This information provides a good understanding of pre-existing conditions and could be used to inform baseline data for the permit. It may also help to determine future geomechanical impacts from the proposed activity and allow proactive mitigation to be employed.
Monitoring and mitigation		
Injectivity and falloff testing and subsequent periodic re-testing over the lifetime of the well to	Site-specific data	Request information on whether injectivity testing and modelled injectivity expected for the field over its lifespan have been performed and the results are available. Where undertaken, the most useful data will be obtained during

Information to be collected	Potentially acceptable data range	Considerations for permitting body
identify potential pressure build-up (loss of injectivity) or pressure reduction (insufficient injection)		operation and used to assess general well performance and whether reinjection activities have resulted in a loss of containment or loss of injectivity. The ideal is to see a constant pressure curve. Although this information is not consistently collected and may not be available from all operators, the permit reviewer could consider including this information request as a permit condition.
Provision of a clear and established response in the event of any situation that could cause an unwanted geomechanical impact	Provision of established response plan	Request details on what mitigations are in place to respond to an event that may cause unwanted geomechanical impacts. As a minimum, response should include consideration of: • well integrity issues • unwanted fracture propagation • reactivation of faults • loss of injectivity or containment potentially suggestive of the issues above The plan should also consider impact of the potential lag time between implementation of a change of surface operations and the desired response within the subsurface.
Ongoing monitoring of agreed reinjection pressures in reinjection wells based on a comprehensive assessment by subsurface engineers during the development of the PWRI strategy	Site-specific, but reinjection surface pressure typically within 1000–2000psi	Request and review detail from ongoing pressure monitoring data collected over the lifespan of the field operations. This should ideally be provided with any injectivity testing results and include details of mitigations that may have been required in response to any injectivity (or other) issues. Injection pressures will greatly depend on depth of reinjection formation and may be as low as 300–400psi if in shallow formations. Consider including this request as a permit condition.
Where available, ongoing monitoring of agreed reinjection pressures in observation wells	Site-specific and only where there are observation wells	Request data and review reservoir pressures in observation wells (where installed) and compare with reservoir model (that is, expected pressures at a given distance from the injection well) and net pore pressure prior to operations.

Information to be collected	Potentially acceptable data range	Considerations for permitting body
		This information will not be available at the time of permitting (that is, observation wells and ongoing monitoring to be conducted once the well is producing) and unlikely to be available for many sites as observations wells are generally installed at the discretion of an operator. Could be considered as a permit condition where observation wells already exist or are planned by the operator.
Ongoing monitoring of the net fluid balance within the reservoir to ensure adequate reservoir management	Site-specific and dependent on site operations	Request and review net fluid balance data, which should support planned reservoir management strategy. They are unlikely to inform permitting as data are only collected during production, and may not be collected consistently (or at all) by different operators. Could be considered as a permit condition.
Provision of compliant HSE notifications for any new well or amendment to a well	Provision of HSE notifications (as required)	General requirement is for HSE to follow. However, the Environment Agency could request information to help support its understanding of the ongoing activities at a site.
Completion of regular mechanical maintenance to identify any potential integrity issues within a well	Provision of information to HSE and Environment Agency	Not mandatory to provide and only collected at the discretion of the operator. Potential opportunity to request such information to be collected as part of permit conditions.
Construction of critical infrastructure capable of withstanding potential seismic activity of up to M5	Only relevant if considered critical infrastructure	If development meets the criteria of critical infrastructure as determined by the Centre for the Protection of National Infrastructure (CPNI), consideration must be given to ensuring its ability to withstand earthquakes up to M5. Eurocode 8 Part 4 provides details on the design of structures for earthquake resistance for silos, tanks and pipelines (CEN 2006).

Notes: [1] Based on minimum distances as stated in the Petroleum Act 1998, as amended by the Infrastructure Act 2015, and government's proposed 1200m minimum distance for a protected groundwater source area. Both these values relate to hydraulic fracturing and are likely to be overly conservative when used for assessing conventional reinjection activities.

[2] Groundwater bodies as defined under the Water Framework Directive

4.5 Applicability to other industries

Other major industries that undertake reinjection activities and which are considered to be relevant to England include:

- carbon capture and storage (CCS)
- geothermal heating schemes

Both industries require injection or reinjection of either liquids or compressed gases to deep formations.

The following sections provide an overview of the processes involved and outline whether the guidelines set out in Table 4.3 are applicable.

4.5.1 Carbon capture and storage

Carbon capture and storage involves the capture of carbon dioxide at the source of generation and subsequent storage in deep formations. Also known as geosequestration, it involves injecting carbon dioxide, generally in supercritical form, directly into underground geological formations.

A number of potential storage sites are considered as being potentially appropriate storage sites including oil fields, gas fields, saline formations, un-mineable coal seams and saline-filled basalt formations.

In some parts of the world, carbon dioxide is sometimes injected into declining oil fields to increase oil recovery. Approximately 30–50 million tonnes of carbon dioxide are injected annually in the USA into declining oil fields (Metz et al. 2005). In oil producing regions of the world, particularly in the USA, this is considered an attractive option as the geology of hydrocarbon reservoirs is generally well understood and storage costs may be partly offset by the sale of additional oil that is recovered (Energy Institute 2010).

In England, carbon capture and storage is not an established industry with only one notable project (White Rose in Yorkshire) currently progressing at the front end engineering design (FEED) stage.

While the process of carbon capture and storage is different to the produced water reinjection process, the geomechanical implications of injecting gases at pressure in deep formations are similar. The Cogdell case study detailed in Appendix A highlights the potential for induced seismicity to be associated with gas injection activities and therefore warrants consideration when regulating such sites.

In terms of the geomechanical implications of undertaking a carbon capture and storage scheme, the major similarities between reinjection schemes and carbon capture and storage projects are considered to be significant.

Work carried out by the International Energy Agency in the USA identified that the potential risks associated with induced seismicity at carbon capture and storage sites can be reduced and mitigated using a systematic and structured management programme (Gerstenberger et al. 2013). Moreover, it was asserted that existing statistical stochastic models show the most promise for forecasting seismicity, although improved deterministic physical models are under development and may be the key in the future. Clearly, both types would need to be tailored to any investigated injection sites.

Carbon capture and storage site performance and management guidelines should be established prior to injection to facilitate:

- definition and determination of the acceptable threshold limits and impacts of induced seismicity
- optimisation of the monitoring and mitigation programmes
- establishment of important control measures that allow effective risk management

In the steps required to be carried out as part of the characterisation of the storage dynamic behaviour, sensitivity characterisation and risk assessment of carbon capture and storage schemes, Directive 2009/31/EC (Council of the European Union 2009) identifies the need to perform appropriate dynamic modelling to provide insight into the potential of induced seismicity.

Guidelines developed for enhanced geothermal systems are considered capable of providing the starting point for a management strategy of induced seismicity at carbon capture and storage sites.

4.5.2 Geothermal heating schemes

Geothermal energy is the energy stored in the form of heat beneath the Earth's surface. Geothermal heating schemes, including geothermal plants, represent the exploitation of this geothermal heat. In the UK, these schemes are typically premised on the abstraction of deep geothermally heated groundwaters that are then reinjected into the same formation. Figure 4.1 provides a simplified schematic of a typical geothermal plant.

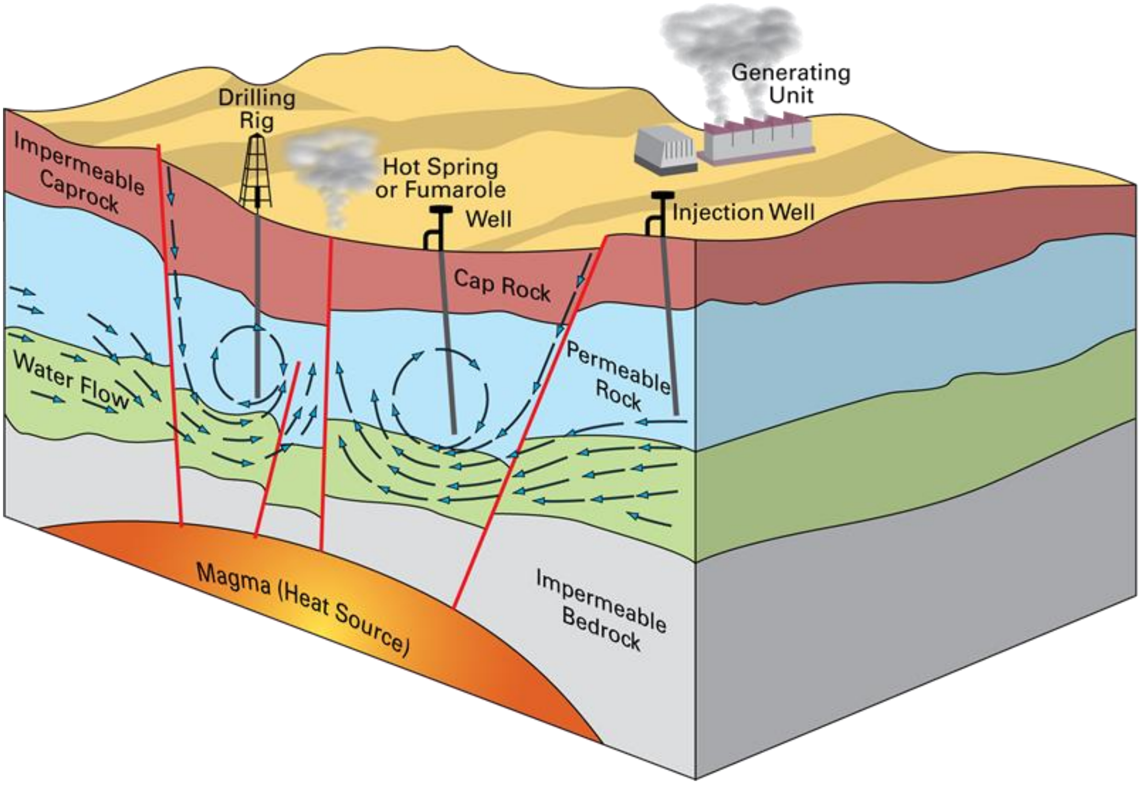

Figure 4.1 Typical geothermal project in England (such as that used in the Southampton District Heating Scheme)

Notes: Not to scale

The overall geomechanical aspects requiring consideration are broadly similar to those detailed in the preceding sections as geothermal heating schemes also require reinjection of fluids under pressure to deep formations that are geomechanically similar and subject to similar tectonic stresses.

The major difference between the reinjection of produced water into oil and gas reservoirs is typically related to the geothermal gradient and temperature differences at depth. In addition, the geology associated with geothermal projects is often crystalline basement rock. This can store greater amounts of seismic energy before failure, unlike sedimentary rocks such as shales or interbedded clastic rocks.

Induced seismicity in geothermal projects is triggered by anthropogenic changes to the geostatic stress regime, which makes the tectonic setting an important variable to consider. High temperature geothermal reservoirs are typically located in active tectonic settings where high levels of natural (as opposed to induced) seismicity are common. But as observed in Basel, Switzerland (Deichmann and Ernst 2009) and the Cooper Basin, Australia (Asanuma et al. 2005), felt events can occur in areas of relatively low tectonic strain rate.

Fluid pressures also play a key role, in that, if pore pressure is great enough to overcome the effective normal stress, shear failure may occur. The process of seismicity triggering in these settings can be linked to a change in pore pressure and degree of ‘roughness’ of a fault. One suggested mechanism is that increasing pore pressure causes asperities (or locked points) on the ‘rough’ fracture surface to fail, thereby allowing movement on the naturally stressed fracture.

Other factors that may affect geothermal seismicity include:

- displacement stresses associated with volumetric contraction caused by fluid extraction
- thermal stresses created by injection of cool fluids into hot rock formations
- chemical stresses associated with injection of brines or acid fluids, which can have a weakening effect on the rock

The levels of induced seismicity (that is, number of events and magnitudes) depend on a number of background factors. These include:

- local stress regime
- fault orientation and locations
- friction

Levels also depend on controllable factors such as:

- injection pressure and temperature
- volume injected
- duration of injection
- injection ramping rates

However, the uncertainties involved and the variability between geological settings make it difficult to establish reliable correlations between the level of seismicity and any of these factors that could be consistently applied to new settings (Evans et al. 2012).

4.6 Other fluid management approaches

There are limited sustainable alternative disposal/treatment routes for flowback and produced water within England. Potential options include:

- disposal of water to public (foul) sewer without treatment
- treatment and disposal of water to public sewer
- treatment of water and disposal to surface water
- tankering of water to an appropriately licensed facility for treatment and disposal

This section sets out the most important considerations for identifying the best environmental option for disposal of produced water arising from conventional onshore oil and gas fields. It takes into account likely cross media impacts including the generation of wastes that then themselves require treatment and atmospheric impacts from transport.

Elsewhere in the world, evaporation-based solutions are often employed. In the context of the UK climate, however, this is highly unlikely to be effective. The Environment Agency has stated that this would not be considered BAT for managing water in the oil and gas sector and thus is not considered further.

In each case, site-specific assessment is required, taking into account the nature of the produced water generated at that particular site.

For the purposes of this discussion, however, it is assumed that produced water is likely to contain:

- high levels of dissolved salts (total dissolved solids) including chlorides and sulphates
- naturally occurring radioactive materials (NORM) – where concentrations are above the 'out of scope'[2] criteria, the fluids are characterised as NORM and subject to radioactive substance regulations
- low levels of dissolved hydrocarbons

Where disposal to sewer is considered, the regulatory requirements imposed on the recipient (for example, the sewerage undertaker) will affect the acceptability of this route. These will be local environmental factors as well as the Water Framework Directive status of the receiving watercourse and the requirements of other directives (for example, the Bathing Water Directive and the Urban Waste Water Directive).

Where injection of water is required to maximise the recovery of oil and/or gas, it is likely that reinjection of produced water will be preferable to the use of fresh water to fulfil this function and can be considered to be recovery.

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[2] 'Out of scope' refers to the concentration of NORM that exceeds specified values. The criteria used to determine if concentrations are out of scope are provided in NORM Guidance for Industrial Activities (February 2013 Version 1). The criteria used to determine if concentrations are out of scope are based on the radionuclides at the top of each of the 3 natural decay series: radium-226, radium-228, lead-210 and polonium-210.

4.6.1 Disposal to sewer without treatment

Where there are appropriate sewers with sufficient flow capacity to accept produced water, it may be technically feasible to dispose of the water to this system so that it is then treated by the sewerage undertaker along with other waste waters. Any such arrangement will be subject to commercial discussions between the operators of the 2 facilities.

Key issues affecting the environmental suitability of the disposal of untreated produced water to sewer are likely to be:

- the impact of the high salinity waters on the treatment systems in place at sewerage undertaker’s facility, especially for more rural locations where dilution by other waste streams may be limited
- the potential for the produced water to give rise to breaches of the sewerage undertaker’s permit conditions, taking into account the treatment processes currently employed at the site (that is, by increasing the discharged concentrations above the limit values)
- the generation of solid wastes and sludges that cannot be treated by currently used methods (for example, incineration or anaerobic digestion) either because it could breach air quality limits or give rise to residual wastes that are problematic
- the additional volume of water may, in some cases, increase the risk of additional overflows which could result in breaches of urban waste water regulations – though some production site flow balancing may be possible to mitigate this

4.6.2 Disposal to sewer after treatment

Where there are sewers with appropriate flow capacity, it may be possible to treat produced water and discharge this to the sewer network. A crucial driver in the degree of treatment required may be the effort needed to avoid the problems listed in Section 4.6.1, though the potential impact of the volume of their risk of overflow of course remains.

Due to the nature of the produced water, treatment options can be limited and much of the contamination cannot be destroyed but merely precipitated or concentrated. This therefore has the potential to generate more difficult wastes (for example, brines or precipitates) for which disposal options are highly limited. Similarly, it is likely that the treatment options may give rise to increased NORM concentrations, which may also be problematic. Further treatment to stabilise these materials may therefore be needed.

The treatment methods are also likely to be energy intensive and therefore may give rise to atmospheric emissions, albeit probably some distance from the site.

The wastes generated by the water treatment process will require offsite disposal and therefore will give rise to traffic emissions as well as potential impacts on local residents.

4.6.3 Treatment and discharge to surface water

Where a stream or river is present, it may be appropriate to discharge water to this. In many cases, however, it will be necessary to construct a pipeline or ditch enable this.

Treatment will almost always be required to enable this discharge, with an assessment of the impact using the Environment Agency's 'H1' software tool[3] required. The potential negative impacts of onsite treatment apply equally to this option, with offsite disposal of difficult wastes likely to be required. In addition, environmental quality standards for surface water are now based on very low limits. Treatment for discharge to surface water is therefore likely to require more energy inputs than for a discharge to a sewerage system to achieve these lower standards.

4.6.4 Tankering off site

Where other options are not available, it may be necessary for waste water to be removed from site and transported to an appropriately permitted treatment facility, either run by the operator or a third party. Where large volumes of water require treatment over extended periods, this is unlikely to be an environmentally attractive option due to the effects of the traffic on the local and global environment.

[3] www.gov.uk/government/collections/risk-assessments-for-specific-activities-environmental-permits

5 Data gaps for further review

This report identifies a number of data gaps or potential uncertainties. These are either gaps from the available information it was possible to access within the bounds of the study or where there are fundamental gaps in the industry's knowledge. The data gaps identified thus far include:

5.1 Gaps in available information

- In the absence of any explicit guidance in England on conventional reinjection activities to what extent is the OGP guidance implemented in onshore operations?
- Has long-term fatigue damage ever been noted in well casings or general infrastructure from long-term small magnitude (M1 to M2) seismic activity?
- What EOR techniques are practised in England and has any induced seismicity been linked to their use, even at low magnitudes (that is, M1 to M2)?
- What are the relative pressures at which reinjection occurs? This is generally unknown for onshore English operators.

5.2 Gaps in industry knowledge

Data gaps in industry knowledge that may warrant further study include the following.

- The general lack of conclusive root causes presented in reviewed case studies suggests that the amount of data available from oil fields that have recorded induced seismicity is insufficient to enable robust and conclusive investigations. However, this is likely to be linked to the inherent complex nature of the subsurface geology, particularly in relation to established oil plays, making full subsurface characterisation very challenging.
- There is a general absence of detailed seismic monitoring data in areas of oil and gas production, beyond any general seismic arrays that may exist for research purposes such as ongoing BGS studies (that is, the industry does not collect microseismic or seismic data during production). Such data would enable robust assessment of the frequency and magnitude of PWRI programmes.
- The low frequency of established links between seismic activity induced damage and the contamination of environmental receptors suggests this is a rare occurrence globally. Is this because this generally does not occur, or is this due to under reporting? Alternatively it could be a result of a general absence of sufficient evidence to support a causal link.
- What temperature differences between reinjected waters and receiving formation could cause geomechanical impacts?
- The most appropriate means of determining a detailed understanding of the subsurface (for example, identifying subsurface fault systems) remains a question for industry. For instance is three-dimensional seismic modelling

cost-effective and proportionate, or is high resolution two-dimensional monitoring and subsequent modelling more appropriate?

- The cumulative impacts of adjacent reinjection activities over time appear to be poorly understood in the literature reviewed.
- Has long-term fatigue damage to well casings, well heads and general infrastructure ever been linked to low level seismic activity or even noted at all?
- Is the current Eurocode 8 guidance for construction design for earthquake resistance implemented in England? And is it sufficient to protect for potential induced (or natural) seismic activity in the future?
- Hydrocarbons in the ground exist under a pressure simplistically determined by the difference between the vertical stress in the rock mass and the overburden pressure. For reinjection activities it is therefore necessary to determine the relative magnitude of the principal stresses, governed by the faulting regime. The actual values are reportedly difficult to obtain accurately. Oil and gas operators should be consulted on how they calculate the actual values or relative magnitude.

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List of abbreviations

API	American Petroleum Institute
BAT	best available techniques
BEIS	Department of Business Energy and Industrial Strategy
BGS	British Geological Survey
BSOR	The Borehole Sites and Operations Regulations 1995
DCR	The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996
DECC	Department of Energy and Climate Change
EIA	environmental impact assessment
EMS	European Macroseismic Scale
EOR	enhanced oil recovery
FDP	field development plan
HFP	hydraulic fracture plan
HSE	Health and Safety Executive
M	magnitude
NORM	naturally occurring radioactive materials
OGA	Oil and Gas Authority
PAM	polyacrylamide
PEDL	petroleum exploration and development licence
PWRI	produced water reinjection
SPZ	source protection zone
UKOOG	United Kingdom Oil and Gas

Appendix A: Information obtained from the literature review[4]

A.1 Onshore oil and gas industry in England

A.1.1 Background

This section provides high level background data on the onshore oil and gas industry within England and detailed information on the current techniques used to manage reinjection activities associated with onshore oil and gas.

Although specific to England, much of the data available for the onshore oil and gas industry are provided for the whole of the UK. Where it has not been possible to distinguish between data for England and the rest of the UK, this is stated.

The first known onshore oil and gas industry was located in the Midland Valley in Scotland in 1850. Since then, approximately 2,100 wells have been drilled in the UK (UKOOG 2015a), primarily for the exploitation of conventional oil and gas.

Shale gas production is not yet underway in England. However, coal mine methane and coal bed methane are growing industries, with around 20 wells currently active in England (DECC 2016a).

A summary of the onshore oil and gas wells drilled to date is given in Table A.1. It was not possible to determine how many of the wells are currently active, although anecdotal evidence from the Environment Agency suggests up to 143.

Table A.1 Hydrocarbon wells drilled within England since 1902

Industry	Number of wells[1]	Number of wells as a percentage of total
Conventional oil and gas	1930	94.9
Coal bed methane	54	2.7
Mine gas	39	1.9
Shale gas	7	0.3
TOTAL	**2,033**	

Notes: [1] As of December 2014. Given the evolving nature of the industry, this number may increase rapidly.
Source: DECC (2016a)

The major types of oil and gas industry that are currently underway, or are anticipated to be significant in England are in order of significance:

1. Conventional oil and gas

[4] The information presented is correct as at November 2016

2. Shale gas (and to a lesser extent oil)
3. Coal bed methane
4. Coal mine methane

Of these, only conventional oil and gas and shale gas rely on a form of reinjection or injection process to either produce or maintain/improve production from hydrocarbon reservoirs.

The work carried out for this report focuses on reinjection activities associated with conventional oil and gas activities. The injection process for shale gas is described briefly in Section A.2.2 for completeness, with case studies included where relevant.

A.1.2 Legislation and guidance

The onshore oil and gas industry is regulated by a number of statutory bodies. Among the statutory bodies listed by UKOOG (2015a) are:

- Department of Energy and Climate Change (DECC)[5]
- Minerals Planning Authorities (country councils or unitary authorities)
- Environment Agency
- HSE

The Oil and Gas Authority, established in 2015 as an executive agency of the Department for Business, Energy and Industrial Strategy, plays a major role in regulating the UK oil and gas industry and also seeks to achieve the objective of maximising the economic recovery of the UK's oil and gas resources..

The Coal Authority also needs to be consulted for sites that fall within its area of jurisdiction or ownership. The British Geological Survey (BGS) also requires notification of the commencement of drilling.

Details of legislation relevant to reinjection in onshore oil and gas operations and associated risks to groundwater resources in place at the time of writing are provided in Table A.2.

For a detailed description of the legislation for onshore hydrocarbon exploration, readers are referred to the government's regulatory roadmap for onshore oil and gas exploration (DECC 2013). The production phase is likely to require further permits or permit variations to exploration permits, but these will generally be specific to a site.

Table A.2 Key legislation and guidance relevant to reinjection and risks from seismicity in onshore oil and gas

Legislation	Context in relation to reinjection activities from onshore oil and gas
EU directives[1]	
Water Framework Directive (2000/60/EC) (WFD)	Intended to: • prevent deterioration and achieve good status for all water bodies • reduce pollution from priority substances in surface waters

[5] Now part of the Department of Business Energy and Industrial Strategy (BEIS)

Legislation	Context in relation to reinjection activities from onshore oil and gas
	• reverse significant and sustained upward trends in concentrations of pollutants in groundwater • prevent or limit inputs of pollutants to groundwater
Groundwater Daughter Directive (2006/118/EC)	Provides further requirements to protect groundwater to deliver the overall objectives of the WFD. Requires Member States to put in place processes to deliver these objectives.
Environmental Quality Standards Directive (2008/105/EC) (EQSD)	Implements provisions within the WFD for environmental quality standards for priority substances and other pollutants with the aim of achieving good water chemical status.
The Environmental Impact Assessment Directive (85/337/EC) (EIA)	Hydrocarbon exploration and production projects fall under this directive, although EIA is only mandatory in certain circumstances. Outlines the EIA requirements and states that operators cannot commence work without a permit.
Basic Safety Standards Directive (96/29/Euratom) (BSSD)	Lays down basic safety standards for the protection of the health of workers and the general public against the dangers arising from ionising radiation. It sets out the principles of justification, optimisation and dose limits for practices.
UK legislation	
Petroleum Act 1998	Regulates rights to onshore and offshore UK oil and gas resources. Lays down provisions to regulate oil and gas exploration and production licence applications. Amended in 2015 to include safeguards regarding onshore hydraulic fracturing from the Infrastructure Act 2015.
Infrastructure Act 2015	Regulates hydraulic fracturing operations to limit risk to groundwater resources including via fracture propagation and induced seismicity.
Environmental Permitting (England and Wales) Regulations 2010 (EPR 2010)	Extend to England and Wales only. Bring the following EU directives into UK law: • Industrial Emissions Directive • Mining Waste Directive • Revised Waste Framework Directive • Water Framework Directive • Groundwater Daughter Directive • Environmental Quality Standards Directive (indirectly) • BSSD The regime covers facilities previously regulated under the Pollution Prevention and Control Regulations 2000,

Legislation	Context in relation to reinjection activities from onshore oil and gas
	and Waste Management Licensing and exemptions schemes (as superseded by the Environmental Permitting (England and Wales) Regulations 2007), some parts of the Water Resources Act 1991, the Radioactive Substances Act 1993 and the Groundwater Regulations 2009. Regulates activities relevant to onshore oil and gas including: • mining waste operations • water discharge activities • radioactive substances activities • groundwater activities
Town and Country Planning Act 1990	Concerns land use planning. Its goal is to ensure sustainable economic development and a better environment. Planning permission is required for all hydrocarbon developments. States that planning permission for onshore oil and gas sites must be obtained from the relevant minerals planning authority.
UK guidance	
Groundwater Protection: Principles and Practice (GP3) (Environment Agency 2013)	Outlines the approach towards management and protection of groundwater in England and Wales. States how the 'permanently unsuitable'[2] designation is determined – required in some cases for permits to carry out reinjection to be issued.
Onshore Oil and Gas Sector Guidance (Consultation draft – November 2015) (Environment Agency 2015)	Outlines what onshore oil and gas operators in the UK need to do to comply with existing legislation in terms of required permits and best available techniques (BAT). Includes specific guidance referring to reinjection activities (see Figure A.1 and associated text below).
Planning Practice Guidance for Onshore Oil and Gas (DCLG 2013)	Outlines the responsibilities of different regulatory bodies in the planning application process for oil and gas operations.
UK Onshore Shale Gas Well Guidelines (UK00G 2015)	Guidelines produced by UK Onshore Oil and Gas (UKOOG) to advise on meeting regulatory requirements during the exploration and appraisal phases of shale gas developments. Includes recommendations on assessing the risks from induced seismicity.
Strategy for the Management of Naturally Occurring Radioactive Material (NORM) Waste in	Provides guidance for the whole of the UK non-nuclear industries, including aspects of onshore and offshore oil and gas industries in the UK.

Legislation	Context in relation to reinjection activities from onshore oil and gas
the United Kingdom (DECC 2014)	

Notes: [1] Shortened titles are used
[2] The term 'which for natural reasons are permanently unsuitable for other purposes' is defined in Article 11.3j of the Water Framework Directive.

There is limited existing UK guidance that deals specifically with reinjection activities and potentially associated geomechanical impacts in conventional operations. The Onshore Oil and Gas Sector Guidance was released in draft for consultation in November 2015 (Environment Agency 2015). This document outlines the Environment Agency's approach to the permitting of reinjection activities in onshore oil and gas operations. The approach to permitting varies according to:

- whether the reinjection is to facilitate production or to dispose of waste water
- whether the reinjection is occurring at the same site as the extraction or at a different site (or within the same or different formation)

The flow chart shown in Figure A.1 summarises the Environment Agency's approach to reinjection of produced water generated from onshore oil and gas activities. This method is not applicable to flowback fluids from shale gas activities as they are not permitted to be reinjected other than for reuse during fracking events. Please refer to the sector guidance document for further details and the separate approach used by the Environment Agency) (Environment Agency 2015, pp. 40-41).

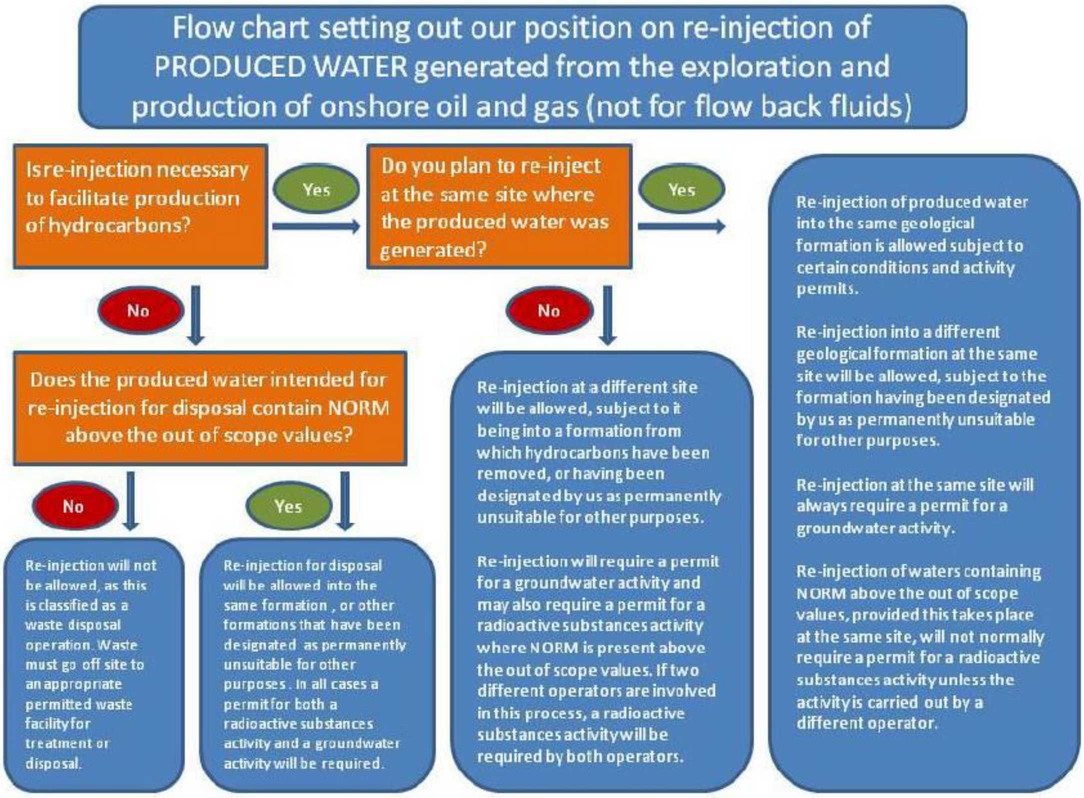

Figure A.1 Environment Agency's draft approach to reinjection of produced water

Source: Environment Agency (2015, Figure 2)

UK guidance that relates specifically to induced seismicity is limited to operations where hydraulic fracturing is taking place, with no guidance currently available in England for conventional operations. In terms of conventional operations, the minerals planning authority considers issues of land stability and subsidence in the planning process (DCLG 2013). Consideration of risks from seismicity may be considered by DECC [BEIS] through the licence consent regime (DCLG 2013). Any concerns about risks to groundwater resources from reinjection activities would be considered by the Environment Agency at the permitting stage.

Design of structures for earthquake resistance

There is limited guidance on the design of structures related to oil and gas operations in the UK. The most relevant guidance available is Eurocode 8, Part 4 on the design of structures for earthquake resistance for silos, tanks and pipelines (CEN 2006).

The general guidelines for designing a buried pipeline system are summarised below. The seismic design of a buried pipeline system should take into account the following direct and indirect seismic hazards:

- seismic waves propagating on firm ground producing ground shaking and spatial soil deformation patterns
- permanent deformations induced by earthquakes (for example, seismic fault displacements, landslides and ground displacements)

The guidance states that the general requirements for the states of damage limitation and ultimate limit (see Table A.3) must be satisfied for these hazard types.

It is accepted that it is not always feasible to avoid crossing potentially active faults, soils susceptible to liquefaction, areas affected by landslides or permanent ground deformations. In such cases, reasoned assumptions should be used to define the model for the hazard, based on available data and experience.

Table A.3 Definitions of 'ultimate limit state' and 'damage limit state' according to EU guidance (Eurocode 8, Part 4)

State	Definition
Ultimate limit	The ultimate limit state for which a system must be checked is defined as that corresponding to structural failure. In some circumstances, partial recovery of the operational capacity of the system lost by exceedance of the ultimate state may be possible after an acceptable amount of repairs. NB The circumstances are those defined by the responsible authority or client.
Damage limitation	Depending on the characteristics and purpose of the structure, the damage limitation state may need to meet one or both of the following performance levels: • Integrity – where the system must remain fully serviceable and leak proof under the relevant seismic action • Minimum operating level – the extent and amount of damage to the system must be limited so that, after the operations for damage checking and control are carried out, the capacity of

State	Definition
	the system can be restored up to a predefined level of operation The seismic action for which the limit state may not be exceeded should have an annual probability of exceedance whose value is to be established based on the following: • the consequences of loss of function and/or of leakage of the content • the losses related to reduced capacity of the system and to the necessary repairs

Source: CEN (2006)

These guidelines are not country specific and are therefore quite limited in their application.

There are no specific guidelines on the magnitude of earthquakes that support infrastructure (for example, pipelines and tanks) should be able to withstand. While the UK is not prone to experiencing large magnitude earthquakes (for example, greater than M3), induced seismicity from reinjection activities may result in earthquakes with a similar magnitude of the more commonly recorded low magnitude earthquakes (for example, M1 to M2). Induced seismic magnitudes of greater than M3 are considered unlikely in England for conventional operations as detailed below.

A.1.3 Mitigation and monitoring measures in England

Conventional oil and gas

As previously stated, there is no existing UK guidance with specific recommendations for monitoring requirements during reinjection as part of conventional oil and gas activities. However, there are a number of technical considerations that an oil and gas operator will need to assess as part of an effective produced water reinjection (PWRI) strategy. These aspects are discussed in greater detail in the following sections but may include:

- continuous pressure monitoring
- injectivity and falloff testing
- potential use of observation wells (including microseismic monitoring and tilt meters)
- monitoring of a variety of mechanical components
- established responses for pressure build-up
- established responses where confinement problems are identified (that is, unwanted fracturing leading to loss of containment/pressure or issues with well integrity)

Injectivity and falloff testing are conducted by the operator prior to full-scale injection and are typically used by rock mechanics and reservoir engineers to determine injection pressures, pumpable volumes and well bore skin factors, as well as a full range of other parameters relevant to oil field engineers. In terms of volumes of fluids used for such testing, these are relatively much smaller than the volumes used for reinjection or high volume, high pressure hydraulic fracturing.

Operators in England may rely on the above methods to different extents, with some of these approaches only undertaken and reviewed periodically (for example, injectivity and falloff testing). Other methods, such as mechanical component monitoring, may be performed more regularly, with certain monitoring procedures potentially carried out on a day to day basis as part of well examination schemes that monitor well integrity throughout the operational life span of the well.

HSE may receive information on these aspects, particularly injectivity and falloff testing, within an operator's well notification (that is, notification of an activity prior to drilling a well or undertaking any other modification works on a well). While injection pressures will always be monitored by the operator, they may not always be recorded (HSE, personal communication, 2016).

All onshore operators are expected to adhere to preventative maintenance standards. For example, injection fluids need to be:

- monitored and de-aerated to avoid corrosion of casing and tubing
- free from bacteria to prevent creation of hydrogen sulphide
- free of any chemicals that might react with salts in the geological formation forming unwanted scale or solid content outside acceptable limits

Importantly, seismic activity resulting from reinjection would not be reportable to HSE unless there was an impact on the pressure-containing envelope of the well. Reinjection may be broadly viewed by HSE as a preventative measure of seismic activity by maintaining pressure in the reservoir and therefore preventing compaction and subsidence in the cap rock formations (HSE, personal communication, 2016).

There is no industry-wide approach to established responses to pressure build-up and confinement problems. However, it is understood that each operator is likely to have developed their own response specific to their operations.

The above list represents approaches to enable an effective PWRI strategy to be implemented. However, it is broadly considered within the industry (webinar, 2016) that these approaches may also inadvertently limit the potential for unwanted geomechanical impacts to occur (for example, induced seismicity and unwanted fracture propagation).

Unconventional oil and gas

Existing UK guidance provides recommendations for monitoring and mitigation measures to reduce risks from induced seismicity for unconventional operations only, namely shale gas. The Oil and Gas Authority (OGA) is responsible for ensuring controls are in place by the operator to monitor and mitigate seismic risks through a hydraulic fracture plan (HFP).

Following the recorded seismicity at Preese Hall (Green et al. 2012), DECC introduced new controls on operators planning to carry out hydraulic fracturing (DECC 2014). These are summarised below.

If hydraulic stimulation is proposed as part of the extended well test, an HFP must also be agreed with the OGA in consultation with the Environment Agency. OGA requirements may include:

- a map and seismic lines showing faults near the well and along the well path, with a summary assessment of faulting and formation stresses in the area and the risk that the operations could reactivate existing faults
- information on the local background seismicity and an assessment of the risk of induced seismicity
- a comparison of proposed activity with any previous operations and any relationship to historical seismicity
- a summary of the planned operations, including the techniques to be used, the location of monitoring points, stages, pumping pressures, volumes and the predicted extent of each proposed fracturing event
- proposed measures to mitigate the risk of inducing an earthquake and a description of a decision tree for a real-time traffic light scheme for monitoring local seismicity
- the processes and procedures that will be put in place during hydraulic fracturing for fracture height monitoring to identify where the fractures are within the target formation and to ensure they are not near the permitted boundary
- in the event that the fractures extend beyond the Environment Agency permit boundary, the steps that would be taken to assess and if necessary mitigate the effect and limit further propagation outside the target rocks
- the type and duration of monitoring and reporting during and/or after hydraulic fracturing and the geological data to be published
- the procedure for post fracturing reporting of the location, orientation and extent of the induced fractures to demonstrate that the Environment Agency permit has been complied with – including provision for reporting on proposed mitigation measures to prevent propagation should fractures extend to within a short distance of the permitted boundary
- the proposed level of seismic event above which fracturing cannot resume without consent after evidence is provided that the wells are not damaged and the groundwater remains protected

Less information may be required for a small volume hydraulic stimulation of a conventional target.

Demonstration that these controls will be put in place is through the submission of the HFP by the operator to the Oil and Gas Authority, which must approve it in consultation with the Environment Agency before granting consent for operations.

A 'traffic light system' (Table A.4) is used during fracturing operations and determines whether it is safe to proceed with the injection. The system is applied to the first set of hydraulic fractures and is subject to review (DECC 2015).

A 0.5 ML (local magnitude) earthquake is a red light. A 0.5 ML event is not cause for concern and is unlikely to be perceptible, but analysis of the Lancashire data indicates that such an event may be an indication of, or precursor to, a larger earthquake.

Table A.4 Seismic monitoring traffic light system[1]

Colour	Magnitude on the Richter scale	Is it safe to proceed with injection of water?

Green	<0	Injection proceeds as planned.
Amber	0–0.5	Injection proceeds with caution, possibly at reduced rates. Monitoring is intensified.
Red	≥0.5	Injection is suspended immediately and pressures immediately reduced. Operator must monitor for 24 hours after a magnitude 0.5 event to determine if a later ‘felt’ event is recorded.

Notes: [1] The regulations on seismic monitoring ensure that seismic activity during fracking operations is monitored to allow action to be taken where necessary.
Source: DECC (2014, p. 3)

The magnitude 0.5 threshold was determined by an independent report commissioned following the events at Preese Hall (Green et al. 2012).

The traffic light system is only required for hydraulic fracturing operations and is not required for conventional operations.

A.1.4 Mitigation and monitoring of reinjection activities in other countries

The USA and Canada represent oil producing countries with well-established onshore conventional industries with a number of incidents that allow a review of case history. Table A.5 presents a comparative summary of guidance for mitigation and monitoring for onshore oil and gas operations for reinjection activities and geomechanical impacts in England, the USA and Canada.

Guidance on monitoring and mitigation for onshore reinjection oil and gas activities in the UK is generally limited to unconventional practices.

Table A.5 Comparison of guidance for mitigation and monitoring for oil and gas operations in England, USA and Canada

Country	Guidance for mitigation and monitoring of reinjection activities	
	Conventional oil and gas	Unconventional oil and gas
England	No current guidance	Fracking UK shale: understanding earthquake risk (DECC 2014)
USA	API Recommended Practice 51R. Environmental Protection for Onshore Oil and Gas Production Operations and Leases (API 2009)	API Recommended Practice 100-1 – Hydraulic Fracturing – Well Integrity and Fracture Containment (API 2015)
Canada[1]	Limited guidance on monitoring and mitigation for conventional operations and specifically for reinjection activities in most states and provinces	Significant guidance on monitoring and mitigation for unconventional operations in most of states and provinces

Notes: [1] Each province and federal state in Canada has its own regulations and regulators.

US guidance

US guidance on mitigation and monitoring in conventional reinjection activities can be found in 'Environmental Protection for Onshore Oil and Gas Production Operations and Leases' (API 2009). The guidance provided is high level without providing any specific details or criteria. Key areas of the guidance relevant for this study are summarised below.

Section 6.1.4 of the guidance provides a brief overview of injection and disposal well considerations. This includes:

- ensuring that injected fluids enter the desired formations and do not enter other formations or drinking water zones
- reviewing the area around the injection well to assess if any other wells (active, inactive or abandoned) were drilled through the injection/disposal zone

Section 6.1.5 refers to remedial cementing and suggests that the known and anticipated needs for remedial cementing to protect underground sources of drinking water should be considered at the planning stages.

Section 6.2.3 discusses leak prevention where all equipment should be inspected on a routine basis for signs of leakage. Corrective action must be taken where leaks are detected to assure the equipment continues to operate in a safe and environmentally acceptable manner. It further states that all injection and disposal wells equipped with tubing and packed should be periodically monitored.

- Tubing casing should monitor annulus pressure to test integrity of the tubing and packer.
- Where no packer is installed, other methods should be used such as tracer logs or temperature logs to ensure that the fluids injected are properly controlled and going into the proper injection/disposal formations.

The frequency of these tests is dependent on the operating conditions, with areas prone to corrosion being undertaken more frequently.

Section 6.4.2.2 discusses the purpose of plugging wells and highlights the importance of preventing inter-zonal migration of fluids such as the contamination of aquifers, surface soils and surface waters as well as conserving hydrocarbon resources. This section also discusses the need to consider other local wells either active or abandoned as these can also act as a conduit if not properly plugged.

Section 8.5.4 discusses corrosion monitoring and treatment. Monitoring should be considered if produced fluids are suspected of being corrosive. If produced fluids are determined to be corrosive, a corrosion abatement programme should be considered.

International

For all 3 countries, there is far more extensive guidance for unconventional oil and gas operations compared with conventional. However, the International Association of Oil & Gas Producers (IOGP)[6] provides international guidelines into process monitoring and

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[6] Formerly known as OGP

control for reinjection activities in conventional oil and gas operations (OGP 2000). The guidance recognises that the extent to which regulatory authorities in different countries require monitoring and control varies considerably.

The monitoring and control practices detailed in the guidance fall under the following headings:

- produced water injection data
- produced water quality in relation to injectivity and operations
- well design and construction
- containment and confinement
- continuous pressure monitoring
- process monitoring and control
- operational issues
- injection well abandonment

Produced water injection data

This section of the IOGP guidance highlights important factual information required to design an effective PWRI project. This includes:

- general information on the location of the sites
- proximity to other fields and disposal wells
- proximity to environmental receptors

It also requests specific information for a range of aspects including:

- geology and hydrogeology
- the geohydrogeological and geomechanical properties of the injection and confinement layers
- the in situ stress profile in the various layers

Produced water quality in relation to injectivity and operations

This section of the IOGP guidance discusses the information required to help:

- define or predict the potential for scale formation (similar to the formation of limescale in domestic kettles)
- assess the potential permeability degradation that may result from an incompatibility among the injected water, connate water and injection/confinement zone lithologies (for example, adverse rock/fluid interactions)

Such outcomes may result in a loss of injectivity where the formation becomes plugged around the injection well. These outcomes may have limited geomechanical implications, but are likely to result in unacceptable operational issues. Produced water treatment is a crucial process in managing these potential issues, but is primarily focused on ensuring operational optimisation rather than environmental compliance.

Well design and construction

The design and construction of wells and their long-term integrity is of critical importance to the objectives of this report as release of contamination from wells is considered one of the more viable mechanisms of potentially contaminating groundwater.

From an operational perspective, the IOGP guidance notes that the design and construction of a reinjection well are important factors in achieving the objectives of a PWRI project. Pressure, fluid composition, duration and so on all depend on the well's integrity and therefore on its design and construction.

The IOGP guidance suggests that well design should be checked against the anticipated loads during reinjection and later in its life after corrosion and erosion may have degraded the well. However, the guidance does not consider the potential of geomechanical impacts such as induced seismicity. This may be potentially due to the general absence of any substantial evidence that reinjection at low pressures in conventional fields results in unwanted or potentially damaging seismicity, and therefore does not warrant focus on these matters.

In England, drilling can only commence once:

- HSE has been provided with details of the proposed well design
- the design has been examined by an independent and competent well examiner

Operators also need to:

- adhere to an agreed well examination scheme
- agree with HSE on contingency plans within their field management plans that are considerate of the well during operations

Containment and confinement

A well designed and implemented PWRI strategy will focus on ensuring that reinjected produced waters are contained within acceptable injection zones away from any groundwater sources or other potential environment receptor. The IOGP guidance highlights the general approaches to ensure that this is managed including the crucial information and modelling required to assist operators in achieving this key objective.

Process monitoring and control

This section of the IOGP guidance considers the following process monitoring and control aspects:

- continuous pressure monitoring
- observation wells
- mechanical components

Continuous pressure monitoring enables operators to manage injectivity by aiming to achieve a constant pressure within the reinjection wells (in essence a balancing of the reservoir pressure).

The Hall plot shown in Figure A.2 provides a useful representation of how deviation from the ideal modelled pressure could suggest issues that may warrant remedial action. It highlights:

- a loss of injectivity – which may result in damage to the well or associated infrastructure

- loss of containment – which may indicate the creating of unwanted fractures or fracture propagation

The collection of sufficient information to enable this kind of understanding is required if an acceptable pressure monitoring programme is to be established.

Where observation wells are available, the IOGP guidance suggests that these can be used to carry out microseismic monitoring as well as the potential placement of downhole tilt meters which can provide information on fracture growth. Pressure and fluid samples from the monitoring well can provide information on fluid flows.

The number of observations wells in England is not known, but some important operators are known to use them for monitoring reservoir pressures. No operator is known to use these for monitoring seismic activity.

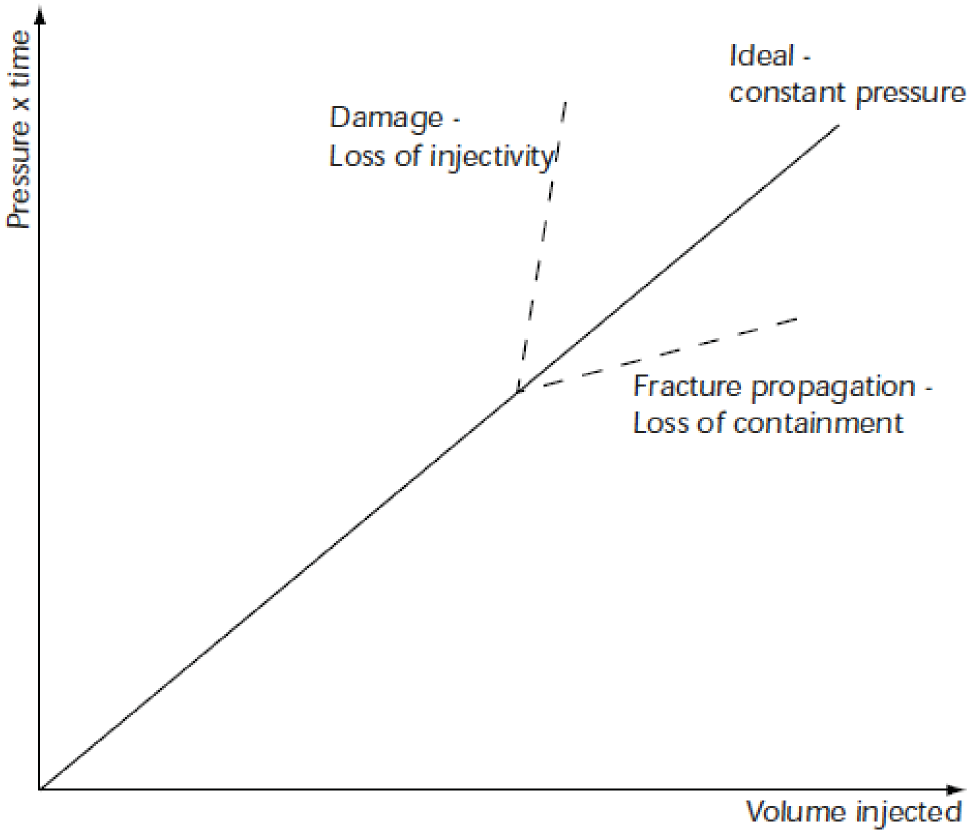

Figure A.2 Hall plot demonstrating potential pressure and volume relationships when assessing injectivity

Source: OGP (2000, Figure 2))

Monitoring of mechanical components is used to monitor the mechanical integrity of the reinjection well or annulus. Compromises to the mechanical integrity of the borehole include leaks in tubing, casing or packer, and flow behind the casing. The following methods are considered within the IOGP guidance:

- annulus pressure monitoring
- pressure testing
- temperature logging
- noise logging

- pipe analysis survey
- electromagnetic thickness survey
- caliper log
- borehole televiewing
- flowmeter survey
- radioactive tracer survey
- oxygen activation logging
- cement bond logging

The extent to which mechanical component monitoring is implemented in England is not well known. From discussions held during the UKOOG webinar on the 24 February 2016, however, it is expected that most operators undertake some level of mechanical monitoring on a daily basis as part of the commitments in their well examination scheme and a drive to ensure optimal operation of their wells over their life time.

A.1.5 Reinjection activities

Current

Onshore oil and gas production is a well-established industry in England with hydrocarbon wells being drilled as early as 1902 (DECC 2016a). A summary of conventional oil and gas reserves in England of, location, resource, geology and reservoir type is presented in Table A.6.

Information on the reinjection of produced waters at operating conventional fields in England is limited with very little to no information on the reinjection pressures. There is also limited to no evidence of any notable seismic activity being associated with reinjection activities on conventional oil fields in England. The only notable seismic event linked to oil and gas activities in England appears to be related to recent shale gas operations where a hydraulic fracture technique is implemented (that is, Preese Hall).

England's onshore conventional oil developments are typically limited to small oil plays, each with limited production wells and in many cases with just singular well pads in place. However, one important area where significant conventional reinjection activities take place, including the reinjection of produced water and make-up waters such as sea water and surface run-off, is the Wytch Farm field in Dorset. This produces from sandstone and limestone formations between 750 and 1600m below ground level. This operation has been active since the 1960s, with current reinjection activities performed to enhance production (Hogg et al. 1999) and is the only enhanced oil recovery (EOR) operation in England. The reinjection takes place into the producing stratum, with no geomechanical impacts associated with PWRI having been reported over its operational lifetime.

The injection of fluids for shale gas operations has taken place at an exploration level only and at only one location – Preese Hall, in the north-west of England. Fracture fluid was injected into the Bowland Shale Formation of Carboniferous age at bottom hole pressures up to 60MPa over short durations, typically 2–3 hours introducing up to 2,500m^3 of fluid into the reservoir (de Pater and Baisch 2011). This injection event did result in induced seismic activity (2 notable seismic tremors), with recommendations made for mitigating such outcomes detailed in a report on the events commissioned by DECC from independent consultants (Green et al. 2012).

Table A.6 Summary of the main hydrocarbon reservoir characteristics onshore UK

Province	Typical hydro-carbon occur-rence	Typical Reservoirs	Source(s)	Trap type	Examples
Wessex-Channel Basin	Oil and gas	Bridport Sands, Great Oolite (Jurassic), Sherwood Sandstone Group (Triassic)	Lower Lias (clays Jurassic)	Tilted fault blocks & Palaeogene inversion anti-clines	Oil: Wytch Farm, Kimmeridge, Humbly Grove, Stockbridge, Wareham Gas: Albury
East Mid-lands	Oil and gas	Silesian sand-stones & frac-tured Dinantian limestones (Carboniferous)	Silesian (Carbon-iferous) mud-stones and coals	Variscan anticlines and stratigraphic traps	Oil: Eakring, Welton, Remp-stone, Scamp-ton, Gains-borough Gas: Hatfield Moors and Hatfield West, Trumfleet, Saltfleetby
Yorkshire/NE England	Gas	Permian limestones (e.g.Upper Magnesian Limestones)	Silesian (Carbon-iferous) mud-stones and coal	Mesozoic folds	Malton, Mar-ishes, Lockton, Eskdale
NW England	Oil and gas	Sherwood Sandstone Group (Triassic)	Silesian (Carbon-iferous) mud-stones and coals	Variscan anticlines, Stratigraphic – superficial deposits trap-ping oil	Oil: Formby Gas: Elswick
Midland Valley Scotland	Oil and gas	Silesian sand-stones (Carboniferous)	Silesian (Carbon-iferous) mud-stones and coals	Variscan anti-clines	Oil: Dalkeith, Gas: Cousland

Notes: Trap type is the geological structure which contains hydrocarbon system (that is, source and reservoir).

Source: BGS (2011, Table 1)

Future trends

The conventional onshore oil and gas industry in England is generally in decline. No major sources of onshore hydrocarbon similar to Wytch Farm have been discovered in recent times, resulting in an overall trend of maturation of existing oil fields.

Production at Wytch Farm, the largest onshore oilfield in western Europe, has reduced to approximately 15,000 barrels per day from a peak of almost 100,000 barrels per day in 1996. The Wytch Farm site has been consistently responsible for 85–90% of onshore oil production in England over the past 20 years (Figure A.3).

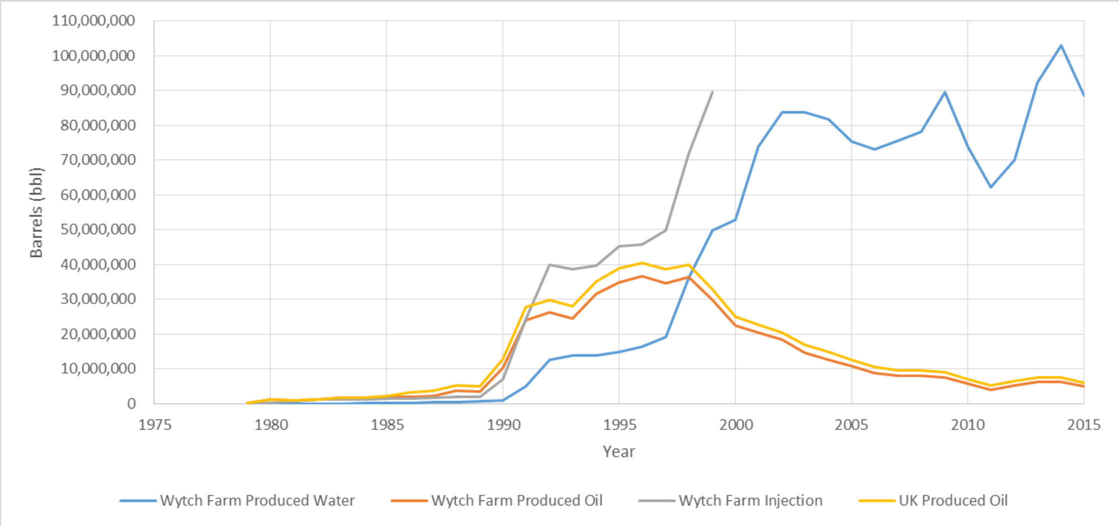

Figure A.3 Onshore oil production showing Wytch Farm contribution to UK oil production, and volumes of injection and produced water

Source: DECC (2016b)

As total production at the onshore oil fields is in decline, it might be reasonably expected that total reinjection volumes will increase. This is as a result of trying to extract the maximum hydrocarbon potential from the reservoir and also injection activities associated with the disposal of excess produced water, of which approximately 250,000 barrels per day is estimated to be being produced in Great Britain (UKOOG 2013).

Following the completion of the 14th Petroleum Exploration and Development Licence (PEDL) licensing round, a number of new blocks have been awarded PEDLs for further exploration and development. Many of these are likely to be characterised by new, relatively small fields (compared with Wytch Farm) being explored and potentially developed over the coming years. While these will potentially result in new conventional developments with some local reinjection activity, these are most likely to be on a considerably smaller scale than Wytch Farm and collectively still only form a small part of the overall reinjection volumes likely to be occurring in England (that is, the majority still being carried out at Wytch Farm) over the coming years.

Reinjection of produced water from conventional activities for disposal purposes is one area where there is little consensus or even general knowledge of potential future trends. It is understood that there are a small number of sites that dispose of produced water to producing formations, but limited knowledge on those sites disposing of produced waters to non-producing formations identified as ‘permanently unsuitable’ (see Table A.2 for a definition). Communications with the Environment Agency as part of this study suggest that potentially at least one site in south-east England disposes of produced water to a non-productive formation, although this may have been regulated prior to the implementation of the Groundwater Directive and may not have been considered against the ‘permanently unsuitable’ criteria.

From the available information reviewed, it appears that disposal to non-producing formations is not commonly utilised in England. One of the reasons for this cited by industry (webinar, 24 February 2016) is that there are concerns that disposal of produced waters to a formation deemed permanently unsuitable, which has not been subject to oil and gas production and where robust monitoring and mitigation is not undertaken, may present a greater risk of geomechanical impacts. This perspective is broadly consistent with the general observation that, in the USA, much of the induced seismic activity recorded in recent times is more likely to be associated with disposal well activities than hydraulic fracturing.

General industry opinion suggests that disposal of produced water to non-producing formations does not represent an attractive option for conventional activities and is likely to be utilised infrequently over the coming years.

While not the focus of this report, it is noted that the hydraulic fracture type injection activity for the exploitation of shale gas may well see a marked increase over the coming years – depending on global oil prices and other political considerations. The potential risk of increased induced seismic activity and other geomechanical impacts may follow if suitable mitigation and monitoring methods are not employed.

Various studies carried out in England have indicated that significant quantities of hydrocarbons exist in England, particularly in the Weald Basin (south-east England) and in a band running roughly north-east to south-west between Scarborough and Chester (Figure A.4). These areas are the ones most likely to see an increase in unconventional sources of oil and gas being explored and developed.

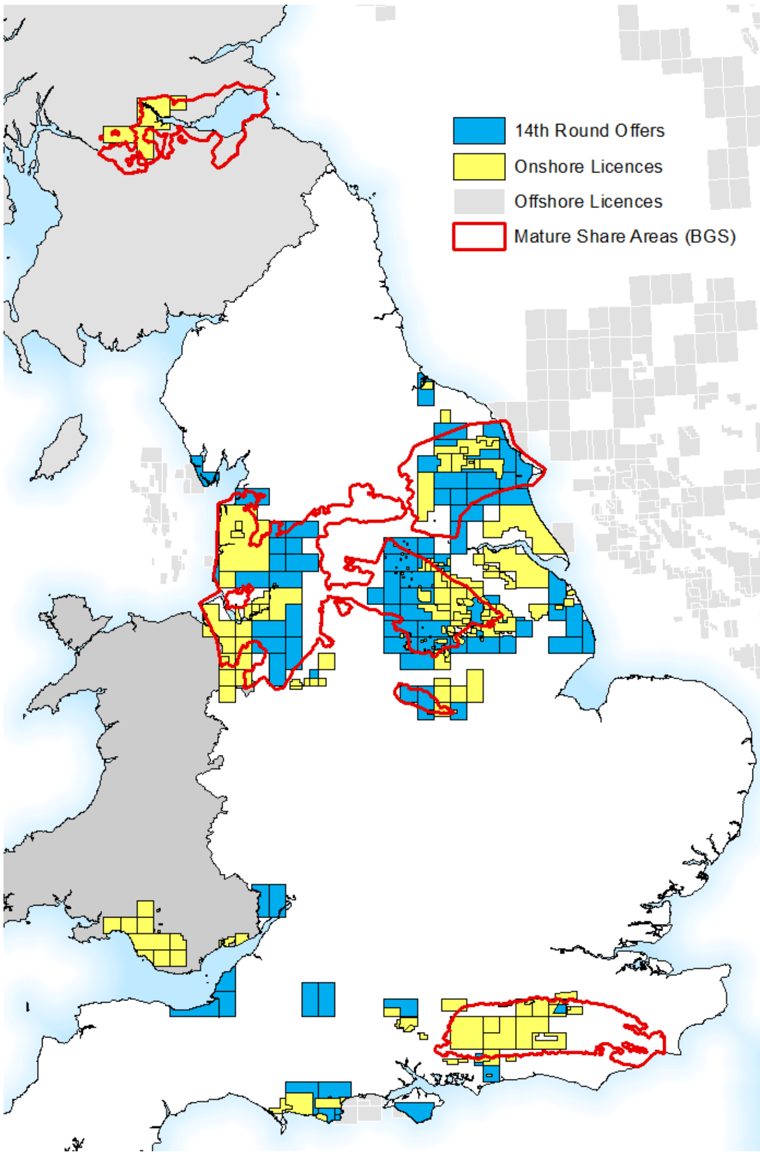

Figure A.4 Location of onshore oil and gas licences in Great Britain, with shale gas regions outlined in red

Source: DECC (2016a)

When considering the siting of conventional and unconventional sites, operators and regulators will need to be mindful of the potential for cumulative impacts, including those arising from geomechanical disturbance, should shale gas activities be located close to conventional ones. At present there is no clear information to suggest how this will look going forward or what potential cumulative impacts could occur in such instances.

A.1.6 Potential risks to groundwater receptors

The Environment Agency has statutory responsibility to protect groundwater resources in England. Groundwater Protection: Principles and Practice (GP3) provides a framework to allow the Environment Agency to achieve this (Environment Agency 2013) and works alongside defined Groundwater Source Protection Zones (SPZs)[7] to identify and protect sensitive groundwater resources.

SPZs are a crucial regulatory tool for protecting abstraction sources used for drinking water or food production. SPZs are defined by the time it would take for pollutants to travel from the edge of a zone to a source of drinking water. An SPZ 1 covers the area within a 50 day groundwater travel time of the source and extends a minimum of 50m from a drinking water borehole. The zone represents the immediate area around a borehole where remediation of pollution is expected to be unachievable within 50 days. An SPZ 2 zone covers the area within a 400 day travel time and a minimum of 250m radius from the borehole, while an SPZ 3 covers the total source catchment.

Before commencing a groundwater activity in England for onshore oil and gas operations, operators must ensure that:

- they can demonstrate to the Environment Agency how BAT will be applied to protect groundwater
- they can demonstrate that their activity will not cause pollution to groundwater
- activities are not within a SPZ1

In considering the management and protection of groundwater resources, a number of aspects should be considered by operators including:

- consideration of geology and hydrogeology
- depth, location and sensitivity of groundwater resources
- faults and fracture systems within the different geological units in the area of exploration and/or production (with focus on presence of any cross-cutting faults or fractures)
- details of the containment and confinement layers including an understanding of the stress profiles, and the geomechanical and hydrogeological aspects of all formations

Interaction between oil and gas activities and groundwater

A review of the relationship between well locations in relation to environmentally protected groundwater receptors found that the majority of wells were located within these protected areas (Davies et al. 2014). However, under the Groundwater Daughter

[7] See http://apps.environment-agency.gov.uk/wiyby/37833.aspx

Directive, all groundwater in England would be deemed environmentally protected unless determined as permanently unsuitable and so such a comparison is not necessarily appropriate in the context of this report. A more appropriate appraisal consideration of the objectives of this report would have been to review all oil and gas wells in proximity to SPZs as it is these that provide material restrictions on groundwater activities.

A full appraisal of all wells in England in close proximity to (the more relevant) SPZs is not included in this report, but would be a material consideration by operators at the time of licensing (that is, PEDL) and during the well design and construction phase. Good well design, construction and ongoing maintenance processes (that is, well examination scheme and field management plans as regulated by HSE) should minimise the potential risks of leakages to groundwater and can therefore be proactively managed. No case studies of groundwater contamination resulting from leaky wells have been identified, with no known instances of this occurring in England.

Faults and fractures

As many of the licensed areas and existing oil and gas wells in England are either close to or located within aquifers, it is important to understand the location – including the density and orientation of any known faults in the area – so as to assess the potential for direct impacts to groundwater or other sensitive environmental receptors (for example, via fluid flow to aquifer via faults or fractures). It is also important to understand the location, density and orientation of faults relative to proposed or existing wells as an induced seismic event could cause indirect impacts (for example, damage to infrastructure such as the well or surface pipelines and tanks).

The map at Figure A.4 shows the known faults in the UK. Comparison with the map at Figure A.4 gives an indication of their lateral proximity to the licensed hydrocarbon areas. Almost all the licensed areas have faulting mapped in their vicinity, but the density of this faulting can be observed to increase markedly in the north-west of England.

Rather than the lateral proximity of a fault to a well, it is the tectonic history, juxtaposition of lithology and depth profile of faults and fractures that are of critical importance. It is this relationship that determines their ability to provide a conduit between injected fluids and a groundwater resource/aquifer. Where these fault and fracture systems are well understood, especially in relation to the containment and confinement layers, adequate injectivity monitoring programmes can be maintained and proactively minimise the potential risks of slippage on faults and fractures.

Figure A.5 Location of known faults in the UK

Source: BGS (2016)

Potential groundwater contaminants

Produced water contains a variety of contaminants that could pose a risk to groundwater if a pathway were created either from depth or at the surface. The exact chemical composition of produced waters depends on the surrounding geology; typical potential chemical constituents are listed in Table A.7. The presence and/or concentrations of each will vary between sites, over time and between type of activities (for example, coal bed methane and unconventional).

Table A.3 Typical constituents of produced water[1]

Constituent	Examples	Source
Acidity	Conventional oil: pH 4.3–10 Conventional gas: pH 3.1–7.0	Igunnu and Chen (2012)
Dissolved and dispersed oil compounds and organic compounds	Benzene, toluene, xylene and ethylene (BTEX), phenols, polycyclic aromatic hydrocarbons (PAHs) and other aromatic and aliphatic compounds Free product Organic acids such as formic acid and propionic acid	Ahmadun et al. (2009)
Heavy metals	Cadmium, chromium, copper, lead, mercury, nickel, silver and zinc	Ahmadun et al. (2009)
Radioactive materials	Radium, barium sulphate Approximate concentration ranges: ^{226}Ra: 0.3–16Bq/l ^{228}Ra: 1.3–21Bq/l ^{210}Pb and decay products	Ahmadun et al. (2009), Scottish Government (2014)
Variety of anions and cations	Example cations: K^+, Ca^{2+}, Mg^{2+}, Ba^{2+}, Fe^{2+} Example anions: SO_4^{2-}, CO_3^{2-} and HCO^{3-}	Ahmadun et al. (2009)
High salinity (mostly Na^+ and Cl^-)	Salinity can be up to 300,000mg/l	Igunnu and Chen (2012)
Dissolved gases	CO_2, O_2, H_2S are commonly found in produced water	Ahmadun et al. (2009)
Suspended solids	Formation materials, precipitated solids, bacteria[2]	Igunnu and Chen (2012)

Notes: [1] This table contains only those constituents deemed to be naturally derived, rather than any contaminants that may potentially be added during the reinjection process (for example, biocides, de-scalers and oxygen scavengers).
[2] It is likely to be BAT to ensure that produced waters are free from bacteria prior to reinjection (Environment Agency, forthcoming).

Various non-hazardous additives are used to facilitate certain aspects of the drilling and production process. Similar additives and concentrations are used in both the conventional and unconventional industries. The additives listed in Table A.8 are those used to date in hydraulic fracturing fluids in the UK (Langenhoff 2011, Environment

Agency, forthcoming). The table also includes a brief overview of the main fate and transport properties of the additives.

Table A.8 Possible additives in shale gas operations

Type of hydraulic fracturing additive	Example of main constituent substances	Purpose	DT50 water (half-life)	Properties and potential for transport in groundwater
Friction reducer	Polyacrylamide (PAM)	Minimises friction between the fluid and the pipe	N/A	There is no consensus on the definition or magnitude of biodegradation, so defining a half-life is problematic and open to site-specific assessment.
Diluted acid	Hydrochloric acid	Clean up of perforations in the casing Helps dissolve minerals and initiate cracks in the rock	N/A	Dissociates rapidly into H^+ and Cl^- (not considered to pose a severe risk unless in extremely high concentrations).
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive by-products	10.6 hours (aerobic), 7.7 hours (anaerobic) (Leung 2001a)	Moderate to high potential to leach from soil (PTRL 1994) Readily biodegradable in fresh water. Prefers to remain in water in water–sediment system (Leung 2001b). Non-hazardous and not considered a risk.
	Quaternary ammonium chloride		Half-lives in water and soil may be in the range: Water: 15–37.5 days Soil: 30–75 days[1]	Degradation rates for quaternary ammonium ions are variable due to the range of specific substances covered by this term (Texel 2009). Aerobic half-lives are likely to range from days to months. Partition to soils is likely, reducing the mobility of the substance.

Notes: [1] European Chemicals Agency Information on Registered Substances: Quaternary ammonium compounds, (hydrogenated tallow alkyl) trimethyl, chlorides [online].

Available from: https://echa.europa.eu/registration-dossier/-/registered-dossier/10985/5/5/4 [Accessed 2 August 2016].
N/A = not applicable

Hydrochloric acid, glutaraldehyde and quaternary ammonium chloride are considered not to have an environmental risk when used in the context presented here.

The degradation of PAM is complex and without consensus in the literature. PAM adsorbs strongly to soil particles and its degradation occurs slowly in soils (Langenhoff 2011). Although PAM is non-toxic, there is controversy surrounding this substance because its monomer acrylamide (AMD) is neurotoxic. Biodegradation of the polymer does occur, but does not generate AMD (Sojka et al. 2007). Chemical degradation of PAM enhanced by ultraviolet radiation (that is, where handled at the surface or following any surface spills) may produce AMD, but there was no clear consensus within the literature reviewed. Therefore, PAM is considered to be a low environmental risk; this is consistent with its use in the drinking water industry in England.

A.2 The reinjection process

A.2.1 Overview

A range of reinjection and injection activities are being either carried out or considered in England for the production of hydrocarbons. The process for reinjection and injection is broadly similar but with key differences in the volumes, pressures and duration which may result in different geomechanical impacts. The following sections focus on the reinjection process associated with conventional activities (that is, low pressure, high volume, long duration).

The majority of activities in England for conventional operations involve reinjection of produced water back to the formation from which it originated or to different sites within the same oil producing formation.

Based on the Environment Agency's position on conventional reinjection in England (Figure A.1), the following sections look at the reinjection process on the basis of the recognised routes permitting reinjection in England, namely:

- reinjection of produced waters that are required for production purposes to the same site, or to a different site but within a formation where hydrocarbons have been produced, or to a formation determined as permanently unsuitable
- reinjection for disposal (permitted only where NORM is present) to the same formation, or to a formation that has been determined as permanently unsuitable

The potential geomechanical impacts of these different reinjection routes may differ, especially where reinjection is to a formation deemed 'permanently unsuitable' and therefore has not been subject to previous or current oil and gas production activities.

A.2.2 High level principles for reinjection activities

The high level principles behind the reinjection routes detailed above are set out below, characterising the process based on:

- duration

- volume of injected fluid
- nature of the injected fluid
- reservoir pressure condition

The detailed description of the reinjection process given below pays particular attention to the pressure changes that are induced in the reservoir before discussing how the pressure changes can be a mechanism for induced seismicity.

Two key reinjection processes are considered:

- reinjection to facilitate production
- reinjection for disposal (where NORM is present) into other formations where oil and gas production may not have taken place

Reinjection to facilitate production

Reinjection is a recognised strategy within the oil and gas industry to derive value from produced waters. The process of PWRI can be considered, where implemented properly, to be an environmentally attractive management technique while aiding optimisation of the production of oil mainly through maintenance of reservoir pressure.

In a conventional oil and gas reservoir, the pore pressure under which the oil is stored is initially sufficient for hydrocarbons to flow through the rock to the production well. This phase of the reservoir lifecycle is known as primary production.

Over time, pore pressure in the reservoir will tend to reduce as it is depleted of the hydrocarbon it previously contained. Depletion has numerous consequences for the reservoir, one of which is reduced reservoir productivity.

To maintain or increase the well's productivity as it becomes depleted, reinjection wells are drilled in the vicinity of the production well to begin the secondary recovery process. The process usually begins with water flooding where water (or potentially a gas under pressure such as carbon dioxide) is used to maintain reservoir pressure and drive the hydrocarbons towards the production well.

Over time, increasing volumes of water are recovered with the hydrocarbons as their depletion progresses. The produced waters are often recycled back into the reservoir following treatment to remove any particulates and other constituents such as brines and bacteria that could adversely affect the performance of the production.

As noted above, poorly managed treatment of produced waters can lead to injectivity issues such as to 'clogging' of the reservoir in the area surrounding the well. Where produced waters have a high dissolved solids content and are considered a brine, this can be problematic as is the presence of bacteria and their by-products. The presence of brines can lead to unwanted corrosion of the production equipment, with the potential for such corrosion to lead to integrity issues with wells that then require remedial action. The presence of bacterial activity can also lead to clogging of the well, which can result in a loss of injectivity and negatively affect the well's general performance.

The simplified process of reinjection (Figure A.6) can be described in broad terms as follows.

1. Production wells recover oil and produced water from within a reservoir at depth as an oily water mixture.

2. The oil/produced water mix is subjected to oil/water separation to remove the oil which is then sent for further processing.
3. The produced water may be subjected to further treatment to ensure suitability for reinjection. The treatment strategy for produced water will depend on the chemical profile of the produced waters for a given site.
4. The produced water is reinjected via reinjection wells at depth back to another formation or to the same producing reservoir formation to either maintain reservoir pressures or to aid EOR strategies.

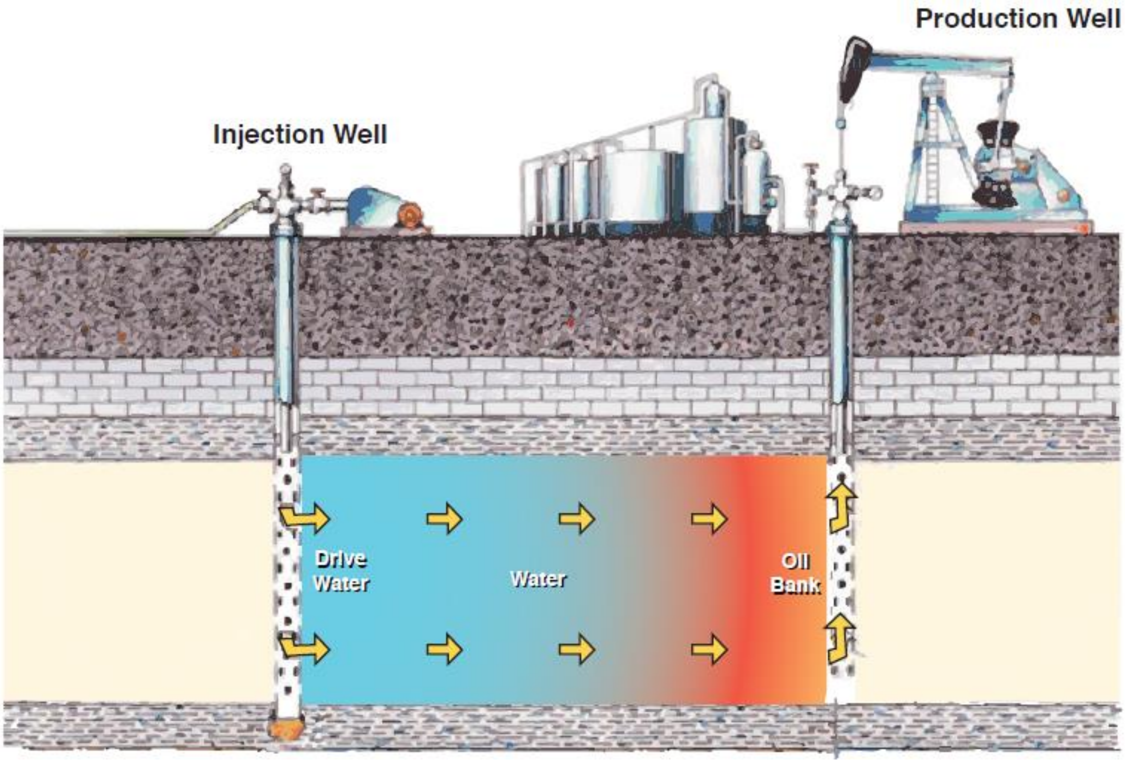

Figure A.6 High level overview of the reinjection arrangement

Notes: Not to scale
In this case, the water flooding process is shown but the arrangement could equally apply to the EOR techniques
Source: National Research Council (2013)

In some instances, the volume of reinjection waters required to maintain the necessary pressures is greater than the volume of recovered liquid (that is, the removal of oil leaves a net loss in volume). Where there is a net loss, additional water is required to maintain the required pressures. This net loss is sometimes made up of sea water or surface water run-off (where collected appropriately). Wytch Farm in Dorset employs a similar process where large volumes of sea water are injected as ‘make-up water’. This is also often supplemented by surface water run-off.

Using make-up water is an established approach in England. However, it is subject to permitting and requires consideration of the chemical implications of using such waters on well integrity and performance, and may require treatment prior to reinjection.

Conventional reinjection schemes generally reinject produced water at low pressures but over long durations (for example, years to decades). The desired pressures used are typically determined through detailed analysis and modelling based on a range of field data. In essence, conventional operations are trying to optimise injectivity and to this end pressures are used to ensure maintenance of existing pressures and to limit the potential for the creation of new or propagation of existing fractures (see the Hall plot in Figure A.2).

This is in contrast to unconventional injection activities such as shale gas where the pressures used are high with short injection durations. The fundamental difference is that shale gas formations are usually characterised as very low permeability formations that require the fracturing of the rock to release oil and gas. In conventional fields, the reservoir formations are typically highly permeable, such as sandstones and limestones) and do not typically require fracturing to release oil and gas.

While schematics such as Figure A.6 are useful at illustrating the general process principles, they tend to oversimplify the complexity of the subsurface geology which can be heavily deformed (for example, folded and faulted). They also tend to mislead the reader on the scale of the operation, particularly the depth at which these activities take place, which is typically in excess of 2km. Although under current legislation all groundwater is protected irrespective of depth or quality, in practice regulators are most focused on shallow drinking water quality aquifers, which are typically located within the top 400m, as well as deep sourced springs and in some instances deeper brackish waters. The schematic in Figure A.6, for instance, suggests that reinjection is occurring at a shallow depth below ground surface, which is not the case for any conventional (or unconventional) oil or gas field in England.

EOR methods can also be employed to increase the recoverability of oil from a reservoir. In England, the extent of EOR strategies is not clear but is generally thought to be limited. A known current example of a large-scale EOR strategy in use is the water flooding EOR strategy employed at Wytch Farm in Dorset. Figure A.6 also serves to illustrate this process as well as the general process of reinjection. In essence, the process at Wytch Farm is the flooding of the reservoir using carefully selected wells allowing the operator to sweep oil towards production wells and hence increase the volume of recoverable oil.

Other EOR methods that are recognised globally, but are understood from the available information reviewed to be limited is their application in England, include:

- heat by way of steam
- carbon dioxide or nitrogen
- chemical polymers
- microbes

The main objective of these methods is to lower the viscosity of oil and hence improve recoverability (National Research Council 2013).

Reinjection to facilitate disposal

While the general process of reinjection to facilitate disposal is the same as that detailed above, some nuances need to be considered where disposal is to a formation that has not been subject to oil and gas production – provided it has been determined to be permanently unsuitable.

Consideration should be given to the properties of the fluid being disposed (for example, brines with high viscosity) as well as the receiving environments condition (for example, existing stress profiles and injection layer static pressures).

Increasing pressures may result in formations that have not been subject to previous PWRI programmes if reinjection schemes are not managed correctly. Increasing pressures may increase the risk of geomechanical impacts such as induced seismicity and/or unwanted fracture propagation.

Summary of the principles of injection activity

The different injection processes can be compared in terms of their typical duration, injection volume, injection fluid and injection pressure regime. The relative differences are presented in Table A.9.

Table A.9 Typical characteristics of injection activities

Characteristic	Reinjection to facilitate production	Reinjection to facilitate disposal
Duration	Long-term (typically years)	Long-term (typically years)
Injection volume	High volume	Moderate to high volume
Injection fluid	Typically treated water and potentially make-up water	May include high viscosity waters
Injection pressure regime	Relatively low	Relatively low
Reservoir pressure regime	Balanced	Potential for positive change increasing with time

A.2.3 Reinjection geomechanics

The general overview below of some key aspects of rock geomechanics in the context of reinjection as discussed in this report focuses on the effects that reinjection can have on the creation and propagation of fractures and the reactivation of existing faults.

General

Trapped hydrocarbons exist within the pore spaces of rock. The hydrocarbon exists under a pressure simplistically determined by the difference between the vertical stress in the rock mass and the overburden pressure. In conventional fields, this pressure is sufficient to cause the hydrocarbon to flow to a production well through the pore spaces at a rate dictated by the hydraulic conductivity of the reservoir (National Research Council 2013).

Any point within the Earth's crust exists within a stress field determined by the tectonics of the region. Where faults and fissures exist they are susceptible to 'slippage' and thus the generation of a seismic event.

The tectonic regime and the overburden controls the magnitude and orientation of the stresses acting on a rock mass, and the faults and fractures contained within the rock mass. The determination of the relative magnitude of the principal stresses is governed by the faulting regime (Figure A.7), although the actual values are considerably harder to obtain accurately in the field.

There are 3 main types of fault (thrust fault, normal fault and strike slip fault), all of which can give rise to seismicity and/or act as pathways for fluids depending on subsurface conditions. In the context of this report, the interest here is in how such faults may be activated to produce seismicity or how they could act as preferential pathways for injected fluids as a result of reinjection activities. Figure A.7 summarises the conditions that must be met to induce movement on a fault and therefore generate seismic energy.

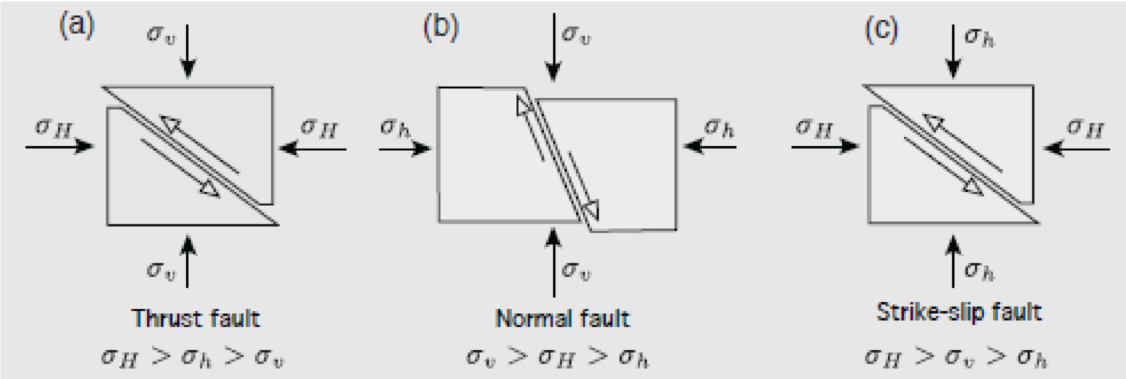

Figure A.7 Faulting regimes and principal stresses

Notes: The principal vertical stress, major horizontal principal stress and minor horizontal principal stress are represented by σ_v, σ_H and σ_h respectively.
Source: National Research Council (2013)

The 3 main fault types are typically activated as follows:

- Thrust faulting – occurs where the major horizontal principal stress (δH) is greater than the minor horizontal stress (δh) which in turn is greater than the principal vertical stress (δv)
- Normal faulting – occurs where the principal vertical stress (δv) is greater than the major horizontal principal stress (δH) which in turn is greater than the minor horizontal stress (δh)
- Strike slip faulting – occurs where the major horizontal principal stress (δH) is greater than principal vertical stress (δv) which in turn is greater than the minor horizontal stress (δh)

In England, such faulting is typically associated with broader (and often regional) geological structures (for example, folds in the subsurface rock formations resulting from deformation events over geological time). All 3 major faults types are present in England and are often associated with the geological structures associated with onshore and offshore oil fields. Many faults may have acted as normal faults at one time and as thrust faults at another, and may or may not have also incorporated some degree of strike slip movement. Major tectonic strike slip faults or fault systems such as the San Andreas fault system in the USA are not present in England, with natural movement on faults are typically small compared with tectonically active regions.

An understanding of the orientation of the faults and fractures in relation to the stress field they exist within gives a reasonable indication as to whether it is likely to trigger seismicity. Sibson (1990) completed a 2D stress analysis applicable to faults that are either purely dip-slip or strike-slip (thrust fault). He classified the faults and fractures as favourably oriented, unfavourably oriented or severely misoriented depending on the coefficient of friction (μ_s) within the fault or fracture (Figure A.8).

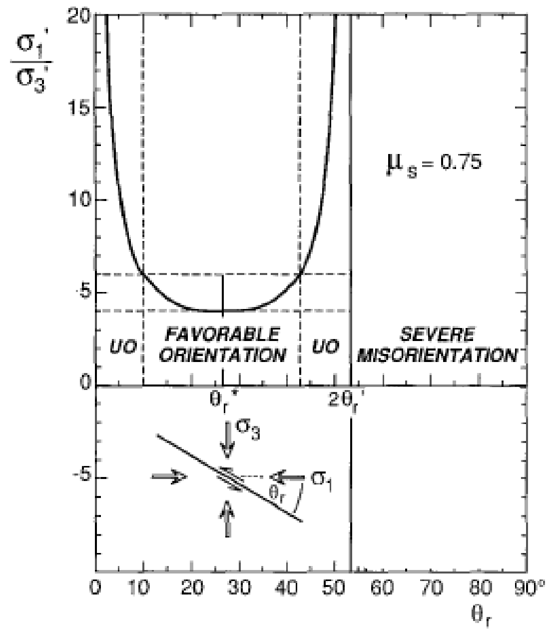

Figure A.8 Determination of the zones of favourable, unfavourable and misorientation of faults

Notes: The major and minor principal stress are represented by σ'_1, σ'_3.
Example includes details of a thrust fault.
Source: Sibson (1990)

'Slip' on faults and fissures

A methodology to quantify and investigate the onset of fault slip is to use the Coulomb friction law, which uses the stresses acting on the faults. This is a frequently employed, commonly accepted and simple way to take into account the resistance to fault slip. However, this is a simplified representation of reality as, in nature, potential fault reactivation and movement will depend on the weakest element on the fault plane (Noda and Lapusta 2013), whereas in a simplified analysis the fault plane is assumed to have constant failure properties (friction and cohesion).

The importance of the stress regime is that stress perturbations influence the magnitude of the stresses and can lead to slippage on a fault or fissure. The influence of the injection procedure on the stress regime is presented in Figure A.9, where it can be seen that increasing pore fluid pressure in rocks and faults reduces their strength and can induce brittle failure (Streit and Hillis 2004). This is caused by increasing pore fluid pressure (P_f) leading to low effective stresses. Positive effective normal stresses confine fault blocks together and resist sliding motion along the fault surface which can be induced by shear stresses acting parallel to the fault. Thus, higher pore fluid pressures reduce the resistance to sliding.

It has been noted by many authors, and most notably by Townend and Zoback (2000), that the state of stress within the Earth's crust is relatively close to the point of failure as governed by the Coulomb failure criterion and therefore only relatively small perturbations in the pore water pressure may induce failure.

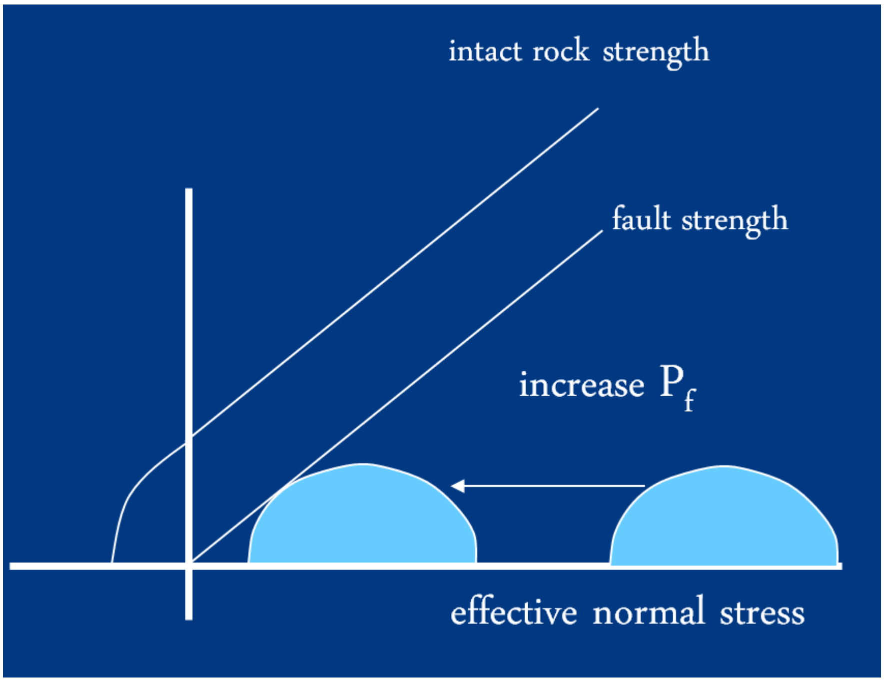

Figure A.9 Influence of stress perturbations on the stress field inducing Coulomb failure represented by Mohr's circles of stress

Notes: P_f is the fluid pressure.

Pore water pressure changes

An understanding of the mechanisms that alter pore water pressure is important in understanding the triggers for seismicity. This is particularly relevant to the process of reinjection fluids as fluids are injected under pressure into deep formations, affecting pore water pressures to varying degrees.

Reinjection to producing formations – secondary and tertiary recovery

In the process of secondary or tertiary recovery and produced water disposal, a large volume of water is injected into the reservoir under a pressure determined by the operator that is deemed insufficient to fracture the rock. It is therefore assumed that any movement of fluid occurs only in the pre-existing fractures in the rock. The increases in pressure caused by this type of reinjection have been described by in a USGS report (Nicholson and Wesson 1951) and can be summarised as follows:

- an initial increase in pore pressure adjacent to the injection, dissipating with distance from the well and governed by the rate of injection and permeability of the rock
- an expanding zone of pore pressure increase throughout the reservoir/disposal formation bounded by the reservoir geometry
- an increase in pore pressure governed by the volume of water injected after the storage capacity of the reservoir/storage formation is reached

The volume of fluid, and the pressure it is injected at, is generally maintained at the static original reservoir pressure during secondary recovery in an attempt to ensure that fracture pressures (see below) are not exceeded. By maintaining the pressure over a sustained period (typically years), it is intended that the reservoir remains under constant pressure and the flow of water flushes the hydrocarbon to the production well.

Reinjection to non-producing formations – disposal

During the disposal of produced water to non-producing formations, the maintenance of constant pore pressure may not be achievable as extraction activities will not be taking place.

Depending on the volumes, rates and pressures used there may be an increased potential for inducing failure on near critically stressed faults compared with producing formations should they be located in the vicinity of the reinjection wells.

Effect of temperature

Consideration also needs to be given to the temperature of the reinjected fluids, especially in relation to the temperature difference between the fluid and receiving formation.

The temperature at which hydrocarbons exist in the reservoir is largely governed by the depth of the reservoir (and the geothermal gradient of the Earth's crust in that region). Shallow reservoirs may exist as temperatures of up to 100°C while reservoirs at great depth may exist at hundreds of degrees Centigrade.

Reinjection fluids are typically introduced at surface temperatures. So although some heating occurs as the fluid travels through the well, the overall effect is typically a cooling of the reservoir during injection.

On cooling, the rock within the reservoir has a tendency to contract, reducing the confining pressure and allowing the release of local stresses (National Research Council 2013).

Fluids injected into the reservoir at higher pressures will gain less heat as they flow through the well than those at lower pressure. They will therefore create a larger temperature differential within the reservoir, thus increasing any susceptibility of the reservoir rocks to contraction. This type of activity may therefore present a higher risk to shale gas hydraulic fracture operations than conventional reinjection activities.

Fracture mechanics

Unlike faults, which are pre-existing structures under stress and can be activated by a change in principal stresses or pore pressures, fracturing is a phenomenon where the rock itself is fractured (that is, the creation of new fractures). As with faults, fractures can also be a source of seismicity and, where created, potentially provide preferential pathways for fluids to travel.

As such, an understanding of fracture mechanics is important to both conventional and unconventional operators alike; however, the application of this understanding is different. For conventional operators, their interest is in what pressures, rates and volumes are acceptable for reinjection so as to avoid the creation of fractures, whereas unconventional operators (such as shale gas operators) wish to understand what pressures, rates and volumes to inject at to achieve the desired fracturing to release oil and gas from impermeable formations.

Davies et al. (2012) collated the research of various authors to describe how fractures form and what factors influence the distances they can travel based primarily on microseismic monitoring at fracking sites in the USA, noting that conventional reinjection activities do not typically generate fractures. Key source material was the work by Fisher and Warpinski (2011), who produced a number of often cited graphs illustrating the relationship between depth of injection, geology and fracture heights in US shales. These graphs are presented in the Davis et al. (2012) paper.

Davies et al. (2012) found that the maximum reported height of an upward propagating hydraulic fracture in the USA is approximately 588m. When they analysed the results from natural hydraulic fracture pipes in Africa and mid-Norway, the maximum height was determined as approximately 1.106m. Note that these natural systems had a long-term high pressure system over geological time, unlike the period of days or weeks for a shale hydraulic fracture operation. The research by Davies et al. (2012) suggested that the probability of a stimulated and natural hydraulic fracture extending vertically greater than 350m was about 1% and 33% respectively. However, this study may be contentious with some questioning the validity of the statistical analysis applied.

In terms of the geomechanics of fractures, hydraulic factures (natural or stimulated) will propagate when the fluid pressure exceeds the minor principal stress and the tensile strength of the rock. They will continue to propagate until these conditions are not met. The fractures propagate in 3 dimensions, typically in clusters around the zone of the well that is being treated. Multiple treatments along the same lateral create a complex network of fractures.

Davies et al. (2012) also noted that, although a typical treatment may only last a few hours, longer treatments (up to 12 hours) do not seem to increase the propagation of fractures significantly. It is only when very large volumes of water are injected at fracture-inducing pressures (that is, high pressures consistent with fracking operations) that they will continue to propagate. In addition, deposits of different lithology and/or permeability are postulated to be natural barriers to hydraulic fracture growth.

In summary, creation of fractures for a conventional operator directing reinjection activities is not an objective. It is actively avoided and as such is generally considered unlikely. The creation of unwanted fractures may also be detected by a levelling off of the volume/pressure curves as presented in the Hall plot in Figure A.2 (that is, a loss of containment). Such an outcome is likely to attract remedial measures to limit any unwanted fractures propagating further.

Consequence of seismicity – liquefaction

Although liquefaction is not a geomechanical process (it is a consequence of geomechanical impacts, particularly seismicity, on particular soil types), it is an important consideration as this process can have damaging effects on infrastructure at the surface and shallow subsurface.

Soil liquefaction is a phenomenon whereby a saturated or partially saturated soil substantially loses strength and stiffness in response to an applied stress. Liquefaction can occur as a result of seismic activity (that is, through ground shaking from an earthquake or from other sudden change in stress conditions), leading to the soil behaving like a liquid, for example, the occurrence of a running sand hazard.

Liquefaction is one of the main mechanisms (other than ground shaking) for causing infrastructure damage at the surface. California in the USA is an area highly susceptible to seismic activity and liquefaction. New hazard maps for northern California have been developed by the Seismological Society of America that delineate the probability of earthquake-induced liquefaction, based on 3 scenarios:

- a magnitude 7.8 event on the San Andreas Fault comparable with the 1906 event
- a magnitude 6.7 event the Hayward Fault comparable with the 1868 event

- a magnitude 6.9 event on the Calaveras Fault

The largest ever recorded earthquake in the UK was M6.1 and was attributed to an area 60 miles offshore at the Dogger Bank in 1931. This event did result in some minor damage to buildings onshore. However, the most damaging UK earthquake was recorded in 1884 in Colchester and resulted in damage to over 1,200 properties. Neither event was associated with any significant liquefaction.

The maximum magnitude earthquake considered to be possible in the UK is M6.5.[8] Events of this size, be they induced or naturally occurring, would likely be very rare (every few hundred years).

Given the general absence of significant seismicity at magnitudes greater than M6 in England and the probability of liquefaction occurring at magnitudes less than M6 being low, liquefaction is generally considered to be very low risk in England. However, there are some areas on the east coast of England (from the Wash into Lincolnshire and also in a smaller area around the Essex and Kent coast) as well as on the west coast along the edges of the River Severn that have a potential for the occurrence of running sand hazards. This typically occurs where soils consist of loose granular sediments that are also saturated with groundwater. This is because a loose sand has a tendency to compress when a load is applied; dense sands in contrast tend to expand in volume or 'dilate'. Running sands may be susceptible to liquefaction at lower magnitude earthquakes than more typical sand deposits.

Summary

In assessing the potential risks of geomechanical impacts such as seismic activity that may be induced by fluid reinjection to deep geological formations, consideration should be given to:

- pressure and temperature changes resulting from the injection of fluid (primarily in the initial stages of the project when the formation temperature is higher than the temperature of the injected fluid)
- the geological structural characteristics (that is, proximity and nature of any major geological faults characterising the formation subjected to reinjection activities)

While a number of approaches and models can be adopted to assess the potential geomechanical impacts of reinjection, such modelling approaches do have some serious limitations concerning the prediction of location and magnitudes of potential earthquakes. This is because they rely on the fault slip for determining the seismic moment and hence the magnitude of induced earthquakes. Collection of field data is crucial in attempting to adequately characterise the subsurface and enable accurate modelling to be undertaken.

To identify whether particular fluid reinjection operations could potentially trigger a fault slip that will induce seismicity, an operator needs to have a good understanding of:

- the geometrical characteristics of the recognised faults (that is, depth and orientation)
- the planned maximum reinjection pressure
- the sliding friction coefficient that is expected to characterise the identified faults

[8] www.bgs.ac.uk/discoveringGeology/hazards/earthquakes/UK.html

To enhance any derived conclusions that may be based on this simplified analytical approach, operators may employ a systematic approach to assess the potential induced seismicity risks associated with any planned fluid reinjection operations. This approach involves:

- carrying out a systematic geomechanical appraisal
- identifying and characterising the existing faults
- measuring the physical properties of the rock
- undertaking numerical modelling of baseline stress, and impacts of fluid reinjection operations on the stress field
- carrying out baseline microseismic and geodetic monitoring before any planned fluid reinjection operations

The extent to which this type of approach is applied in England is detailed in the main guidance part of this report.

Evaluating the potential for induced seismicity in the location and design of reinjection wells, however, is difficult as there are no known cost-effective means to locate and accurately assess fault systems and in situ stresses to the high degrees of confidence necessary to develop robust risk assessments.

A.2.4 Well design and construction

Within the UK, onshore wells are regulated under The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 (DCR). The principal issues concerning well design and construction (including fracturing operations) are addressed in Regulations 13, 14, 16 and 20. In addition, Regulation 5, Schedule 2 (7) of The Borehole Sites and Operations Regulations 1995 (BSOR) apply to onshore well sites and wells.

Discussions with HSE (personal communication, 25 February 2016) revealed that the issue of produced water reinjection is not addressed under DCR or BSOR. However, all operators adhere to their well examination schemes and generally carry out routine monitoring of the wells integrity over the well's operational lifetime.

A number of activities performed by operators on wells require the operator to notify HSE. These activities include:

- drilling of a well
- any workover of a well
- any type of modification (that is, sidetrack and prior to abandonment of the well)

HSE expects weekly reports to be provided where such activities are conducted. However, HSE's main focus in relation to these activities is to ensure that the operator does not exceed the pressure integrity of the well. HSE does not normally ask to see any detailed analysis such as injectivity and falloff testing, with the exception of information on the operator's planned activity which may be included in the well notification.

Once a well is drilled and completed, HSE no longer receives weekly operation reports unless there is a further activity undertaken on the well as set out above. HSE activity is generally only prompted after well completion by:

- a report of an unplanned release of fluids from the well
- deployment of safety equipment to prevent an unplanned release of fluids or other events reportable under Schedule 2 of The Reporting of Injuries, Diseases and Dangerous Occurrences Regulations (RIDDOR)
- the receipt of a complaint about the operation
- the receipt of a further notification (for example, prior to abandonment)

A.2.5 Measures and scale

When reporting on the geomechanical impacts associated with reinjection activities and understanding the potential risks to groundwater or other environmental receptors, it is important to understand the magnitude of the energy released as well as the intensity or damage that can potentially result from a given seismic event.

This is important as, beyond the potential for direct impacts to occur (that is, creation of a direct pathways between the hydrocarbon reservoir and an aquifer via induced faulting or fracturing), indirect impacts may also present unacceptable risks to environmental receptors (for example, damage to a well's integrity or pipelines or fuel storage tanks at the surface resulting from ground movement or shaking).

The OGP guidelines (OGP 2000) set out a process for ensuring containment of reinjected water during the operational period within acceptable zones away from underground sources of usable water for drinking or irrigation. Reliable prediction of the fate of reinjected water is first examined in terms of an 'area of review', which is assessed for the presence of conduits for injectate flow outside of the confinement zone.

Some operators may carry out predictive modelling of produced water reinjection, including both flow (reservoir) simulation and injection well fracturing and fracture propagation. The results of such exercises help to establish the fate of the reinjected water. They thus provide the operator with data to:

- manage the reinjection process throughout the operational reinjection period
- allow an assessment of residual pressure fields after shut-in of the injection well

Monitoring of the mechanical integrity of the injection well or annulus is also integral to proper operation of the reinjection process.

Discussions with HSE (personal communication, 25 February 2016) confirmed that England has not adopted any of the OGP guidelines and no specific focus on seismicity is generally considered. This is likely to do with the absence of evidence linking induced seismicity with conventional reinjection activities or even natural seismicity to damaged infrastructure and the potential loss of containment at depth or at the surface.

Magnitude and intensity

Seismic events are measured according to the amount of energy released (magnitude) or the effect that energy release has at the Earth's surface (intensity). Magnitude scales determine the magnitude of an earthquake from the logarithm of the amplitude of recorded waves. The original magnitude scale was developed by Richter in the 1930s, although this has now been superseded.

Seismic intensity is an indication of how much a seismic event affects structures, people and landscapes at the Earth's surface. Surface effects are compared with a scale originally developed by Mercalli that considers who can feel an event along with visual and structural effects. The Mercalli scale has now been superseded by the European Macroseismic Scale (EMS) (Grünthal 1998), which incorporates new knowledge about how buildings behave during seismic events. It uses 12 categories between I (not felt) and XII (complete destruction) for the individual classification of earthquakes.

The effect a given seismic event will have at the Earth's surface depends on several factors. The deeper a seismic event occurs, the more its radiated energy is attenuated. A deeper seismic event will have a lower intensity than a shallower event of the same magnitude. Different materials also attenuate seismic waves to different degrees. Soft rocks such as shale attenuate seismic waves more than hard rocks such as granite (The Royal Society and The Royal Academy of Engineering 2012).

Within the UK, natural seismicity is low by world standards. Based on data from a national network of seismic stations, the UK experiences seismicity of magnitude 5 ML (felt by everyone nearby) every 20 years, and of magnitude 4 ML (felt by many people) every 3–4 years (Green et al. 2012). Most seismic events in the UK occur at depths of over 10km, limiting the extent to which they are felt at the surface. The average frequency of seismic events in the UK, a descriptor of the effects at the surface and the approximate equivalent EMS scale rating are given in Table A.10.

Table A.10 The average annual frequency of seismic events in the UK

Magnitude scale (ML)	Frequency in the UK	Felt effects at the surface	EMS scale
0.0	–	Not felt	I
1.0	Hundreds each year	Not felt, except by a few under especially favourable conditions	II–III
2.0	25 each year	Not felt, except by a few under especially favourable conditions	
3.0	3 each year	Felt by few people at rest in the upper floors of buildings	IV
4.0	One every 3–4 years	Felt by most people, often up to tens of kilometres away, small objects are shifted, pendulum clocks may stop	V
5.0	One every 20 years	Felt by all people nearby Damage negligible in buildings of good design and construction; a few instances of fallen plaster, some chimneys broken	VII

If the magnitudes of the seismic events are compared with the EMS intensity scale and impact description, an approximate equivalency can be derived against the guideline values defined in the British Standard (BS 7385-2:1993). The Standard indicates that the probability of damage tends towards zero below 12.5mm per second, which is considered to be representative of categories I to V on the EMS intensity scale and equivalent to a magnitude below 4 ML.

Based on the definitions in Table A.10, cosmetic damage would be representative of category VI on the EMS intensity scale and equivalent to a magnitude greater than 4 ML but below approximately 5 ML. Minor damage would be representative of category VII on the EMS intensity scale and equivalent to a magnitude of approximately 5 ML. Major damage would be representative of category VIII on the EMS intensity scale and equivalent to a magnitude greater than approximately 5 ML. Table A.11 shows the EMS intensity rating, the approximate magnitude and the equivalent damage description as detailed in the BS 7385-2.

Table A.11 EMS scale and effects versus ML and BS damage description

EMS scale	Felt effects at the surface	Approximate magnitude value (ML)	BS 7385-2 damage description
I	Not felt	0.0	–
II–III	Not felt, except by a few under especially favourable conditions	1.0	–
	Not felt, except by a few under especially favourable conditions	2.0	–
IV	Felt by few people at rest in the upper floors of buildings	3.0	–
V	Felt by most people, often up to tens of kilometres away; small objects are shifted, pendulum clocks may stop	4.0	–
VI	Felt by all people nearby; damage negligible in buildings of good design and construction – few instances of fallen plaster, some chimneys broken	4.5	Cosmetic damage
VII	Most people are frightened and run outdoors. Furniture is shifted and many objects fall from shelves. Many buildings suffer slight to moderate damage – cracks in walls, partial collapse of chimneys.	5.0	Minor damage
VIII	Furniture may be overturned. Many to most buildings suffer damage: chimneys fall; large cracks appear in walls; and a few buildings may partially collapse. Can be noticed by people driving cars.	5.5	Major damage
IX	General panic. Many weak structures collapse. Even well-built ordinary buildings show heavy damage; serious failure of walls and heavy structural failure.	6	Destructive
X	Most ordinary well-built buildings collapse; some with good earthquake-resistant design are destroyed.	7	Very destructive

A.3 Case studies

A.3.1 Background

Multiple causes of induced seismicity are documented in the literature covering a range of industrial activities. However, very few are related to reinjection activities in conventional oil fields, especially where the geological context is similar to the UK.

This section provides relevant case studies to illustrate the causes and potential consequences of induced seismic events from oil and gas activities, though they may not be directly related to reinjection activities. These case studies have been drawn on to develop the generic guidance presented in this report to aid Environment Agency decision-making when regulating these aspects in England.

In selecting the case studies, attention focused on examples that reflected similar reinjection activities to those that occur or will occur in England at similar depths and in similar geologies to those present in the UK. The selected case studies included induced seismic events that had one or more of the following consequences:

- resulted in contamination of groundwater or other environmental receptors
- resulted in damage to infrastructure (that either did or could have had the potential to result in subsequent contamination)
- may indicate the potential for cumulative affects with adjacent fields
- are perceived as high profile cases that have been misrepresented in the media

Consideration has also been given to a broader spectrum of case studies that have recorded induced seismicity. The aim was to provide a broader context of how reinjection related induced seismicity compares with other industrial activities such as coal mining or mining. This is considered relevant as over 50% of all recorded induced seismic events in the UK are related to the former coal industry.

The broad range of case studies compiled by Davies et al. (2014) are summarised by activity and maximum magnitude in Table A.12. Events associated with reservoir impoundment, mining, and oil and gas withdrawal/production are included, though their mechanism is somewhat different to that of the reinjection activities.

Although there is no formal mechanism to equate the EMS with Mercalli, an attempt to align these 2 scales has been made to aid interpretation of Table A.12. While this is not an established relationship, it does enable a high level appreciation under the new EMS system.

Table A.12 Summary of induced seismic events identified by Davies et al. (2014)

Operation	Number of cases reviewed	Maximum magnitude		EMS
		Richter	Mercalli	
Reservoir impoundment	39	7.9 (ML)	XII	X
Mining	77	5.6 (M0)	VIII	VIII
Oil and gas withdrawal/ production	22	7.3 (ML)	XI	IX
Secondary recovery	20	6 (ML)	IX	IX
Solution mining	3	5.2 (ML)	VII	VIII
Water/waste disposal	8	5.3 (ML)	VIII	VIII
Hydraulic fracturing	3	3.8 (ML)	V	V
Geothermal	22	4.6 (ML)	VI	V
Other/research	5	5.8 (M)	VIII	VIII

A.3.2 Relevant case studies

This section presents a series of cases documented in the literature of various events associated with induced seismicity and groundwater contamination. This is not an exhaustive list of seismic or contamination events, but a selection of the most relevant cases.

Notable induced seismic events from reinjection activities in England are not known, even over the long period which conventional oil and gas operations have been operating in the UK. Regulation on these aspects is also generally absent largely due to the lack of geomechanical impacts noted in England over the past 100 years. However, induced seismicity specifically due to reinjection activities has been documented in other countries including the USA.

Although a wide range of research into induced seismicity has been carried out in the USA, much of this has focused on hydraulic fracking and is therefore not relevant for appraising the potential risks from conventional reinjection activities. Other aspects to bear in mind when referring or using the case studies include the following.

- The papers do not tend to focus on the broad regulatory environment relevant for a given site or recognised good practice approaches that may or may not be in place.
- The papers do not tend to provide a comparative assessment of the tectonic and geological regimes between the USA (a broad mix of seismic and non-seismic areas associated with accretionary, deformed and cratonic crust) and England (which is broadly characterised by low seismicity and comparatively weak sedimentary rocks).
- Conclusions in peer-reviewed papers often indirectly highlight the heterogeneous nature of the Earth's subsurface. The reality of the subsurface provides inherent difficulties when relating one induced seismic event to another.

Some of the these considerations may be key to explaining why England does not have a history of induced seismicity on the scale of the USA, and why regulators have therefore not generally considered these aspects when regulating conventional reinjection activities.

Cogdell oil field, Texas, USA

Sources

Davis and Pennington (1989), Gan and Frolich (2013)

Reason for inclusion

This case study is of particular interest as the Cogdell oil field has experienced induced seismicity during both secondary recovery and EOR operations. In addition, the type and duration of operations reported are not dissimilar to those being conducted in England at Wytch Farm. The geology is also relatively consistent with the conventional limestone reservoirs in the East Midlands and north-east England. However, a comparative assessment of the tectonic regime with England is not provided.

What happened?

The Cogdell oil field in west Texas has been associated with induced seismicity since 1974. Between 1957 and 1982, EOR was implemented in the form of water flooding. Subsequent studies in the USA concluded that this activity had induced earthquakes between 1975 and 1982. However, subsequent monitoring by the National Earthquake Information Center did not detect any further activity between 1983 and 2005.

Further seismic activity was noted between 2006 and 2011, with a reported 18 earthquakes having magnitudes of 3 and greater. Some of these later seismic events were noted to have been potentially sourced from previously unidentified faults. For these quakes, however, the casual factors were not considered to be related to water reinjection but instead potentially related to gas injection (including supercritical carbon dioxide) into the Cogdell field.

Root causes and conclusions

The root cause of the initial seismic activity between 1975 and 1982 that appears to be related to reinjection is considered to have been a result of reinjection into the boundaries of relatively low pressure zones adjacent to high pressure zones. Although the study also suggests reactivation of existing faults, the authors noted that there was little existing evidence (for example, mapped faults on regional geology maps) to identify which faults or fractures where reactivated.

An interesting observation from this study is that no induced seismicity had been recorded in adjacent fields, which had been subject to similar activities. Such outcomes may have implications for cumulative effects. However, the case study does not provide much clarity on this topic.

This study illustrates that both liquid reinjection and gas injection can trigger seismic events and, as such, represents an instance where gas injection has triggered earthquakes having magnitudes of 3 and larger. However, the absence of seismic activity in adjacent fields undergoing similar activities and the potential activation of unknown fault systems highlights the potential complexity of the subsurface and the difficulty in characterising it accurately.

The study recommended that further modelling studies may help to evaluate recent assertions suggesting that significant risks accompany large-scale carbon capture and storage as a strategy for managing climate change.

A summary of the induced seismic events at the Cogdell oil field is presented in Table A.13.

Table A.13 Summary of Cogdell oil field case study

Activity	Secondary recovery (salt water injection)	EOR (carbon dioxide and water injection)
Geology	Canyon Reef (limestone) – Late Palaeozoic – 2.1km depth	
Net injection rate	-1×10^6 rising to $4 \times 10^6 m^3$ per year	Water – negligible Carbon dioxide – negligible from 1990 to 2002, rising to $1.44 \times 10^9 m^3$ per year
Injection duration	1955, peaking in 1974 before drop-off following seismicity	2001 – present
No. of earthquakes	17 exceeding M 2 between 1974 and 1983	18 exceeding M3 between 2006 and 2012
Maximum M	4.6 in 1978 (Modified Mercalli IV–V)	4.5 in 2012 (Modified Mercalli V)
Damage reported	Cracked windows, pictures falling from walls	None reported
EMS – inferred	Inferred EMS scale taking account of cosmetic damage indicates a potential EMS of VI	Inferred EMS based on no reported damage may be between I and V
Contamination reported	None reported	None reported

Dallas–Fort Worth Texas, USA

Source

Frolich et al. (2011)

Reason for inclusion

Although this case study is related to a hydraulic fracturing shale well in Texas, it is included as the induced seismicity appears to be related to the injection of brines for disposal purposes into a formation proximal to where shale gas was being extracted.

As noted previously, disposal of produced waters or other liquids to disposal wells is uncommon in England. Where it is employed as a disposal route, produced water is usually reinjected into the same formations or to formations that are subject to oil and gas production. This is similar to this case study, albeit in this instance it is shale gas that is being extracted with no significant volumes of water being removed or reinjected as part of the gas extraction.

What happened?

Dallas–Fort Worth in central Texas experienced a series of small magnitude earthquakes between October 2008 and May 2009. This site experienced induced seismicity following the reinjection of brines, recovered during flowback from the procedure of hydraulic fracturing, into a formation underlying the Barnett Shale reservoir.

Root causes and conclusions

The study did not attribute drilling, hydraulic fracturing or natural gas extraction to the induced seismicity. Flow rates and pressures were also considered to be within the normal range for disposal wells in this part of Texas, where other sites did not record induced seismic activity. However, the causal factor appears to have been the reactivation of an existing fault following the injection of brines at approximately 4km depth. The authors suggest that pre-existing regional tectonic stresses were a key aspect to this event, ultimately controlling the nature of the seismic event once the fault was reactivated following the injection of fluids.

Frolich et al. (2011) noted that over 200 disposal wells had been drilled locally and, as in the Cogdell oil field case study, a crucial question is why these other locations do not have induced seismicity attributed to them. The authors also noted that it is ‘highly improbable’ that the fluid volumes and pressures being injected at those disposal wells would be likely to affect a large enough area to trigger seismicity on a very long fault (that is, one capable of generating a significant earthquakes).

A summary of the induced events at Dallas–Fort Worth is presented in Table A.14.

Table A.4 Summary of Dallas–Fort Worth case study

Activity	Reinjection of brine flowback fluids
Geology	Ellenburger Formation (dolomite/limestone) – Palaeozoic – 4.2km depth
Net injection rate	$0.5 \times 10^6 m^3$ per ear
Injection pressures	Monthly tubing pressures ranging from 920 to 1,968 psi (6.3–13.6 MPa)
Injection duration	September 2008 to August 2009
No. of earthquakes	>180 recorded earthquakes, 21 in excess of M2
Maximum M	3.3 on 16 May 2009 (Modified Mercalli IV)
Damage reported	Minimal property damage
Contamination reported	None reported

Preese Hall, England

Sources

De Pater and Baisch (2011), Green et al. (2012)

Reason for inclusion

Although this case study relates to activities surrounding the exploitation of shale gas by the hydraulic fracture process, it is included as it is an example of induced seismicity attributed to oil and gas operations in English geology.

This site is of interest as it has experienced seismicity following injection activity associated with hydraulic fracture for shale gas and is a potential target for future oil and gas development in England.

What happened?

Preese Hall in north-west England experienced a series of small magnitude earthquakes in April and May 2011. This site experienced induced seismicity during the injection of hydraulic fracture fluid into the Bowland Shale formation. In addition to numerous earthquakes being recorded and a single earthquake felt at the surface, the wellbore casing also suffered damage that was deemed to be related to the induced seismicity.

Root causes and conclusions

The earthquakes were deemed to have been caused by fluid migrating into a previously unknown pre-existing fault, perturbing the pore pressure to an extent that caused slip on the fault, triggering the seismic events.

It should be noted that only 2 of the 5 treatments caused induced seismicity that has been attributed to injection volume and the flowback extent.

This operation is the benchmark for onshore hydraulic fracturing operations in England as it is the only well to have been drilled and had treatments conducted within. The traffic light system for conducting hydraulic fracture operations has been implemented based on the research surrounding this case.

A summary of the induced events at Preese Hall is presented in Table A.15.

Table A.5 Summary of Preese Hall case study

Activity	Hydraulic fracture for shale gas
Geology	Bowland Shale – Carboniferous (Late Palaeozoic) – 2.5km depth
Net injection rate	Up to $4.4 \times 10^6 m^3$ per year (note this does not include flowback which was noted to be ‘aggressive’ in some treatments)
Injection duration	2–3 hours per treatment 5 treatments in all were carried out in the well
No. of earthquakes	Approximately 50 in total, one in excess of M2
Maximum M	2.3 on 1 April 2011 (Modified Mercalli II–III)
Damage reported	Casing deformation in the well from 2.5km depth
Contamination reported	None reported

Lacq gas field, France

Source

Segal et al. (1994)

Reason for inclusion

The site is one of the best known examples of induced seismicity from pore fluid extraction. Although different to the procedure for the extraction of coal bed methane, this case study highlights an example of how pore pressure reduction can result in significant induced seismicity by a similar mechanism to that of the extraction of fluids for coal bed methane.

What happened?

The Lacq gas field in south-west France experienced a series of earthquakes beginning in 1969. Gas had been extracted from the field since 1950, with no earthquakes greater than M3 recorded prior to 1969.

The number of recorded earthquakes was observed to increase through the 1970s and 1980s, with approximately 40 earthquakes greater than M3 observed at the site.

Root causes and conclusions

The cause of the induced seismicity is deemed to be a result of the reduction in gas pressure within the reservoir as it is extracted. The extraction of the gas was estimated to reduce the shear stress in the ground by only 0.1MPa. This is noted by Segal et al. (1984) to indicate that a very minor pore pressure decrease led to a Coulomb failure, which points towards the theory that the crust is very close to the point of failure (Townend and Zoback 2000).

A summary of the induced events at the Lacq gas field is presented in Table A.16.

Table A.6 Summary of Lacq gas field case study

Activity	Gas extraction
Geology	Lower Cretaceous carbonates and Upper Jurassic dolomites (Mesozoic) – 3.1km depth
Net injection rate	Not applicable. The extraction had been associated with a pressure drop of 60MPa.
Injection duration	Not applicable. The period of extraction covered in this case study is 1960 to 1990.
No. of earthquakes	Over 800 in total, approximately 40 greater than M3
Maximum M	4.2 on (Modified Mercalli VI)
Damage reported	None reported
Contamination reported	None reported

Tordis field, Norwegian North Sea

Source

Løseth et al. (2011), Davies et al. (2012)

Reason for inclusion

The site is one of the few reported cases of a vertically propagating ‘hydraulic’ fracture reaching the ground surface (in this case the seabed) which was attributed to high pressures used during a reinjection activity. Although the ground conditions and depth at which the activity was being carried out at are not comparable with conventional oil and gas activities in England, it is one of very few examples of produced water activities causing a contamination event.

What happened?

The Tordis field in the Norwegian North Sea experienced a contamination event associated with the reinjection of waste water. Following a sustained period of injection at a relatively shallow depth compared with conventional onshore oil and gas activities in England, a hydraulic fracture managed to propagate to the sea bed where it formed a 7m deep 40m wide crater and created a path for the injected fluid to contaminate the sea water.

Root causes and conclusions

The procedure being undertaken at the Tordis field is similar to the waste water injection techniques and the mechanism for the created fracture is consistent with that used in hydraulic fracture. The cause of this fracture propagation is noted to be the stepwise fracturing of the overburden with high pressures and high volumes of fluid, estimated to be 125 times greater than would be used in hydraulic fracturing techniques (that is, very high pressures and volumes).

Onshore produced water reinjection techniques are generally applied to deep basement rocks rather than at the relatively shallow depth at the Tordis field and at significantly lower pressures. So while alluding to the potential for propagating fractures to the surface, this case study is not fully applicable to the techniques described in this study. The distances hydraulic fractures are expected to travel are discussed by Davies et al. (2012).

A summary of the contamination event at the Tordis field is presented in Table A.17.

Table A.7 Summary of Tordis field case study

Activity	Offshore wastewater injection
Geology	Hordland Group – Eocene/Miocene (Cainozoic) – 900m depth
Net injection rate	$2.6 \times 10^6 m^3$ per year
Injection duration	5.5 months
No. of earthquakes	None reported
Maximum M	Not applicable
Damage reported	Formation of a 7m deep, 40m wide crater
Contamination reported	Between 16 and 77 days or $150{,}000 m^3$ and $550{,}000 m^3$ of waste water released to the sea (details of the implications are not reported)

East Pennsylvania, USA

Sources

Davies (2011), Osborn et al. (2011), Davies et al. (2012)

Reason for inclusion

This case study is an example of contamination being attributed to oil and gas activities due to the migration of methane gas from the reservoir formation. The hydraulic fracture technique being undertaken in east Pennsylvania is similar to that proposed in England. The geology of the 2 regions is not dissimilar and the gap between the reservoir and aquifer is also similar.

What happened?

Aquifers overlying the east Pennsylvania shale play have experienced contamination from methane gas. The causes of the contamination were argued by Osborn et al. (2011) to be a result of vertically propagating hydraulic fractures. Davies (2011), however, considered a more likely contamination path to be through casing leaks in abandoned or poorly cemented hydrocarbon wells.

Root causes and conclusions

If hydraulic fractures propagate as far as Osborn et al. (2011) suggest, then there is the potential for a contamination event. However, as noted by Davies (2011) and evidenced in Davies et al. (2012), the likelihood of a stimulated hydraulic fracture propagating more than 350m is conservatively estimated to be 1% and the longest hydraulic fracture recorded in the Marcellus Shale is approximately 530m.

The hypothesis that the methane migration has occurred through leaky well casing proposed by both sets of authors therefore seems a more plausible reason for the contamination. Although the number of onshore oil and gas wells in England is currently limited, the potential increase in wells required for shale gas production could lead to a greater potential for this mechanism of contamination to occur without robust well casing design and construction oversight from HSE.

A summary of the contamination event in east Pennsylvania is presented in Table A.18.

Table A.8 Summary of east Pennsylvania case study

Activity	Hydraulic fracture for shale gas
Geology	Shale play – Marcellus Shale – Devonian (Palaeozoic) – 2km depth Aquifers – Catskill, Lockhaven and Genesee formations – sandstone, mudstone, shale (Devonian) – 35–190m depth
Net injection rate	Not reported. An injection volume of approximately 15,000m^3 of water per well is reported.
Injection duration	Not reported
No. of earthquakes	None reported
Maximum M	Not applicable
Damage reported	None reported
Contamination reported	Methane contamination of the overlying aquifers

Wilmington oil field, California, USA

Sources

Mayuga (1968), Nicholson and Wesson (1951), Ottot and Clarke (1996), Dusseault et al. (2001)

Reason for inclusion

This case study is of interest because Wilmington oil field experienced borehole casing damage as a result of induced seismicity. The seismic events were caused by land subsidence due the extraction of oil and gas, and the reinjection was introduced at the oil field later to control the land subsidence. Reinjection was therefore not the cause of the seismic events. However, this case study does demonstrate that induced seismicity can cause severe damage to borehole casing.

No contamination was reported as a result of the damage to the borehole casing. However, damage to casing in an oil well has the potential to cause groundwater contamination.

When assessing the relevance of this case study, it should be noted that this is a historical event where the boreholes were built pre-1950s. Current borehole design, construction and materials are likely to be superior to those reported in this case study. Furthermore, all boreholes built in the UK must adhere to the stringent guidance outlined by HSE.

What happened?

Extensive oil extractions from the Wilmington oil field resulted in significant land subsidence. Between 1928 and 1970, up to 8.8m of rapid land subsidence was observed. The rapid land subsidence resulted in damaging earthquakes in 1947, 1949, 1951, 1954, 1955 and 1961. The biggest earthquakes occurred in 1949 and resulted in almost 200 wells going out of production (Nicholson and Wesson 1951).

In 1953, a pilot scheme of water injection (repressurisation) was introduced in an attempt to control land subsidence and increase oil recovery. In 1956, the pilot scheme was expanded to be field wide (Ottot and Clarke 1996). Repressurisation had successfully stopped land subsidence by 1968.

Root causes and conclusions

Between 1947 and 1961, reservoir compaction and production stress changes resulted in severe casing damage to over 500 wells. The damage included compression in the producing intervals and shear damage in producing intervals and overburden. The majority of well damage was associated with subsidence-induced bedding plane slip and low angle faulting.

During the period of maximum subsidence in the 1950s, hundreds of oil well casings were sheared, with much of the shear movement was confined to thin beds of clay shale. The maximum horizontal shearing movement was 225mm (Dusseault et al. 2001).

A summary of the seismic events that occurred at Wilmington oil field are presented in

Table A.9.

Table A.9 Summary of Wilmington Oil Field Case Study

Activity	Fluid extraction followed by secondary recovery (salt water injection)
Geology	Catalina Schist, overlain by 8,000 feet of Miocene and Pliocene sediments Main oil producing zones: Puente and Repetto sandstones Traverse faults divide producing reservoirs into separate pools (Mayuga 1968)
Net injection rate	Around 6×10^6 m^3 per year (1926–1958) rising to around 4.5×10^6 m^3 per year (1977–2014) Fluid
Injection duration	A pilot water injection operation was started in 1953 in an attempt to control land subsidence and increase oil recovery. This was increased to field wide operation in 1956.
No. of earthquakes	6 earthquakes (1947–1961)
Maximum M	M2–M4
Damage reported	Hundreds of oil well casings were sheared at around 500m below the surface. 15m casing joints were shortened as much as 400mm.
Contamination reported	None reported

Loma Prieta earthquake, California, USA

Source

Schiff (1989)

Reason for inclusion

The Loma Prieta earthquake was included as it highlights the risk of damage to pipelines during earthquakes. This is considered important as extensive pipeline infrastructure is associated with conventional oil and gas production. This case study focuses on the damage to the water and waste water pipelines as it is relevant to reinjection and extraction activities.

This earthquake was not caused by induced seismicity and is much larger than earthquakes experienced in the UK. However, this case study demonstrates the importance of appropriate guidance for designing robust and earthquake-resistant infrastructure.

What happened?

The Loma Prieta earthquake took place in northern California in 1989. The earthquake was magnitude 6.9 Mw (National Research Council 1994) and caused extensive infrastructure damage to lifeline services including electrical power systems, communication systems, water and waste water distribution systems, transportation systems (including bridges and sea ports) and natural gas systems. This case study focuses on the severe damage done to the water and waste water lifelines.

Root causes and conclusions

Most of the damage was found to be in regions that experienced liquefaction or where infrastructure did not have proper seismic design or construction.

In the central San Francisco Bay area, it was reported that the damage to the water pipelines occurred as a result of liquefaction. The pipelines suffered breaks due to tension, compression or bending.

In southern San Francisco Bay area (San Jose, Cupertino, Campbell, Los Gatos and Los Altos), 120 water main repairs were reported. More than half of the leaks were reported to be holes in the pipe caused by corrosion; others were caused by pulled joints and circular breaks. The leaks occurred in pipes less than 4 to 37 inches in diameter made from steel, cast iron asbestos cement and ductile iron. A total of 75 of the leaks occurred in 30-year-old steel pipes with limited corrosion protection.

The guidance for design of pipelines in the UK is very limited (see Section A.1.2). It is unlikely that this guidance would prove sufficient for an earthquake of this magnitude, which could be a consideration for future guidance.

A summary of the seismic events of the Loma Prieta earthquake is presented in Table A.20.

Table A.10 Summary of Loma Prieta earthquake case study

Activity	N/A
Geology	The Loma Prieta region is divided by the San Andreas and Zayante faults into 3 structural blocks with different basement terranes. Cretaceous granite and Salinia terrane are south-west of the Zayante fault. North-east of the fault, the basement is covered by a tertiary sedimentary section (up to 6km thick). The 1989 Loma Prieta earthquake is associated with the Zayante fault at 7–10km depth, suggesting secondary fault reactivation (Well 2004)
Nett injection rate	N/A
Injection duration	N/A
No. of earthquakes	1 (1989)
Maximum M	6.9
Damage reported	More than 1,200 leaks and breaks in the water mains, which resulted in loss of water supply in some areas of the region.
Contamination reported	There were concerns over the possible contamination of the water supply due to burst water mains, which resulted in ‘boil water’ notices being issues in 4 cities in the region. However, no contamination was found.

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