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Facilitating sustainable geo-resources exploitation: A review of environmental and geological risks of fluid injection into hydrocarbon reservoirs

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ABSTRACT

Natural gas is an important low-carbon geo-resource for sustaining future energy demand. However, production is currently impeded by the negative effects of reservoir compaction, i.e. induced seismicity and surface subsidence. Fluid injection into producing or depleted hydrocarbon reservoirs is one of the strategies to mitigate compaction, though it may introduce other negative consequences. This study aims to identify lessons and potential knowledge gaps on the causes and mechanisms of consequences of such injection operations. An overview of the environmental and geological hazards and risks is developed by examining literature on four commonly injected fluids, i.e. CO_2, methane, nitrogen and wastewater. The well-recognised hazards are leakage, reservoir deformation and induced seismicity, which have consequences for several environmental receptors, e.g. the atmosphere, surface sediments and water, subsurface resources and groundwater. Generally, in defining the risk, there is a consensus on the probability of hazards occurrence, while a lack of knowledge on the hazard impacts exists. The assessment approaches analysis also indicates that consequence magnitude evaluations and comparisons to thresholds are often missing from the risk assessments. For all examined injection fluids, knowledge on hazard occurrence, hazard exposure and receptor affectability is insufficient. Furthermore, in complex subsurface systems with high uncertainty, more insight in the probability of multiple hazards occurrence and the corresponding cumulative risks is needed.

1. Introduction

Natural gas serves as a low-carbon alternative to coal and oil and plays an important role in the sustainable energy transition (IEA, 2016). However, adverse effects of the subsurface activities regarding natural gas exploitation have been widely recognised. Induced seismicity and surface subsidence are observed worldwide above producing and depleted reservoirs (Dahm et al., 2007; Menin et al., 2008; Simpson and Leith, 1985; Suckale, 2010; Van Eijs et al., 2006; Van Thienen-Visser and Breunese, 2015). These adverse effects can damage the natural and built environment, and consequently, hinder the sustainable exploitation of geo-resources.

Induced seismicity and surface subsidence are typically related to production-induced compaction of the reservoir rock (Spiers et al., 2017). A potential strategy to reduce the risk of natural gas production is to mitigate reservoir compaction by injecting pressurised fluids into the producing or depleted reservoir (Teatini et al., 2011b). The effect of injection is twofold. Firstly, the pore pressure in the reservoir is restored, which reduces the effective stress acting on the reservoir rock (Terzaghi, 1943; Wang, 2000). This allows for poro-elastic rebound of the reservoir and surface, though any permanent compaction which may have developed during depletion is not counteracted. In addition, the mechanical driving force for permanent and time-dependent (creep) deformation is reduced (Doornhof et al., 2006; Nagel, 2001). Secondly, injection of a novel fluid changes the chemical environment within the reservoir. Pore fluid chemistry affects the processes causing creep in compaction experiments on sand aggregates (Brzesowsky et al., 2014; Chester et al., 2007; Hangx et al., 2010) and sandstones (Hu et al., 2018, 2016) and is therefore expected to influence compaction at the reservoir scale. Injection of a fluid with suitable properties can mitigate reservoir compaction both mechanically and chemically.

In addition to mitigating reservoir compaction, fluid injection into hydrocarbon reservoirs is applied worldwide for different purposes. CO_2 and wastewater are injected for permanent waste storage (Keranen

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et al., 2013; Lei et al., 2013; Ringrose et al., 2013; Underschultz et al., 2011). Methane is injected for temporary storage to meet seasonally fluctuating energy demands (Fang et al., 2016; Juez-Larré et al., 2016). Injection is also widely applied in enhanced oil recovery (EOR) where fluids, such as CO_2 and nitrogen, steam, and chemically active fluids, are injected to decrease the viscosity and increase the mobility of oil (Bai et al., 2017; Guzmann, 2014; Shik Han et al., 2010; Whittaker et al., 2011). However, these subsurface activities are not free of environmental and geological impacts (Gill and Malamud, 2017; Liu and Ramirez, 2017). For example, leakage of the stored substance may affect climate (Deng et al., 2017) or potable aquifers (Harvey et al., 2013; Qafoku et al., 2017), while stress changes within the earth have the potential to induce earthquakes (Ellsworth, 2013; Foulger et al., 2018; Suckale, 2010; Zoback and Gorelick, 2012).

These risks are thoroughly analysed in studies on CO_2 injection, resulting in multiple risk assessments and numerous risk overviews (Anderson, 2017; Carroll et al., 2016; Condor et al., 2011; Damen et al., 2006; Deng et al., 2012; Harvey et al., 2013; Ko et al., 2016; Koornneef et al., 2012; Pawar et al., 2015; Qafoku et al., 2017; Shukla et al., 2010). However, similar overviews are not available for other fluids commonly injected, such as nitrogen, methane or wastewater. As risks may differ per injection fluid, the full scope of the hazards and risks of fluid injection into hydrocarbon fields is unknown. In addition, to the best of authors' knowledge, no comparison has been made on either method applications or assessment results. Such a comparison is necessary to identify lessons learned and knowledge gaps, and to allow knowledge transfer, which may also help to identify 'black swan' events, i.e. low probability or unexpected events with potentially a high impact (Aven, 2015; Taleb, 2008). Identifying and comparing injection risks of multiple fluids facilitates the decision making process of whether fluid injection is a safe strategy to mitigate reservoir compaction.

The objective of this study is to develop a qualitative overview of the environmental and geological risks of fluid injection into hydrocarbon reservoirs. This is done by reviewing the existing literature on CO_2, methane, nitrogen and wastewater injection for hazards and risks. The resulting logic tree is validated in an expert workshop. In addition, risk assessment methods applied in the existing literature are critically analysed. Lastly, hazards, risks and assessment methods for the different fluids are compared to identify lessons learned and knowledge gaps.

2. Methodology

A systematic approach was developed for this study and involved the following steps: 1) formulating research scope; 2) critically selecting literature; 3) reviewing literature; 4) validating the results in an expert workshop; and 5) identifying lessons learned and knowledge gaps.

2.1. Research scope

This study aimed to map the *environmental* and *geological risks* of fluid injection into producing or depleted hydrocarbon reservoirs. Operational and economical risks were excluded. In addition, injection into saline aquifers or other subsurface storages was omitted, as injection will result in a net increase in the pore pressure, representing a different scenario. Four fluids were selected, i.e. CO_2, methane, nitrogen and wastewater, as they are already injected into hydrocarbon reservoirs in both pilot projects and at industrial scale, and studies are available on the targeted research topic.

2.2. Literature selection

The formulated research scope was applied as a primary criterion for the literature selection. In addition, the following criteria were also applied: literature is written in English, published between 2007 and 2017, and went through a peer-reviewed process, i.e. also including internally reviewed reports and conference proceedings. The resulting selection contained a large number of studies on CO_2 and methane injection. The final number of studies per injection fluid was balanced and determined by filtering for studies of a quantitative nature, while ensuring the selection covered a wide range of environmental and geological issues. The final selection included eleven studies on CO_2 injection (Apps et al., 2010; Ayash et al., 2009; Ferronato et al., 2010; Karimnezhad et al., 2014; Oldenburg et al., 2011; Pawar et al., 2016; Rutqvist et al., 2014; Soltanzadeh and Hawkes, 2012; Tambach et al., 2015; Viswanathan et al., 2008; Zheng et al., 2012), nine on methane (Baciu et al., 2008; Ingraffea et al., 2014; Khaksar et al., 2012; Orlic et al., 2013; Schout et al., 2017; Tang et al., 2013; Teatini et al., 2011a; Tenthorey et al., 2013; Zheng et al., 2017), two on nitrogen (NAM, 2016a; TNO, 2015) and six on wastewater (Akob et al., 2016; Andričević et al., 2009; Goebel et al., 2016; NAM, 2016b, 2016c; Weingarten et al., 2015). In general, less literature was available on nitrogen and wastewater injection. The uneven distribution of literature did not allow making a statistical analysis of the results.

2.3. Literature review

The focus of the literature review was threefold. Firstly, the environmental and geological hazards of fluid injection were collected and formatted into bow-tie like look-up tables. These tables are fluid specific and explicitly show hazards, causes, receptors, consequences, and literature sources. The fluid specific results were combined into a logic tree on fluid injection in general. Secondly, hazard-receptor combinations were derived from the logic tree and the literature was reviewed to determine qualitative risks for these combinations. This was done by evaluating the hazard probability and consequence impact based on values derived from the literature. Thirdly, risk assessment approaches used in the selected literature were analysed, including the applied risk assessment stages and assessment methods.

2.4. Results validation via expert workshop

The logic tree on fluid injection was validated in an expert workshop. The workshop participants were selected from a broad range of backgrounds (e.g. environmental and energy sciences, and geology, etc.) and were working in academia or industry (see Appendix A). The logic tree was presented in the workshop and the participants evaluated the map in terms of 1) correctness, i.e. whether elements in the logic tree were valid and the posed relations between causes, hazards and consequences were correct, and 2) completeness, i.e. whether elements were missing or surplus. Afterwards, the logic tree was adjusted accordingly.

2.5. Lessons learned and knowledge gaps identification

Lessons learned and potential knowledge gaps of fluid injection into hydrocarbon reservoirs were identified by comparing the hazard look-up tables, risks of hazard-receptor combinations, and assessment approaches. In addition, feedback from the expert workshop contributed to the process of knowledge gap identification.

3. Hazards of fluid injection

For each fluid, the literature review resulted in an overview of the hazards of injection. CO_2 leakage, reservoir deformation and induced seismicity were recognised as hazards in the literature on CO_2 injection (Table 1). The same hazards were described in the literature on methane injection (Table 2). The literature on nitrogen injection only considered induced seismicity (Table 3), while leakage and induced seismicity was the focus of the wastewater injection literature (Table 4). The results of the different fluids were combined into a general logic tree (Fig. 1).

Table 1

Hazards of CO_2 injection and associated literature.

Underlying cause	Cause	Hazard	Receptor	Primary consequence	Secondary consequence
● Fault reactivation (3, 8)	Temporary conduit (3, 8)	Leakage	Atmosphere	● Release of CO_2 (6, 10)	
● Cement dissolution (10) ● Diffusion (9) ● Fracture formation (10) ● Inadequate cementation (6, 10) ● Matrix flow (10) ● Micro-annulus formation (10)	Well failure (5, 6, 9, 10)		Subsurface resources	● Contaminate (5)	● Affect resource quality (5)
● Diffusion (9) ● Fracture formation (3, 4, 5, 8) ● Displacement via reservoir deformation (4)	Caprock failure (3, 4, 5, 8, 9)		Groundwater	● Decrease pH (1, 6, 11) ● Contaminate (5, 10) ● Increase TDS (6, 11) ● Mobilise hazardous trace elements (1, 11)	● Affect groundwater quality (1, 5, 11)
● Poro-elastic response (3, 4)	Reservoir expansion (3, 4)	Reservoir deformation	Surface	● Displacement (3)	● Damage buildings and infrastructure (3) ● Damage environment (3)
● Effective stress change (2, 3, 7, 8) ● Poro-elastic response (3, 7, 8)	Fault reactivation (2, 3, 7, 8)	Induced seismicity	Surface	● Ground shaking (7)	● Damage buildings and infrastructure (7) ● Nuisance to human (7)

Note. 1 (Apps et al., 2010); 2. (Ayash et al., 2009); 3. (Ferronato et al., 2010); 4. (Karimnezhad et al., 2014); 5. (Oldenburg et al., 2011); 6. (Pawar et al., 2016); 7. (Rutqvist et al., 2014); 8. (Soltanzadeh and Hawkes, 2012); 9. (Tambach et al., 2015); 10. (Viswanathan et al., 2008); 11. (Zheng et al., 2012).

3.1. *Causes for leakage*

3.1.1. *Well failure*

The wellbore connects the reservoir to the surface and is encased in steel and cement that prevent the fluid injected or produced from spreading into layers overlying the reservoir, including aquifers. After injection or production is completed, the well is abandoned and plugged with cement to seal the wellbore. In case of well failure, the barrier function is defective, such that fluids in the reservoir can escape through the wellbore. Seven categories for well failure are identified, including blowout, cement dissolution, diffusion, fracture formation, inadequate cementation, matrix flow and micro-annulus formation (CO_2 and methane literature; Tables 1 and 2; Fig. 1).

The first category, well blowout, is an abrupt and uncontrollable release of the stored substance through the well to the surface or any location along the well trajectory (Schout et al., 2017). Dissolution can affect the cement that plugs or encases the wellbore, however, dissolution were rarely observed in wellbore cement exposed to CO_2 (Viswanathan et al., 2008). Alternatively, the stored substance can diffuse through the cement, reaching up to 3.8 cm in 100 years and leaving a reaction tail with dissolved portlandite and precipitated calcite (Tambach et al., 2015). Flow through the cement matrix can also be a consequence of a poor cement quality (Ingraffea et al., 2014; Viswanathan et al., 2008). In addition, inadequate cementation can lead to open annular regions through which fluids may migrate (Ingraffea et al., 2014; Viswanathan et al., 2008). Pressure and temperature fluctuations during injection or production can create fractures in the cement and micro-annuli between the cement and steel casing (Ingraffea et al., 2014; Viswanathan et al., 2008). These fractures can connect to form a network for fluid flow.

Table 2

Hazards of methane injection and associated literature.

Underlying cause	Cause	Hazard	Receptor	Primary consequence	Secondary consequence
	Permeable fault (12, 17)	Leakage	Atmosphere	● Release of methane and associated gasses (14, 17)	
● Blowout (16) ● Fracture formation (14) ● Inadequate cementation (14) ● Matrix flow (14) ● Micro-annulus formation (14)	Well failure (14, 16)		Groundwater	● Increase pH (16) ● Change redox conditions (16) ● Contaminate (14, 16)	● Affect groundwater quality (16)
● Capillary sealing failure (20) ● Fracture formation (13, 19, 20) ● Displacement via reservoir deformation (19)	Caprock failure (13, 19, 20)		Surface	● Build-up of methane (12, 14, 16)	● Asphyxiation (12, 16) ● Explosion (12, 14, 16) ● Fire (12) ● Damage buildings and infrastructure (12)
● Fault reactivation (13, 19, 20)	Temporary conduit (13, 19, 20)				
● Poro-elastic response (18, 19)	Reservoir compaction (18, 19)	Reservoir deformation	Surface	● Displacement (18, 19)	● Damage buildings and infrastructure (18)
● Poro-elastic response (18, 19)	Reservoir expansion (18, 19)				● Damage environment (19)
● Effective stress change (13, 15, 19) ● Poro-elastic response (13, 15, 19) ● Thermal stress change (15)	Fault reactivation (13, 15, 19, 20)	Induced seismicity			

Note. 12 (Baciu et al., 2008); 13. (Khaksar et al., 2012); 14. (Ingraffea et al., 2014); 15. (Orlic et al., 2013); 16. (Schout et al., 2017); 17. (Tang et al., 2013); 18. (Teatini et al., 2011a); 19. (Tenthorey et al., 2013); 20. (Zheng et al., 2017).

Table 3
Hazards of nitrogen injection and associated literature.

Underlying cause	Cause	Hazard	Receptor	Primary consequence	Secondary consequence
● Effective stress change (21, 22) ● Poro-elastic response (21, 22) ● Stress field change (22) ● Thermal stress change (22)	Fault reactivation (21, 22)	Induced seismicity	Surface	● Ground shaking (21)	● Damage buildings and infrastructure (21) ● Injury (21) ● Nuisance to human (21)

Note. 21. (NAM, 2016a); 22. (TNO, 2015).

3.1.2. Fluid migration

Fluid migration to outside the hydrocarbon reservoir is nominally prevented by the reservoir structure, the presence of a caprock and impermeable faults. However, in some cases a mix of permeable and impermeable layers surrounds the reservoir that could allow lateral and vertical flow (wastewater literature; Table 4; Fig. 1). Wastewater leakage through randomly distributed permeable sandstone (75%) and impermeable marl (25%) was found to spread laterally and vertically up to 500 m and 150 m, respectively, in 100 years (Andričević et al., 2009). In addition, fluid migration can occur when the reservoir is filled to its spill point, i.e. the structurally lowest point in a hydrocarbon trap. From this point the reservoir fluids can migrate into the sideburden and underburden. Alternatively, the stored fluid can dissolve into fluid flows along the bottom of the storage reservoir and get transported elsewhere.

3.1.3. Permeable fault

Some faults are natural conduits, potentially connecting deep reservoirs to the overburden, such as aquifers or shallow sediments. As a result, stored, buoyant fluids can diffuse through the fault, accumulate in the overburden and spread lateral (methane literature; Table 2; Fig. 1). Field measurements in Romania (Baciu et al., 2008) and China (Tang et al., 2013) provided evidence for the existence of natural seepage zones in faulted areas. To illustrate, methane concentrations in soil gas samples from unfaulted areas increased from 2 mg/m^3 at the surface to 2.5 mg/m^3 at 1.5 m depth, while methane concentration in faulted areas increased to 4 mg/m^3 (Tang et al., 2013). The existence of naturally permeable faults is a site specific characteristic that depends on the local geology.

3.1.4. Caprock failure

The caprock is a low permeability layer that seals off the top of the reservoir and prevents fluids from migrating upwards. If the caprock fails, leakage pathways are created due to capillary sealing failure, diffusion, caprock dissolution or fracture formation (CO_2, methane and wastewater literature; Tables 1, 2 and 4; Fig. 1). Capillary sealing failure means that locally the pore pressure exceeds the capillary force of the caprock such that the injected fluid can penetrate the caprock. Generally a pore fluid pressure far greater than the pore pressure prior to depletion is required to exceed the capillary force (Zheng et al., 2017).

The caprock also interacts chemically with the stored fluid via diffusion and dissolution. CO_2 can diffuse 6.4 m into caprock in 100,000 years, which is minor compared to the total caprock thickness (Tambach et al., 2015). Maximum dissolution of a halite-rich caprock occurs when the injected fluid is free of halite and becomes fully saturated with time. Full saturation of injected wastewater occurred after 8000–73,000 years, depending on reservoir permeability, which required $< 0.5\%$ of the total caprock volume to dissolve (NAM, 2016c).

Lastly, injection into a reservoir induces stress and temperature changes in both the reservoir and caprock. This may lead to the formation of tensile and shear fractures that can form a leakage pathway if connected (Ferronato et al., 2010; Karimnezhad et al., 2014; Khaksar et al., 2012; Oldenburg et al., 2011; Soltanzadeh and Hawkes, 2012; Zheng et al., 2017). In the reviewed studies, fracture formation was found to be unlikely, as pore pressures of 22 MPa and 20.7 MPa were needed to induce tensile and shear fracturing, respectively, which were well above the intended injection pressure of 11 MPa (Khaksar et al., 2012). However, these findings are extremely site specific and depend on the local geology, stress field, rock properties, injection strategy, etc.

3.2. Consequences of leakage

3.2.1. For the atmosphere

Leakage to the *atmosphere* releases stored and associated gasses (CO_2 and methane literature; Tables 1 and 2; Fig. 1). Release of these gasses can affect the air quality. Direct leakage via an open wellbore would release approximately 50,000 and 150,000 t CO_2 over 200 and

Table 4
Hazards of wastewater injection and associated literature.

Underlying cause	Cause	Hazard	Receptor	Primary consequence	Secondary consequence
● Lateral flow (24) ● Vertical flow (24) ● Dissolution (27)	Fluid migration (24) Caprock failure (27)	Leakage	Surface sediments	● Reduce diversity microbial communities (23) ● Increase Fe(III) concentration (23)	● Affect biochemical nutrient cycling (23) ● Affect ecosystem functions (23) ● Affect sediment quality (23)
			Surface water	● Increase NVDOC (23)	● Affect surface water quality (23)
			Groundwater	● Increase (23) ● Contaminate (24)	
● Chemical weakening (26) ● Effective stress change (25, 26) ● Poro-elastic response (25, 26) ● Stress field change (26) ● Thermal stress change (26)	Fault reactivation (25, 26, 28)	Induced seismicity	Surface	● Ground shaking (25, 26, 28)	
● Dissolution (27)	Caprock failure (27)	Caprock deformation	Surface	● Displacement (27)	

Note. 23. (Akob et al., 2016); 24. (Andričević et al., 2009); 25. (Goebel et al., 2016); 26. (NAM, 2016b); 27. (NAM, 2016c); 28. (Weingarten et al., 2015).

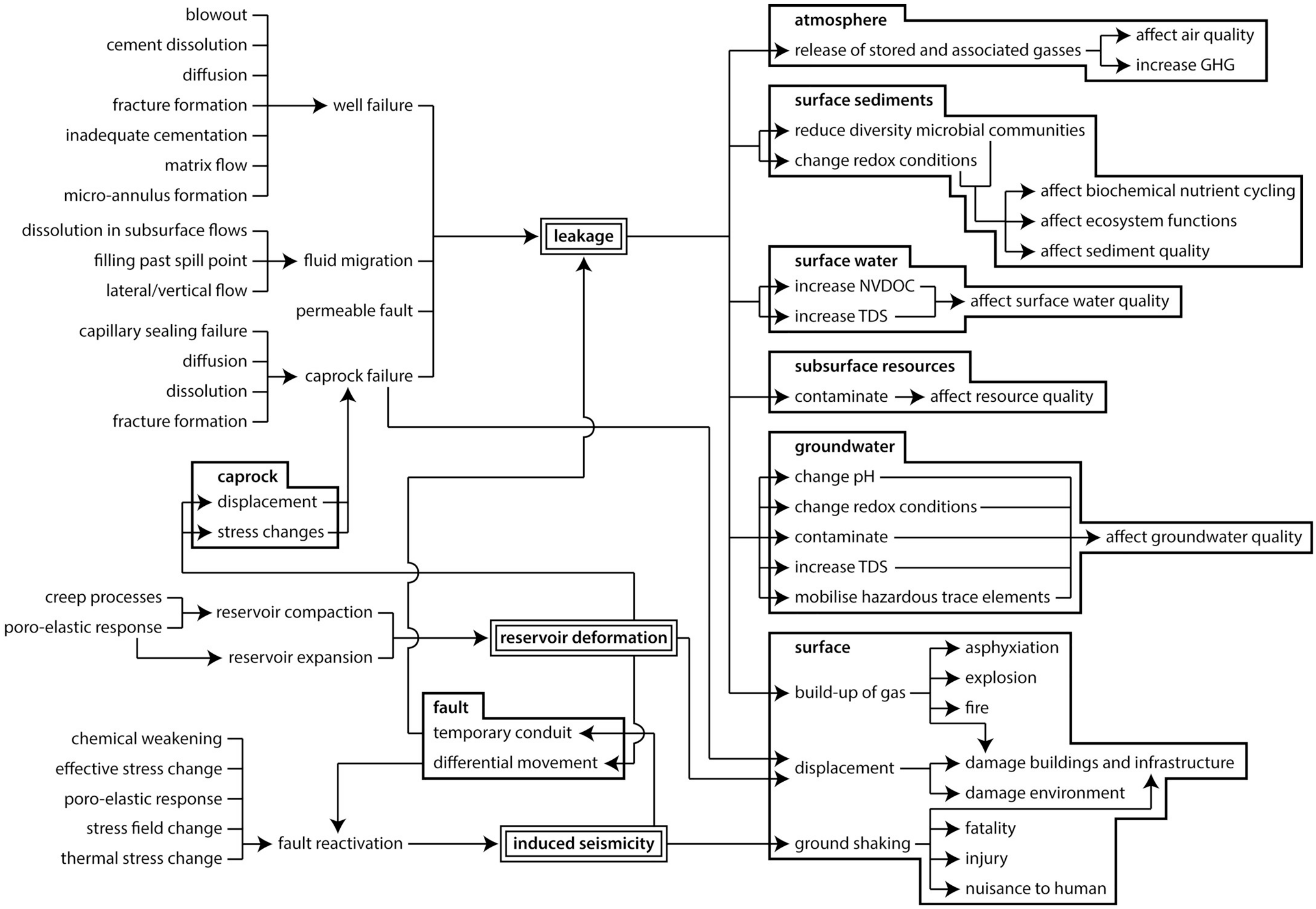

Fig. 1. Logic tree of fluid injection into a hydrocarbon reservoir. The centre of the map contains the major hazards (double-lined box). On the left, the causes leading to a hazard are presented, and on the right, the consequence that could result from a hazard. The consequences are grouped per receptor (single-lined box). The black arrows connect underlying causes to main causes, to hazards, to primary and secondary consequences.

1000 years, respectively, which is a small fraction of the total injected fluid (250 million tonnes) (Pawar et al., 2016). Indirect leakage, where the leaked fluid first arrives at a shallow aquifer and subsequently migrates to the atmosphere, leads to 0.5 ppm CO_2 release over 50 years (Viswanathan et al., 2008).

3.2.2. For the surface environment

Fluids that leak from the storage reservoir can reach the surface and affect *surface sediments* by changing the redox conditions and the microbial communities living in the sediment (wastewater literature; Table 4; Fig. 1). Investigation of sediment quality upstream, downstream and adjacent to a wastewater injection site revealed that the adjacent and downstream locations were marked by elevated Fe(III) concentration that indicated a change in redox conditions, while this was lacking in the upstream locations (Akob et al., 2016). In addition, the microbial diversity was reduced in these sediments. These changes affected the sediment quality and its function in the biochemical nutrient cycling and ecosystem.

As a result of leakage, fluid injected can emerge in *surface waters* (wastewater literature; Table 4; Fig. 1). As introduced before, the analysis of surface waters upstream, downstream and adjacent to a wastewater injection site established that several changes occurred in the adjacent and downstream water compared to upstream (Akob et al., 2016). An increase in non-volatile dissolved organic carbon (NVDOC) was observed and the total dissolved solids (TDS) increased from 100 µs/cm to 400 µs/cm. Elevated concentration of inorganic constituents were observed, e.g. total iron concentration increased from 0.13 mg/L to 8.1 mg/L, while the lithium concentration was six times the background value. These consequences affected the surface water quality.

In addition, leaked fluids (especially gaseous phases) can impact the *surface infrastructure* when they build-up in confined places (methane literature; Table 2; Fig. 1). Studies on methane reported several consequences due to methane build-up, including asphyxiation, explosion or sudden fire, or degradation of geotechnical properties of soil foundations by gas pressure build-up (Baciu et al., 2008; Schout et al., 2017).

3.2.3. For the subsurface environment

Escaped injected fluids can migrate to *subsurface resources*, such as other hydrocarbon reservoirs or mineral deposits (CO_2 literature; Table 1; Fig. 1). In case of mixing between the leaked fluid and resources, the contaminated resources need to be cleaned, introducing extra costs (Oldenburg et al., 2011).

The quality of *groundwater* can be severely affected through mixing with fluids leaked from a storage reservoir. The consequences of leakage for groundwater includes contamination, changed pH and redox conditions, increased TDS and mobilised hazardous trace elements (CO_2, methane and wastewater literature, Tables 1, 2 and 4; Fig. 1). Methane contamination was found in a drinking water aquifer after a subsurface well blowout (Schout et al., 2017). The highest methane concentrations were found next to the blowout area, which exceeded the recommended hazard threshold (10 mg/L). While upgradient little thermogenic methane was encountered, the methane had spread downgradient up to 515 m. Similarly, gaseous CO_2 intruded into an aquifer dissolves and migrates primarily along the groundwater flow direction (Apps et al., 2010).

Dissolution of CO_2 in groundwater increases the TDS, e.g. from 600 mg/L to 1500 mg/L (Zheng et al., 2012), however, the effect strongly depends on aquifer thickness (Viswanathan et al., 2008). In addition, CO_2 dissolution reduces the pH from 7.6 to 5.7–5.9 (Apps et al., 2010), below 6.5 (Pawar et al., 2016) or from 7.0 to 5.5–6 (Zheng et al., 2012), promoting the release hazardous trace elements, such as lead (Pb) and arsenic (As) (Apps et al., 2010; Zheng et al., 2012). Intrusion of methane, on the other hand, causes a slight increase in pH (Schout et al., 2017).

3.3. Causes for reservoir deformation

3.3.1. Reservoir compaction

Reservoir compaction occurs during reservoir depletion and is therefore not expected in a storage operation. An exception is methane, because methane is both stored and produced in the subsurface. Pore pressure reduction causes the reservoir rock to contract, reducing the horizontal stresses within the reservoir, i.e. poro-elastic response (Table 3; Fig. 1). The magnitude of the stress changes depends on the magnitude of the pore pressure change and the reservoir characteristics. For instance, a pore pressure reduction of 1.8 MPa can result in an average decrease of 1.3 MPa in the absolute horizontal stress, which is about 75% of the pore pressure change (Tenthorey et al., 2013). Simultaneous reservoir contraction in the vertical direction would result in approximately 12 mm downward movement of the top of the reservoir, where the displacement accumulates (Tenthorey et al., 2013).

In addition, pore pressure reduction increases the effective stress acting on the reservoir rock according to Terzaghi's law (Terzaghi, 1943). Such increase activates grain-scale deformation processes, causing elastic and permanent compaction of the reservoir. Some of these processes are instantaneous (time-independent), while others develop with time (time-dependent). Time-dependent (creep) processes, such as pressure solution (Dewers and Hajash, 1995; Gratier et al., 2009; Schutjens, 1991; Spiers et al., 2004) and sub-critical crack growth (Brantut et al., 2012; Brzesowsky et al., 2014), can have a strong contribution to the total amount of compaction, because creep can cause compaction of the reservoir long after production has ceased.

3.3.2. Reservoir expansion

Reservoir repressurisation can lead to reservoir expansion (CO_2 and methane literature; Tables 1 and 2; Fig. 1). Due to the poro-elastic expansion of the reservoir rock, the horizontal stresses increase. Methane injection leading to a pore pressure increase of 0.58 MPa was accompanied by an average increase of 0.45 MPa of the absolute horizontal stresses, which is approximately 75% of the pore pressure change (Tenthorey et al., 2013). Simultaneous vertical expansion of the reservoir rock resulted in a vertical displacement of the top of the reservoir of approximately 4 mm (Tenthorey et al., 2013). CO_2 injection into a different hydrocarbon reservoir, leading to a pore pressure increase of 3.3 MPa, moved the reservoir top 19 mm upwards close to the injection well, where the maximum displacement was modelled (Karimnezhad et al., 2014). The majority of the changes (63% of total displacement) occurred in the first year of injection. The vertical displacement per pore pressure change due to CO_2 injection (5.8 mm/MPa) is in the same order of magnitude compared to methane injection (8.9 mm/MPa).

3.4. Consequences of reservoir deformation

3.4.1. For the surface environment

At the *surface*, reservoir deformation can cause surface displacement in both the vertical and horizontal direction (CO_2, methane and wastewater literature, Tables 1, 2 and 4; Fig. 1). Surface displacement potentially damages buildings, infrastructures and the environment (Ferronato et al., 2010; Teatini et al., 2011a). The vertical displacement follows the extracted or stored volume in the reservoir, while the horizontal displacement depends on the location with respect to the centre of gravity of the field. For instance, a point west of the centre of gravity of the field moves eastwards when a fluid is extracted from the reservoir and westwards when a fluid is injected. Surface subsidence is in many cases observed during field depletion. During injection, surface subsidence is only partially recovered, because reservoir compaction is not fully elastic (Ferronato et al., 2010; Teatini et al., 2011a; Tenthorey et al., 2013). To illustrate, in one case study (Ferronato et al., 2010), an elliptical subsidence bowl of approximately 2 by 1 km with a maximum depth of 160 mm above the centre of gravity of the field developed by the end of production. Injection of CO_2 to > 140% of the initial pore pressure resulted in a maximum uplift of 80 mm, only half of the original subsidence.

Alternatively, surface displacement can be a consequence of caprock deformation (wastewater literature; Table 4; Fig. 1). Wastewater injection with subsequent dissolution of the halite caprock would result in a subsidence bowl of 5 km in diameter with a maximum depth of 120–140 mm (NAM, 2016c). The deepest point was located above the crest of the injection reservoir, where dissolution was most severe.

3.4.2. For the subsurface environment

In response to reservoir deformation, the reservoir-caprock interface moves, which could lead to failure of the *caprock* via stress changes in the caprock that could induce tensile or shear failure (Karimnezhad et al., 2014; Tenthorey et al., 2013) (CO_2 and methane literature; Tables 1 and 2; Fig. 1). In addition, reservoir deformation can result in *fault* reactivation (Fig. 1). Differential deformation of the reservoir, due to heterogeneous reservoir characteristics and non-uniform pore pressure changes within the reservoir, can cause unequal displacement along a fault, resulting in a net fault slip and potentially inducing seismicity (Nagelhout and Roest, 1997).

3.5. Causes for induced seismicity

3.5.1. Fault reactivation

Induced seismicity refers to earthquakes related to human activity, such as the extraction or injection of fluids in the subsurface (Suckale, 2010). Fault rupture and slip along the fault plane generate seismic waves, perceived at the surface as an earthquake. Fault reactivation occurs when the shear stress (τ_s) acting on a fault satisfies the Mohr-Coulomb failure criterion:

$$\tau_s \geq c + (\sigma_n - P_p)\tan\phi \tag{1}$$

where σ_n is the normal stress, P_p the pore pressure, c cohesion and ϕ friction angle. The magnitude of the shear and normal stress depend on the magnitude of the in situ principle stresses and the orientation of the fault with respect to this stress field. Cohesion and friction angle are fault specific properties. Injection can change the failure criterion parameters via multiple mechanisms, i.e. effective stress change, poro-elastic response, stress field change, thermal stress and chemical weakening (CO_2, methane, nitrogen and wastewater literature; Tables 1-4; Fig. 1).

Injection increases the reservoir pore pressure, which decreases the effective vertical and horizontal stresses in the reservoir. Simultaneously, injection invokes a poro-elastic response of the reservoir and the absolute horizontal stresses increase with a fraction of the pore pressure change. This is known as the reservoir stress path, which is site specific. The effective vertical stress decreases by the same amount as the pore pressure change, while the reduction in effective horizontal stresses is partly compensated by the increase in the absolute horizontal stresses. To illustrate, for a stress path of 0.75, a 10 MPa pore pressure increase would raise the horizontal stress with 7.5 MPa. Simultaneously, the effective stress decreases with 10 MPa, resulting in

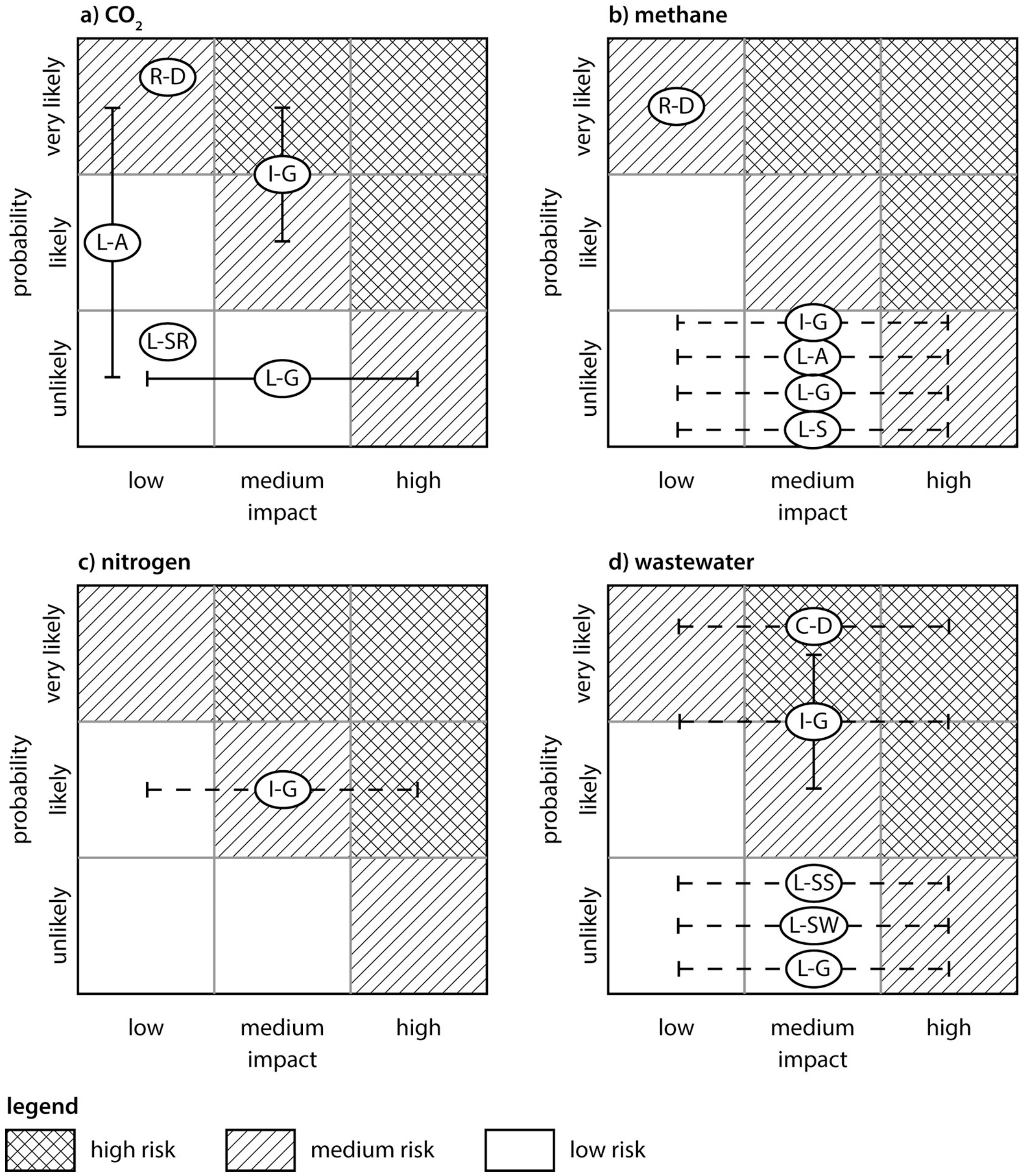

Fig. 2. A qualitative probability-impact diagram indicating the level of risks for nine hazard-receptor combinations based on reviewing the selected literature. Error bars indicate the lack of knowledge (dashed line) or the spread of knowledge in current studies (solid line). Hazard-receptor combinations that plot in the same quadrant are placed randomly; no further division is made. The following hazard-receptor combinations are presented L-A: leakage to atmosphere; L-SS: leakage to surface sediments; L-SW: leakage to surface water; L-SR: leakage to subsurface resources; L-G: leakage to groundwater; L-S: leakage to surface; C-D: caprock failure with surface displacement; R-D: reservoir deformation with surface displacement; I-G: induced seismicity with ground shaking.

a net reduction of the effective horizontal stress of 2.5 MPa. The effective vertical stress is reduced by 10 MPa. This changes the shear and normal stress acting on a fault, creating a potentially unstable situation (Eq. 1) (NAM, 2016a, 2016b; Pijnenburg et al., 2018; TNO, 2015).

In a worst case scenario, the pore pressure increase reduces the effective stress without increasing the absolute stress, such that only the normal stress acting on the fault is lowered. This could occur in a fault that is partly embedded in the reservoir and partly in the caprock, such that the caprock fault section would be reactivated (NAM, 2016b; TNO, 2015). Alternatively, pore pressure changes can be transmitted over large distances (> 1 km) via permeable fractures and fault zones where they invoke only changes in the effective stress, leading to fault reactivation in case of critically stress faults (Goebel et al., 2016).

In some cases, injection alters the local stress field. Injection can lead to large-scale, non-uniform pore pressure changes within the reservoir, resulting in stress-arching (TNO, 2015). In addition, earthquakes can transfer small stresses, large enough to reactivate critically stressed faults (NAM, 2016b). Thus, the occurrence of one earthquake due to fluid injection can trigger more seismicity. Moreover, mass changes due to the removal or addition of large masses within the earth or on the surface can affect the local stress field (NAM, 2016b).

Injection of a relatively cold fluid into the reservoir gradually cools the reservoir in the vicinity of the injection wells. In the affected area, cooling causes the reservoir rock to contract and induces thermal stresses. These stresses affect areas beyond the area of cooling. Due to thermal contraction of the reservoir rock, the normal stress acting on any nearby fault reduces and the shear stress increases, destabilising the fault. Fault stability depends on the induced temperature change and the initial stress state in the reservoir (NAM, 2016b; Orlic et al., 2013; TNO, 2015).

During injection, a fault initially saturated with hydrocarbons gets wetted by the injection fluid. This change in chemical environment could affect fault strength and lead to fault reactivation (NAM, 2016b).

3.6. *Consequences of induced seismicity*

3.6.1. *For the surface environment*

The seismic waves produced during an earthquake cause ground shaking upon reaching the earth's *surface*. Ground shaking can be a nuisance to humans, damage buildings and infrastructures, and result in injury or fatality (CO_2, nitrogen and wastewater literature; Tables 1, 3 and 4; Fig. 1). The size of an earthquake is commonly expressed in moment magnitude (M_w) (e.g. NAM, 2016b). However, the M_w metric provides limited information on the earthquake impact at the surface, as it does not describe the amount of energy reaching the surface. Alternative metrics are peak ground acceleration (PGA) and peak ground velocity (PGV). Specifically PGV is used in the design of seismic intensity scales for human disturbances and damage to vulnerable houses. An earthquake originating at 1 km depth with a moment magnitude of 2.5–3 can result in a PGV of 20–30 mm/s at the surface within a few hundred meters from the fault. Further away from the fault ($>$ 1 km) the PGV decays to 2.5 mm/s (Rutqvist et al., 2014).

3.6.2. *For the subsurface environment*

During fault reactivation, a normally sealing *fault* can form a temporary conduit for fluid flow parallel or perpendicular to the fault plane. Many studies (CO_2 and methane injection; Tables 1 and 3) described the possibility for fluids to escape the storage reservoir during fault reactivation, but none analysed this scenario by, e.g., examining the volumes that could escape during reactivation.

4. Risks of fluid injection

The logic tree (Fig. 1) shows that each hazard can affect multiple receptors. Using values derived from the selected literature the risk, defined as the product of probability and impact, could be determined for each hazard-receptor combination. Qualitative risk labels (low, medium and high) were used, because often 1) probabilities and impacts were reported in non-conformable metrics; 2) assumptions and reported results were site specific; 3) presented results were qualitative; and 4) the applied method for sampling the literature does not allow for a robust statistical analysis. The results are presented in a probability-impact diagram (Fig. 2).

4.1. *Leakage to the environment*

4.1.1. *To the atmosphere*

The risk of leakage to the atmosphere was investigated in the literature on CO_2 and methane injection. In the CO_2 literature, leakage via well failure was assessed as unlikely (Oldenburg et al., 2011). However, leakage through an open wellbore (a worst-case scenario) would definitely result in CO_2 release to the atmosphere (Pawar et al., 2016). The other pathways for CO_2 leakage, caprock failure via diffusion or fracture formation, were considered improbable (Oldenburg et al., 2011; Tambach et al., 2015) or did not occur at all when modelled (Ferronato et al., 2010; Karimnezhad et al., 2014; Soltanzadeh and Hawkes, 2012). Combining these reported probabilities, the probability for CO_2 leakage ranges from unlikely to very likely. The impact of leakage to the atmosphere was considered low, because the volume of escaped CO_2 was well below the set thresholds (Pawar et al., 2016; Viswanathan et al., 2008). Based on these values, the risk for CO_2 leakage to the atmosphere is low to medium (Fig. 2a).

For methane leakage to the atmosphere, a failure probability, regardless of the failure mechanism, was calculated for regular oil and gas wells in Pennsylvania of 0.73–5.21% (Ingraffea et al., 2014). In addition, a relatively low frequency (~1:1000) for uncontrollable well blowout during operation was reported (Schout et al., 2017). Leakage via a naturally permeable fault was found to be site specific (Baciu et al., 2008; Tang et al., 2013) meaning that a probability cannot be set. The probability for caprock failure was also deemed unlikely, because fracture formation did not occur (Khaksar et al., 2012). Thus, the overall probability of leakage is unlikely. The impact ranges from low to high, because the impact of released methane and associated gasses was not assessed. Therefore, the methane leakage risk to the atmosphere is low to medium (Fig. 2b).

4.1.2. *To surface sediments*

In the wastewater literature, probabilities of leakage via fluid migration and caprock failure were found to be negligible (probability of 10^{-47}) (Andričević et al., 2009) and unlikely (NAM, 2016c), respectively. However, these results were not specifically for leakage from the reservoir to surface sediments. The impact of leakage to surface sediment was investigated, but not compared to thresholds (Akob et al., 2016). Consequently, the impact level is unknown. The resulting risk is low or medium (Fig. 2d).

4.1.3. *To surface water*

In the literature on wastewater injection, the probability of leakage was assessed as unlikely (Andričević et al., 2009; NAM, 2016c). Though the impact of leakage to surface water was investigated, results were not compared with thresholds (Akob et al., 2016). Due to a lack of impact level, the risk is low or medium (Fig. 2d).

4.1.4. *To subsurface resources*

Leakage to subsurface resources was analysed in the literature on CO_2. The probability of CO_2 leakage was modelled in multiple studies and was found to be unlikely (Ferronato et al., 2010; Karimnezhad et al., 2014; Oldenburg et al., 2011; Soltanzadeh and Hawkes, 2012; Tambach et al., 2015). The impact of CO_2 leakage on subsurface resources was considered as low (Oldenburg et al., 2011). The risk is therefore low (Fig. 2a).

4.1.5. *To groundwater*

The risk of leakage to the groundwater was investigated in the literature on CO_2, methane and wastewater. In the CO_2 literature, the probability of leakage was found to be unlikely (Ferronato et al., 2010; Karimnezhad et al., 2014; Oldenburg et al., 2011; Soltanzadeh and Hawkes, 2012; Tambach et al., 2015). The different impacts of CO_2 leakage to groundwater were analysed in a number of studies and were found to range from low to high. The impact of contamination was low, because the volume of escaped CO_2 that arrived at the aquifer was small compared to the total amount injected and well below the set threshold (Viswanathan et al., 2008). However, CO_2 dissolution significantly reduced groundwater pH with 1.5–2.9 pH point (Apps et al., 2010; Zheng et al., 2012). Though this effect is large, no pH thresholds were defined and an impact level cannot be selected. The modelled TDS increase was close but below the MCL (Viswanathan et al., 2008; Zheng et al., 2012), while it exceeded the MCL in case of a thin aquifer (Viswanathan et al., 2008). Therefore, the impact ranges medium to high. The impact of mobilisation of trace metals is medium, because lead and arsenic concentrations approached the MCL (Apps et al., 2010; Zheng et al., 2012). Combining the probability of CO_2 leakage to groundwater and the various impacts, the risk is low to medium (Fig. 2a).In the literature on methane injection, the occurrence of leakage was found to be unlikely (Ingraffea et al., 2014; Khaksar et al., 2012; Schout et al., 2017). The impact of contamination is high, because a wellbore blowout resulted in methane concentrations above the recommend threshold (Schout et al., 2017). Changes in pH and redox conditions were also found, though the impact was not quantified (Schout et al., 2017). The risk of methane leakage to groundwater is low to medium (Fig. 2b).

The probability that injected wastewater would reach an overlying aquifer was determined to be unlikely (10^{-47}) (Andričević et al., 2009).

Wastewater leakage via caprock failure was also found to be unlikely (NAM, 2016c). The impact of leakage on groundwater was not assessed in the wastewater literature. The risk of wastewater leakage to groundwater is low or medium (Fig. 2d).

4.1.6. *To the surface*

In the literature on methane injection, leakage in general was considered as unlikely (Ingraffea et al., 2014; Khaksar et al., 2012; Schout et al., 2017). Two studies found that faults could form conduits for methane escape and measured significant fluxes (Baciu et al., 2008; Tang et al., 2013). However, the impact of methane build-up at the surface was not assessed. Therefore, the risk of methane leakage to the surface is low to medium (Fig. 2b).

4.2. *Caprock failure with surface displacement*

Caprock failure via dissolution was found to occur in wastewater injection (NAM, 2016c) and the probability of very likely is assigned. Modelled caprock failure resulted in 12–14 cm surface subsidence (NAM, 2016c). However, the surface subsidence was not compared to thresholds and no impact level can be assigned. The risk of caprock failure with surface displacement is medium to high (Fig. 2d).

4.3. *Reservoir deformation with surface displacement*

Reservoir deformation with surface displacement was considered in the literature on CO_2 and methane injection. Based on the CO_2 injection literature, the probability of reservoir deformation was assessed as very likely, because reservoir expansion was found to occur (Ferronato et al., 2010; Karimnezhad et al., 2014). The impact is considered low, because injection resulted in a net surface uplift of 8 cm and a displacement gradient below set thresholds (Ferronato et al., 2010). The resulting risk is medium (Fig. 2a).

In the literature on methane injection, reservoir deformation via both compaction and expansion was found to occur (Teatini et al., 2011a; Tenthorey et al., 2013). The probability is thus very likely. The impact is low, because the resulting displacement gradients were well below the set limits (Teatini et al., 2011a). The risk of reservoir deformation with surface displacement due to methane injection is medium (Fig. 2b).

4.4. *Induced seismicity with ground shaking*

Induced seismicity was the focus in literature on each injection fluid. All CO_2 studies on induced seismicity found that fault reactivation would occur during CO_2 injection (Ayash et al., 2009; Ferronato et al., 2010; Rutqvist et al., 2014; Soltanzadeh and Hawkes, 2012). Where one study predicted the occurrence of 6×10^4 fracture events (Ayash et al., 2009), another found that two out of the four major faults would slip (Ferronato et al., 2010). In one study, pore pressures were intentionally increased to induce fault slip (Rutqvist et al., 2014). This would not occur in an actual injection operation. The probability of seismicity therefore ranges from likely to very likely. The impact of an earthquake was found to be largest close to the fault, where high PGV's were modelled and the maximum impact was perceivable light shaking and cosmetic damage to buildings (Rutqvist et al., 2014). Thus, the impact of seismicity is medium. Combining probability and impact, the risk of induced seismicity with ground shaking for CO_2 injection is medium to high (Fig. 2a).

In the methane injection literature, none of the studies found that induced seismicity would occur during injection (Khaksar et al., 2012; Orlic et al., 2013; Tenthorey et al., 2013). In one study, fault reactivation did occur during initial depletion of the reservoir, but the fault stabilised during injection (Orlic et al., 2013). Therefore, the probability for induced seismicity is unlikely. The impact of seismicity was not assessed in the studies on methane injection and ranges from low to high. The risk for induced seismicity with ground shaking is low or medium (Fig. 2b).

The nitrogen injection literature recognised a wide range of mechanisms for fault reactivation (NAM, 2016a; TNO, 2015). With most mechanisms unlikely to cause fault slip and some likely, the probability is likely. Potentially consequences of ground shaking were identified, but not assessed. Therefore, the impact extends from low to high. The risk of induced seismicity with ground shaking due to nitrogen injection is low to high (Fig. 2c).

The wastewater literature also identified various mechanisms for fault reactivation. While some were only relevant for areas with critically stressed faults, others were likely or very likely to cause induced seismicity (Goebel et al., 2016; NAM, 2016b). In addition, spatio-temporal analysis of injection wells and earthquakes revealed that approximately 8% of the wells used for EOR in central and eastern United States could be associated with seismicity (Weingarten et al., 2015). Ground shaking was recognised as a consequence, but no impact assessment was made. With a possible impact ranging from low to high, the risk also ranges from low to high (Fig. 2d).

5. Risk assessment approaches

5.1. *Risk assessment stages*

A risk assessment typically consists of five stages, including site characterisation, hazard analysis, consequence assessment, probability assessment, and risk and uncertainty characterisation (Gormley et al., 2011). Each stage is characterised by several steps (Table 5).

In *stage I*, site characterisation, the system is defined in both space and time. This was done by all 28 studies. Most studies (25) identified sources, events and processes that may cause and control a hazard, such that a first order conceptual model could be developed. Controversially, few studies (6) formulated appropriate measures of risk and corresponding thresholds. These thresholds could be used at a later stage to evaluate the outcome of the risk assessment (Stage V). In *stage II*, hazard analysis, hazards were identified by all studies (28), of which 23 studies analysed the mechanism of hazard occurrence, hazard pathways and potential consequence receptors. The three studies that did not include this step made basic assumptions about hazard occurrence and spread, to solely focus on the consequences. Subsequently, 19 studies constructed scenarios, linking specific hazards, pathways and receptors, which can be used for consequence or probability assessment. In *stage III*, consequence assessment, the consequences of a particular hazard were identified by 25 studies, while only 19 evaluated the corresponding magnitude. Some studies made worst-case scenario assumptions and combined this with site specific parameters to evaluate the consequence magnitude, e.g. the maximum expected seismic moment (NAM, 2016b; Rutqvist et al., 2014), surface subsidence (Ferronato et al., 2010; NAM, 2016c; Teatini et al., 2011a; Tenthorey et al., 2013), and the effect of a small and uncontrolled (non-remediated) leakage on groundwater quality (Akob et al., 2016; Apps et al., 2010; Schout et al., 2017; Viswanathan et al., 2008; Zheng et al., 2012). In *stage IV*, probability assessment, the probabilities of hazard occurrence (19 studies), hazard exposure (four studies) and hazard vulnerability (zero studies) were assessed. Hazard exposure is concerned with the spatial and temporal spread of the hazard, while it depends on the vulnerability of the receptor, the vigour of the hazard, and the amount or extent of exposure whether the receptor is affected by the hazard. In *stage V*, risk and uncertainty characterisation, six studies combined the probabilities of stage IV with the consequences identified in stage III to compare them with the risk limits set in stage I. In addition, 14 studies performed a sensitivity analysis to address uncertainty in the overall assessment and to gain further understanding of the mechanisms or to characterise the uncertainty in the results.

Table 5
Risk assessment stages and research focus of the selected studies.

Assessment stage and action description	CO_2		Methane		Nitrogen		Wastewater	
	Study	# 11	Study	# 9	Study	# 2	Study	# 6
Stage I – Site characterisation								
Define the system	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11	11	12, 13, 14, 15, 16, 17, 18, 19, 20	9	21, 22	2	23, 24, 25, 26, 27, 28	6
Identify sources, events and processes which may cause and control a hazard	2, 3, 4, 5, 6, 7, 8, 9, 10	9	12, 13, 14, 15, 16, 17, 18, 19, 20	9	21, 22	2	23, 25, 26, 27, 28	5
Identify appropriate measures of risk and corresponding risk threshold	3, 5, 6, 7, 10	5	18	1	–	0	–	0
Stage II – Hazard analysis								
Identify hazards	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11	11	12, 13, 14, 15, 16, 17, 18, 19, 20	9	21, 22	2	23, 24, 25, 26, 27, 28	6
Analyse the mechanism of hazard occurrence, pathways of hazard spread and consequence receptors	1, 3, 4, 5, 6, 7, 8, 9, 10, 11	10	12, 13, 14, 15, 16, 18, 19	7	21, 22	2	24, 25, 26, 27	4
Form scenarios according to hazards, pathways/mechanisms and receptors	3, 4, 5, 6, 7, 8, 10	7	12, 13, 14, 16, 17, 18, 19	7	21	1	24, 25, 26, 27	4
Stage III – Consequence assessment								
Identify the consequences	1, 2, 3, 4, 5, 6, 7, 8, 10, 11	10	12, 13, 14, 16, 17, 18, 19, 20	8	21	1	23, 24, 25, 26, 27, 28	6
Evaluate the magnitude of the consequences	1, 3, 5, 6, 7, 10, 11	7	12, 16, 17, 18, 19	5	–	0	23, 24, 26, 27	4
Stage IV – Probability assessment								
Evaluate the probability of a hazard occurring	2, 3, 4, 5, 6, 7, 8, 9, 10	9	13, 14, 15, 18, 19	5	21, 22	2	26, 27, 28	3
Evaluate the probability of exposure to a hazard	10	1	16	1	–	0	23, 24	2
Evaluate the probability of the receptors being affected by a hazard	–	0	–	0	–	0	–	0
Stage V – Risk and uncertainty characterisation								
Combine the evaluated consequences and probabilities and compare them with risk limits	3, 5, 6, 7, 10	5	18	1	–	0	–	0
Evaluate sensitivity of results to changes in parameters to gain further understanding	1, 4, 6, 7, 8, 9, 11	7	14, 15	2	22	1	24, 25, 27, 28	4

Note 1. (Apps et al., 2010); 2. (Ayash et al., 2009); 3. (Ferronato et al., 2010); 4. (Karimnezhad et al., 2014); 5. (Oldenburg et al., 2011); 6. (Pawar et al., 2016); 7. (Rutqvist et al., 2014); 8. (Soltanzadeh and Hawkes, 2012); 9. (Tambach et al., 2015); 10. (Viswanathan et al., 2008); 11. (Zheng et al., 2012); 12. (Baciu et al., 2008); 13. (Khaksar et al., 2012); 14. (Ingraffea et al., 2014); 15. (Orlic et al., 2013); 16. (Schout et al., 2017); 17. (Tang et al., 2013); 18. (Teatini et al., 2011a); 19. (Tenthorey et al., 2013); 20. (Zheng et al., 2017); 21. (NAM, 2016a); 22. (TNO, 2015); 23. (Akob et al., 2016); 24. (Andričević et al., 2009); 25. (Goebel et al., 2016); 26. (NAM, 2016b); 27. (NAM, 2016c); 28. (Weingarten et al., 2015).

5.2. *Assessment methods*

The mechanism of *hazard occurrence* and *the pathways of hazard spread* were mostly modelled (22 studies) and in some cases interpreted from field experiments (four studies). 3D flow models were used to model the flow of the injected fluid in the target reservoir (Andričević et al., 2009; Ferronato et al., 2010; Goebel et al., 2016; Karimnezhad et al., 2014; NAM, 2016c; Oldenburg et al., 2011; Orlic et al., 2013; Rutqvist et al., 2014; Tambach et al., 2015; Teatini et al., 2011a; TNO, 2015) or the spread of a leakage in an overlying aquifer (Apps et al., 2010; Zheng et al., 2012). As a subsequent step to modelling flow in the reservoir, 3D geomechanical modelling was used to determine the resulting stress changes in the reservoir and surrounding rock. This was done to evaluate whether the Mohr-Coulomb criterion for fault reactivation (eq. 1) was satisfied (Goebel et al., 2016; Khaksar et al., 2012; NAM, 2016a, 2016b; Orlic et al., 2013; Rutqvist et al., 2014; Soltanzadeh and Hawkes, 2012; Tenthorey et al., 2013; TNO, 2015; Zheng et al., 2017), shear or tensile fracturing occurred (Khaksar et al., 2012; Oldenburg et al., 2011; Soltanzadeh and Hawkes, 2012; Zheng et al., 2017), or to determine the amount of reservoir deformation and accompanying surface displacement (Khaksar et al., 2012; NAM, 2016c; Teatini et al., 2011a). Field studies involved measuring natural or accidental leakage around fault systems or wells (Baciu et al., 2008; Schout et al., 2017; Tang et al., 2013), analysing historic wellbore leakage data (Ingraffea et al., 2014), or performing spatiotemporal analysis on historical earthquake and injection data to correlate seismicity and fluid injection (Weingarten et al., 2015).

Consequence and *probability assessment* was done using the same models (14 studies) or field studies (five studies). In most modelling studies (10), the magnitude of the consequence was assessed deterministic, using site specific input parameters that represent the most likely scenario. However, some worst-case scenario assumptions were usually included as well, such as a constant, non-remediated leakage into an aquifer (Apps et al., 2010), the presence of cohesionless faults with optimal orientation for reactivation (Ferronato et al., 2010; Khaksar et al., 2012; NAM, 2016b; Orlic et al., 2013; Zheng et al., 2017) or negligible slow mineral reactions (Tambach et al., 2015). In five modelling studies (Andričević et al., 2009; Ayash et al., 2009; Pawar et al., 2016; Soltanzadeh and Hawkes, 2012; Viswanathan et al., 2008), model input parameters were varied using Monte Carlo simulation to represent parameter uncertainty and to determine probabilities. Probability density functions (pdf's) were defined for uncertain site-specific parameters, including fracture angle inclination (Ayash et al., 2009; Soltanzadeh and Hawkes, 2012), reservoir characteristics such as depth, porosity, permeability, elastic constants and friction properties (Andričević et al., 2009; Pawar et al., 2016; Soltanzadeh and Hawkes, 2012), well characteristics such permeability via various leakage pathways (Viswanathan et al., 2008) and the stress field in and around the reservoir (Soltanzadeh and Hawkes, 2012). Pdf's were presented by a Cauchy distribution (Ayash et al., 2009), normal distribution (Soltanzadeh and Hawkes, 2012) or log-normal distribution (Viswanathan et al., 2008) and for some parameters these distributions were truncated.

5.3. *Assessment parameters*

Frequently reported parameters included site location, assessment period, injection rate and volume, and reservoir pore pressure. Most studies were site-specific or use a synthetic site that was loosely based on specific location (Tambach et al., 2015; TNO, 2015; Viswanathan

Table 6
Injection parameters.

Study	Country	Assessment period [y]	Injection rate per well		Total injected volume		Relative injection pressure [%]
			[kg/d]	[Sm^3/d]	[kg]	[Sm^3]	
CO_2							
1	US	100	–	–	–	–	–
2	US	–	–	477	–	–	–
3	IT	150		1.7×10^5	–	1.0×10^{10}	115
4	IR	10	2.7×10^4	–	1.0×10^8	–	109
5	DZ	30	6.8×10^5	–	2.2×10^{10}	–	–
6	US	200/1000	5.0×10^4	–	3.6×10^8	–	–
7	–	0.1	–	–	–	–	175
8	CA	–	–	–	–	–	252
9	NL	1000	2.8×10^6	–	1.1×10^{10}	–	100
10	US	50	4.3×10^6	–	7.9×10^{10}	–	–
11	US	–	–	–	–	–	–
Methane							
12	RO	–	–	–	–	–	–
13	AU	–	–	–	–	–	115
14	US	12	–	–	–	–	–
15	NL	50	–	–	–	–	60
16	NL	–	–	–	–	–	–
17	CN	–	–	–	–	–	–
18	IT	32	–	5.1×10^5	–	7.7×10^{10}	120
19	AU	15	–	4.8×10^4	–	1.7×10^{10}	107
20	CN	7	–	5.2×10^5	–	1.1×10^8	100
Nitrogen							
21	NL	–	–	–	–	–	34
22	NL	20	–	3.5×10^6	–	2.6×10^{10}	46
Wastewater							
23	US	–	–	1.5×10^4	–	1.8×10^5	–
24	HR	100/10,000	–	30	–	2.2×10^5	–
25	US	0.8	–	1.1×10^3	–	6.6×10^5	–
26	NL	–	–	2.5×10^3	–	–	89
27	NL	1000	–	4.0×10^3	–	2.9×10^7	–
28	US	41	–	–	–	–	–

Note 1 (Apps et al., 2010); 2. (Ayash et al., 2009); 3. (Ferronato et al., 2010); 4. (Karimnezhad et al., 2014); 5. (Oldenburg et al., 2011); 6. (Pawar et al., 2016); 7. (Rutqvist et al., 2014); 8. (Soltanzadeh and Hawkes, 2012); 9. (Tambach et al., 2015); 10. (Viswanathan et al., 2008); 11. (Zheng et al., 2012); 12. (Baciu et al., 2008); 13. (Khaksar et al., 2012); 14. (Ingraffea et al., 2014); 15. (Orlic et al., 2013); 16. (Schout et al., 2017); 17. (Tang et al., 2013); 18. (Teatini et al., 2011a); 19. (Tenthorey et al., 2013); 20. (Zheng et al., 2017); 21. (NAM, 2016a); 22. (TNO, 2015); 23. (Akob et al., 2016); 24. (Andričević et al., 2009); 25. (Goebel et al., 2016); 26. (NAM, 2016b); 27. (NAM, 2016c); 28. (Weingarten et al., 2015); AU: Australia; CA: Canada; CN: China; DZ: Algeria; HR: Croatia; IR: Iran; IT: Italy; NL: Netherlands; RO: Romania; US: United States.

et al., 2008). One study (Rutqvist et al., 2014) did not use site-specific parameters, though the input values were considered realistic. Site locations in the selected studies were distributed around the globe with at least one study per continent, except for South America (Table 6). Three studies focussed on locations in Asia (Karimnezhad et al., 2014; Tang et al., 2013; Zheng et al., 2017), one in Africa (Oldenburg et al., 2011), ten in North America (Akob et al., 2016; Apps et al., 2010; Ayash et al., 2009; Goebel et al., 2016; Ingraffea et al., 2014; Pawar et al., 2016; Soltanzadeh and Hawkes, 2012; Viswanathan et al., 2008; Weingarten et al., 2015; Zheng et al., 2012), eleven in Europe (Andričević et al., 2009; Baciu et al., 2008; Ferronato et al., 2010; NAM, 2016a, 2016b, 2016c; Orlic et al., 2013; Schout et al., 2017; Tambach et al., 2015; Teatini et al., 2011a; TNO, 2015) and two in Australia (Khaksar et al., 2012; Tenthorey et al., 2013).

The risk assessment studies applied a range of assessment periods, varying between 40 days to 10,000 years. Short assessment periods were employed by two studies on induced seismicity. One study intentionally induced fault slip after 40 days of injection to evaluate the (time-independent) consequences (Rutqvist et al., 2014). The other reproduced seismicity observed around an injection well over a 300 day period (Goebel et al., 2016). Ten studies (Ingraffea et al., 2014; Karimnezhad et al., 2014; Oldenburg et al., 2011; Orlic et al., 2013; Teatini et al., 2011a; Tenthorey et al., 2013; TNO, 2015; Viswanathan et al., 2008; Weingarten et al., 2015; Zheng et al., 2017) evaluated the injection period without subsequent storage and adopted assessment periods between 7 and 50 years. Several of these studies (Orlic et al., 2013; Teatini et al., 2011a; Tenthorey et al., 2013; Zheng et al., 2017) investigated the temporary storage of methane. Studies that did include the storage period used modelling times between 100 and 200 years (Andričević et al., 2009; Apps et al., 2010; Ferronato et al., 2010; Pawar et al., 2016), 1000 years (NAM, 2016c; Pawar et al., 2016) or even 10,000 years (Andričević et al., 2009; Tambach et al., 2015). Multiple studies also considered the time period before injection started. In some cases, geomechanical models used for forecasting were validated by reproducing past observed reservoir pore pressure (Ferronato et al., 2010; Tenthorey et al., 2013), ground motion above the reservoir (Teatini et al., 2011a) or seismicity in the area (Orlic et al., 2013), or past seismicity was used as a guideline for probability evaluation (Ayash et al., 2009; NAM, 2016b).

Injection rates were reported in 16 site specific studies, though different units were units, including units representing mass per time, such as Mt./y, kg/s and kg/d, and volume per time, like Sm^3/d, Sm^3/y, m^3/d and m^3/mo. Expressing the injection rate in mass per time was preferred in the studies on CO_2 injection, while studies on the other injection fluids employed volume per time units. It is not straight forward to compare the different units, as density of the fluids were not always reported, neither were the pressure and temperature at which the volume was determined. Recalculating the reported injection rates to either kg/d or Sm^3/d per one injection well, resulted in the following ranges 2.7×10^4–4.3×10^6 kg/d and 30–3.5×10^6 Sm^3/d (Table 6).

Taking into account the number of injection wells (ranging 1–30) and the duration of injection (between 40 days and 58 years), fluid masses of 1.0×10^8 - 7.9×10^{10} kg and fluid volumes of 2.2×10^5 - 7.7×10^{10} Sm^3 were injected in total (Table 6).

Reservoir pore pressures were reported in 13 studies. According to several studies, the maximum safe pore pressure is the initial reservoir pore pressure, i.e. the reservoir pore pressure before depletion (NAM, 2016a, 2016b). As pore pressures are site-specific, the injection pore pressure is reported as a percentage of the initial pore pressure (Table 6). Two studies employed a low relative pressure of 34% and 46% of the original pore pressure (NAM, 2016a; TNO, 2015) and four studies operated injection pressures close or equal to the initial pressure with relative pore pressure of 60%, 89%, or 100% (NAM, 2016b; Orlic et al., 2013; Tambach et al., 2015; Zheng et al., 2017), thereby heeding the concept that the injection pressure should remain below or equal to the initial pressure. On the other hand, seven studies exceeded the original pore pressure to investigate if the injection pressure can be safely increased beyond the original pressure. This resulted in pore pressures varying between 107 and 252% of the initial pore pressure (Ferronato et al., 2010; Karimnezhad et al., 2014; Khaksar et al., 2012; Rutqvist et al., 2014; Soltanzadeh and Hawkes, 2012; Teatini et al., 2011b; Tenthorey et al., 2013). The largest relative pore pressure was adopted Soltanzadeh and Hawkes, 2012 to investigate the pressure change needed to reactive an optimally oriented fault, which occurred at 177–187% (90% confidence interval) of the original pore pressure.

6. Lessons learned and knowledge gaps

6.1. Comparison of the identified hazards

The logic tree (Fig. 1) is largely derived from the literature on CO_2 and methane injection. The look-up tables for CO_2 (Table 1) and methane (Table 2) show a strong similarity in the described hazards, causes, receptors and consequences. This contrasts with the literature on nitrogen and wastewater (Tables 3 and 4), which reported less hazards and a smaller number of causes and consequences. The difference in look-up tables may be caused by the number of studies selected per fluid. The small number of studies on nitrogen and wastewater resulted in a narrow focus on a small selection of hazards, causes and consequences. However, the literature on nitrogen and wastewater injection added unique elements to the logic tree. Literature on both fluids reported in detail on the underlying causes of fault reactivation, providing more clarity on the complexity of induced seismicity. Furthermore, the wastewater injection literature recognised a new pathway from caprock deformation to surface displacement and described two receptors (surface water and sediments) that were not recognised in any of the other literature.

6.2. Comparison of the risks

For the selected literature on all fluids, there was a relatively strong consensus on the probability of a hazard occurring, while there was a large spread in the impact on the receptor (Fig. 2). The spread in impact is in some cases, e.g. leakage of CO_2 to groundwater, because a hazard can cause multiple consequences within a receptor and each consequence can have a different severity. In other cases, the spread is because the magnitude of the consequence is not assessed (e.g. methane and wastewater leakage to groundwater, methane leakage to the atmosphere and surface, and induced seismicity with ground shaking due to methane, nitrogen or wastewater injection) or compared to thresholds (e.g. wastewater leakage to surface water and sediment, and caprock deformation with surface displacement due to wastewater injection).

Four out of nine hazard-receptor combinations were evaluated for different injection fluids and can be compared (Fig. 2). The risk of leakage to the atmosphere was considered in the literature on CO_2 and methane injection and though the same risk levels were assigned (low to medium), the probability and impact differed (c.f. Fig. 2a and b). The probability of CO_2 leakage was found to vary between unlikely and very likely, while the probability of methane leakage was considered as unlikely. This difference is due to one study on CO_2 injection that modelled leakage through an open wellbore and found that leakage occurred in all simulations (Pawar et al., 2016). All other studies on both CO_2 and methane injection concluded that the proposed leakage pathways were unlikely (Ferronato et al., 2010; Ingraffea et al., 2014; Karimnezhad et al., 2014; Khaksar et al., 2012; Oldenburg et al., 2011; Schout et al., 2017; Soltanzadeh and Hawkes, 2012; Tambach et al., 2015). The impact of CO_2 leakage to the atmosphere was considered as low, while no consequence assessment of methane leakage was made.

The risk of leakage to groundwater was evaluated in the CO_2, methane and wastewater literature, and for all fluids the risk ranked between low and medium (Fig. 2a, b and d). The probability was assessed as unlikely for all fluids. The impact for CO_2, methane and wastewater infiltration ranged between low and high. The range in wastewater impact was due to a lack of consequence assessment. For CO_2 leakage, the impact levels were well established, because consequence magnitudes were determined and compared to thresholds. This was partly done for the consequences of methane leakage.

The risk of reservoir deformation with surface displacement was investigated in the literature on CO_2 and methane injection. For both fluids, the risk ranked medium, because of a low impact and very likely probability (Fig. 2a and b). There was a strong consensus on this topic in the examined literature.

The risk of induced seismicity with ground shaking was examined in the literature on all injection fluids and the risk ranges from low to high (Fig. 2). There is no agreement on the probability of occurrence. Both the studies on CO_2 and wastewater ranked the probability between likely and very likely, while the nitrogen literature considered it to be likely, and the methane literature unlikely. The impact was not categorised in the methane, nitrogen and wastewater literature, because no consequence assessment was made. In the CO_2 literature, the severity of damage to buildings and nuisance to humans was examined, which resulted in a medium impact.

6.3. Comparison of the assessment approaches

Analysis of the risk assessment stages indicates there is a strong focus on defining the system, identifying hazards and consequences, and understanding the hazards (Table 5). A large number of studies defined pathways between hazard causes and consequences for specific receptors, while some studies analysed the spread of hazard, however, limited studies evaluated the related probability. Insufficient knowledge is observed on the potential pathways of hazard spread, such as transport of hazardous agents from the point-of-release to a receptor. Moreover, none of studies assessed the probability of a receptor being affected by a hazard, which could indicate that the vulnerability of the receptor, the potency of the hazard and the amount or extent of exposure are not yet well understood.

In addition, few studies identified appropriate measures of risk and corresponding risk thresholds (Table 5). Some thresholds were applied, such as the threshold for the maximum displacement gradients for masonry buildings and steel and concrete (Ferronato et al., 2010; Teatini et al., 2011a), or the PGV metric that could be compared to intensity scales for human disturbances and damage to buildings (Rutqvist et al., 2014). However, such thresholds were not applied by the majority of the studies. This could indicate a lack of awareness on available thresholds. In other cases, investigators were forced to use hypothetical limits because standards were lacking (Pawar et al., 2016; Viswanathan et al., 2008). It indicates the need for publicly available, standardised thresholds.

In the risk assessments, there is a large uncertainty in many site specific parameters, including the in situ stress field, and number and location of wells and faults. The uncertainty in these parameters is related to a lack of knowledge of the deep subsurface. Another class of uncertain parameters are reservoir characteristics such as depth, porosity, permeability, elastic constants and friction properties. The uncertain parameters were not the same for all studies and also the parameter uncertainty varied, which is connected to the variation in the amount and quality of available data on the subsurface and reservoir characteristics. The risk assessment studies applied worst-case scenarios or pdf's to deal with this uncertainly or lack of knowledge.

A large spread in modelling time was found for the different risk assessments (Table 6). The choice of modelling time strongly depends on the objective of the study. Several studies evaluated the injection period and adopted relatively short assessment periods (7–50 years). While others modelled the subsequent storage period and used modelling times between 100 and 10,000 years. The modelling time of 100 or 200 years is considered short for the purpose of permanent storage, which has timescales of at least 1000 years. The differences in injection rates and volumes for the different risk assessment (Table 6) were mainly related to site-specific parameters, such as reservoir size and permeability, number of wells, and targeted reservoir pore pressure.

6.4. Validation by expert workshop

The logic tree was presented during the expert workshop. The overall structure of the map was approved and several elements were added. These include differential movement across a fault resulting from reservoir deformation, creep processes that cause reservoir compaction and loss of life due to ground shaking at the surface.

6.5. Bridging the knowledge gaps and future studies

Table 7 provides an overview of identified knowledge gaps. The literature on CO_2 and methane injection provided the most complete overview of the hazards of fluid injection. However, details in underlying causes for well failure, fluid migration, caprock failure, reservoir compaction and fault reactivation, and consequences of leakage to surface water, sediment and groundwater, and consequences of induced seismicity were missing. These were partly supplemented by the literature on nitrogen and wastewater injection, and partly by the expert workshop. However, a thorough understanding of hazard causes and consequences is lacking and several steps can be taken to improve the current knowledge base. For example, consequences of leakage can be better understood by analysing natural analogue sites (e.g. Espinoza et al., 2018; Fessenden et al., 2009). While knowledge on hazard causes can be further developed by incorporating laboratory experiments on, for instance, the effect of temperature and pore fluid chemistry on fault behaviour (e.g. Hunfeld et al., 2017; Pluymakers et al., 2014; Verberne et al., 2013) or on the strength of reservoir rocks (e.g. Baud et al., 2000; Brantut et al., 2013; Hangx et al., 2013; Rohmer et al., 2016). However, it should be noted that it remains challenging to upscale laboratory results to the field scale (Spiers et al., 2017).

Analysis of the risks of specific hazard-receptor combinations revealed that for most fluids probabilities for hazard occurrence were defined, while there is a large uncertainty in the impact of hazards (Table 7). This is uncertainty is due to a lack of knowledge on hazard exposure and receptor affectability. Incorporation of exposure and vulnerability models would reduce the uncertainty in impact. To illustrate, models are available to assess the impact of seismicity on buildings that take into account the extent of built area and the vulnerability of the buildings (Gunasekera et al., 2015). Specific knowledge gaps for CO_2 injection are the potential consequences of leakage to surface water and surface sediments, and the consequences of leakage to groundwater. For methane injection, there is a lack of knowledge on the impact of leakage on the atmosphere, groundwater, and surface and on the impact of ground shaking. Though induced seismicity was the main focus in the literature on nitrogen injection, there is a lack of knowledge on the impact of ground shaking. In the literature on wastewater injection, more research is needed on the impact of leakage to surface water, sediments and groundwater, and on the impact of caprock deformation and ground shaking.

Several knowledge gaps can also be identified based on the assessment approaches (Table 7). In the risk assessment of all fluids, appropriate thresholds were lacking or not applied, probabilities of hazard exposure and receptor affectability were not determined, and site specific parameters were unknown or uncertain. In addition, in the methane literature there was a lack of understanding on parameter

Table 7
Summary of key knowledge gaps.

Fluid	Hazards	Risks	Assessment approaches
CO_2	• Lack of knowledge on underlying causes of well failure, fluid migration, caprock failure, reservoir compaction and fault reactivation • Lack of knowledge on consequences of leakage and induced seismicity	• Lack of knowledge on hazard exposure • Lack of knowledge on receptor affectability • Lack of knowledge on impact of leakage to surface water, sediments and groundwater	• Appropriate thresholds are missing and use of available thresholds is limited • Uncertainty in site specific parameters
Methane	• Lack of knowledge on underlying causes of well failure, fluid migration, caprock failure, reservoir compaction and fault reactivation • Lack of knowledge on consequences of leakage and induced seismicity	• Lack of knowledge on hazard exposure • Lack of knowledge on receptor affectability • Lack of knowledge on impact of leakage on surface water, sediments and groundwater, and impact of ground shaking	• Appropriate thresholds are missing and use of available thresholds is limited • Lack of understanding parameter sensitivity • Uncertainty in site specific parameters
Nitrogen	• Hazards of leakage and reservoir deformation are not reported, including causes and consequences	• Lack of knowledge on consequence magnitude • Lack of knowledge on hazard exposure • Lack of knowledge on receptor affectability • Lack of knowledge on impact of ground shaking	• Appropriate thresholds are missing and use of available thresholds is limited • Uncertainty in site specific parameters
Wastewater	• Hazard of reservoir deformation is not reported, including causes and consequences • Lack of knowledge on causes of well failure and caprock failure	• Lack of knowledge on hazard occurrence • Lack of knowledge on hazard exposure • Lack of knowledge on receptor affectability • Lack of knowledge on impact of leakage to surface water, sediments and groundwater, and impact of caprock deformation and ground shaking	• Appropriate thresholds are missing and use of available thresholds is limited • Uncertainty in site specific parameters

sensitivity. While in the nitrogen assessments there was insufficient knowledge of hazard consequences and associated magnitudes. Wastewater risk assessments were lacking knowledge on hazard occurrence.

Current studies on the environmental and geological risks of fluid injection into hydrocarbon reservoirs primarily focus on individual hazards and risks. However, hazards may occur simultaneously affecting the same or different receptors, or one hazard may trigger another hazard (Fig. 1). This requires combining exposure and vulnerability models to understand the cumulative impact of hazards on a receptor. In addition, there is a need for research on cumulative probabilities, incorporating the occurrence of multiple hazards. Therefore, a holistic multi-hazard approach is recommended as one of the directions for future studies. Coarse multi-hazard frameworks are available (e.g. Gill and Malamud, 2017), but detailed frameworks for site-specific analysis are needed. These frameworks also need to account for the large amount of complex, multidisciplinary data, which is characterised by high levels of uncertainty and subjective to interpretation. To avoid biases, these risk assessment frameworks must be systematic and transparent, and follow predefined assessment schemes (Milkov, 2015).

In addition, researchers should be aware that both positive and negative biases can be introduced in a risk assessment. For example, incorrect upscaling of rock properties, especially those that are strongly heterogeneous at the reservoir scale, may introduce positive biases (Burnside and Naylor, 2014; Deng et al., 2012). This may result in an underestimation of the actual risk. On the other hand, historical analysis of field cases published in the literature may lead to a bias towards hazard occurrences with a large impact, while these are generally rare, which affects the probability estimate. Moreover, the societal perception of risk can greatly differ from the technical risk (Merz et al., 2009). This may lead to risk limits that are too strict, which may impede the development of subsurface injection activities.

Geo-energy technologies play an indispensable role in the sustainable energy transition. Geothermal heat and electricity will probably have an increasing share in the future energy mix (Hussain et al., 2017; Shortall et al., 2015). Subsurface energy storage, e.g. underground hydrogen storage, compressed air energy storage, is essential in facilitating renewable energy integration (Blanco and Faaij, 2018). The lessons learned and identified knowledge gaps in this work are also applicable to these geo-energy technologies and facilitate the decision-making process in designing and implementing strategies and policies with less environmental impacts. However, implementation geo-energy technologies also require analysis of the operational and economic risks, which have not been addressed in this study.

7. Conclusion

Natural gas, a low-carbon alternative to coal and oil, contributes to the sustainable energy transition. However, production-induced reservoir compaction causes induced seismicity and surface subsidence, raising the concern for sustainable production of natural gas. Injection of fluids into the reservoir can potentially mitigate reservoir compaction and has been applied worldwide. However, fluid injection is not free of environmental impacts. Many studies have been carried out to assess its environmental and geological risks. There is a need for having general lessons learned so far and how current knowledge can be applied to future geo-energy technologies. The objective of this study is to generate a qualitative overview on the environmental and geological risks of fluid injection into hydrocarbon reservoirs and further provide insights on lessons learned and potential knowledge gaps. This was done by reviewing 28 studies that examined the risks of injecting CO_2 (eleven studies), methane (nine studies), nitrogen (two studies) or wastewater (six studies). The process of the review focussed on analysing hazards, categorizing risk levels and evaluating assessment approaches.

Based on reviewing the selected literature, the main hazards of fluid injection are leakage, reservoir deformation and induced seismicity. The main causes are identified as well failure, fluid migration, permeable fault, caprock failure, reservoir compaction and expansion, as well as fault reactivation. The hazards can affect impact receptors of atmosphere, the surface environment, e.g. surface sediments and surface water, as well as the subsurface environment, e.g. subsurface resources and groundwater. The input for the general logic tree of fluid injection was largely derived from the literature on CO_2 and methane injection. Information on some underlying causes, such as the mechanisms for fault reactivation, and new consequence receptors (surface water and sediments) originated from the literature on nitrogen and wastewater injection.

The logic tree explicitly showed the existence of nine hazard-receptor combinations. For these combinations a risk level (defined as the product of probability and impact) was determined using qualitative terms based on the occurrence probabilities and consequence magnitudes reported in the literature selected for reviewing. For most hazard-receptor combinations the probability was well defined, while there was a large spread in impact due to either the existing spread in severity of the potential consequences or a lack of knowledge on consequence impacts. Four hazard-receptor combinations were evaluated for multiple injection fluids. The risk of leakage to the atmosphere was equal for CO_2 and methane, though the underlying probability and impact differed. The probability of leakage to groundwater was independent of the type of fluid injected (CO_2, methane and wastewater), though there was a large spread in impact level. Identical risk levels were found for reservoir deformation with surface displacement due to either CO_2 or methane injection. Lastly, induced seismicity with ground shaking was assessed for all four fluids. There was no consensus on probability and in most cases, except CO_2, the impact was unknown, because a consequence assessment was lacking.

The reviewed studies followed the five stages typically present in a risk assessment, i.e. site characterisation, hazard analysis, consequence assessment, probability assessment, and risk and uncertainty characterisation. However, for all fluids there was a strong focus on the first three stages, specifically on defining the system, identifying and analysing hazards and identifying consequences. The risk assessments on the injection of more mature fluids, i.e. CO_2 and methane, also evaluated consequence magnitudes and probabilities. In the assessments, there was uncertainty in site specific parameters and a large range of modelling times was used. The choice of modelling time depended on which stages of injection were involved in the study.

Combining the literature on fluid injection, there is an extensive overview of the hazards, however, knowledge on well failure, fluid migration, caprock failure, reservoir compaction and fault reactivation is lacking. In addition, the consequences and impact of leakage and induced seismicity are not yet fully appraised, which is due to a lack of consequence assessments. Moreover, appropriate risk thresholds are not always available and assessment results are seldom evaluated against available thresholds. This calls for more research on fundamentally understanding hazards occurrence, hazard exposure and receptor affectability. Furthermore, there is a need to further investigate the probability of multiple hazards occurrence and the corresponding cumulative risks. Such research is also valuable for other injection operations, such as geothermal energy and underground energy storage, and will contribute to sustainable geo-energy resource utilisation.

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Appendix

Table A1
Participant overview.

Participant	Employed at	Expertise
1	Utrecht University	Geo-resources technology assessment
2	Utrecht University	Environmental risk analysis
3	Utrecht University	Rock mechanics
4	TNO	Reservoir mechanics
5	TNO	Subsurface risk analysis
6	Shell	Geophysics
7	Utrecht University	Rock mechanics
8	Taqa	Reservoir mechanics
9	Shell	Reservoir mechanics
10	Utrecht University	Energy system analysis

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