Stratigraphic reservoir compartmentalization: causes, recognition, and implications for the geological storage of carbon dioxide

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Abstract

The impact of carbon capture and storage (CCS) in mitigating anthropogenic emissions of greenhouse gases is potentially great, but its success is strongly dependent on identifying suitable geological storage sites. One of the key uncertainties in this regard is the degree of compartmentalization of the target storage horizon. Many studies have examined reservoir compartmentalization in oil and gas fields and its implications to hydrocarbon production, but few have looked at compartmentalization from the perspective of CCS storativity. Using case studies from the oil and gas industry, this paper examines the predictability of reservoir compartmentalization and the techniques used to assess it. It then focusses on stratigraphic compartmentalization in saline aquifers, a major category of potential carbon storage sites, examining in particular the Triassic Bunter Sandstone Formation of the UK North Sea. It is clear that the analysis of stratigraphic, seismic and fluid compositional data can provide early evidence of reservoir compartmentalization. The available data indicate that the Bunter Sandstone has a low risk of stratigraphic and structural compartmentalization. However, the presence of compartments in oil and gas fields is often confirmed only once well production data are available. As such, though the broad likelihood of compartmentalization in a CCS site can be forecasted, understanding its exact nature may be dependent on injection data.

Introduction

Carbon capture and storage (CCS) is the extraction, transport and geological trapping of carbon dioxide produced during the combustion of fossil fuels. It has been identified as a mechanism for generating cleaner energy from coal, oil and gas, and reducing pollution emitted by major industrial producers. The process typically involves the chemical removal of CO_2 from fossil fuel emissions, its compression into a supercritical fluid state, transport by underground pipeline, and injection into a permeable rock unit for permanent storage by mineralization.

One of the fundamentals of CCS viability is the identification of suitable geological reservoir intervals into which CO_2 can be injected and stored. It is critical that the target horizons are large, permeable, and structured such that physical or geochemical barriers trap the carbon dioxide in the pore waters, where it can mineralize. Saline aquifers – brine-filled permeable sedimentary rock formations – are of particular interest in this regard.

As geological reservoirs, saline aquifers may be ‘closed’ structures, in which geological barriers such as faults or impermeable lithologies prevent the upward (and lateral) migration of injected CO_2 out of the target storage interval. Examples of closed structures include four-way dip closures and fault-bounded reservoirs. Their integrity is dependent on the seal being able to withstand the pressure increase produced by the volume of carbon dioxide injected (see e.g. Mathias et al. 2009, 2011). Saline aquifers can occur additionally in open, tilted structures, with flow dynamics and viscosity controlling the retention of the CO_2 in the reservoir formation (Goater et al. 2013). Saline aquifers within large-scale closed structures tend to have greater storage efficiency, where a higher volume of is CO_2 is retained per unit of available pore space, but dipping open aquifers may offer greater total storage volumes (Goater et al. 2013).

Modelling techniques have also been used to argue that closed aquifers are not feasible as storage sites, due to <1% of the pore space being available for injected CO_2 storage before the reservoir pressure is exceeded (Ehlig-Economides & Economides 2010). Consequently, Ehlig-Economides & Economides (2010, p. 130) argued that reservoirs would either need to be “the size of a small US state” or require “hundreds” of injection wells. This interpretation has been contested by Chadwick et al. (2010, 2012) who questioned whether 'closed' reservoirs functioned as closed systems, and used data from the Sleipner CCS project in the Norwegian North Sea to show that, over more than a decade of operation, pressure increases were negligible. However, the reservoir permeability of Sleipner is unusually high, at around 5000 mD, more than three times greater than that of any of the other commercial CCS projects assessed by Hosa et al. (2011, fig. 4). Its injectivity (>1200 Darcy-metres) is also exceptional, although there is unlikely to be a clear correlation between reservoir transmissivity (formation thickness × permeability) and injection rate (Mathias et al. 2013). Non-geological factors such as plant design and economics can also play a key role in the injectivity of a storage horizon

(Hosa et al. 2011; Mathias et al. 2013). For large-scale injection and storage of CO_2 (>1 Mt per annum per well), therefore, considerable uncertainty remains about the optimal reservoir parameters.

In the UK, saline aquifers in the Bunter Sandstone Formation have been identified as some of the most prospective CO_2 storage targets (Holloway & Savage 1993, Holloway et al. 2006, Heinemann et al. 2012). Of Early Triassic age and sub-cropping much of the central and southern UK North Sea, the formation comprises fluvial, alluvial, aeolian and lacustrine sediments deposited in a semi-arid environment. Although their porosity can be reduced by halite cements (Laier & Nielsen 1989), the sandstone-dominated intervals of the formation have suitably high porosity and permeability and trapping mechanisms to hold large volumes of carbon dioxide, with Heinemann et al. (2012) estimating the formation storage capacity as 3.8–7.8 Gt. The potential reservoirs of the UK North Sea (Fig. 1) typically occur as four-way dip closures above basement highs or salt domes and, although fault-bounded, have low degrees of internal faulting. As such, there is a low probability that they are structurally compartmentalized; the main barriers and baffles to the flow of injected CO_2 are more likely to be stratigraphic. Determining the quantity of CO_2 that can be stored in these and other saline aquifers, however, is dependent upon accurate assessment of the risk and nature of compartmentalization within the reservoirs.

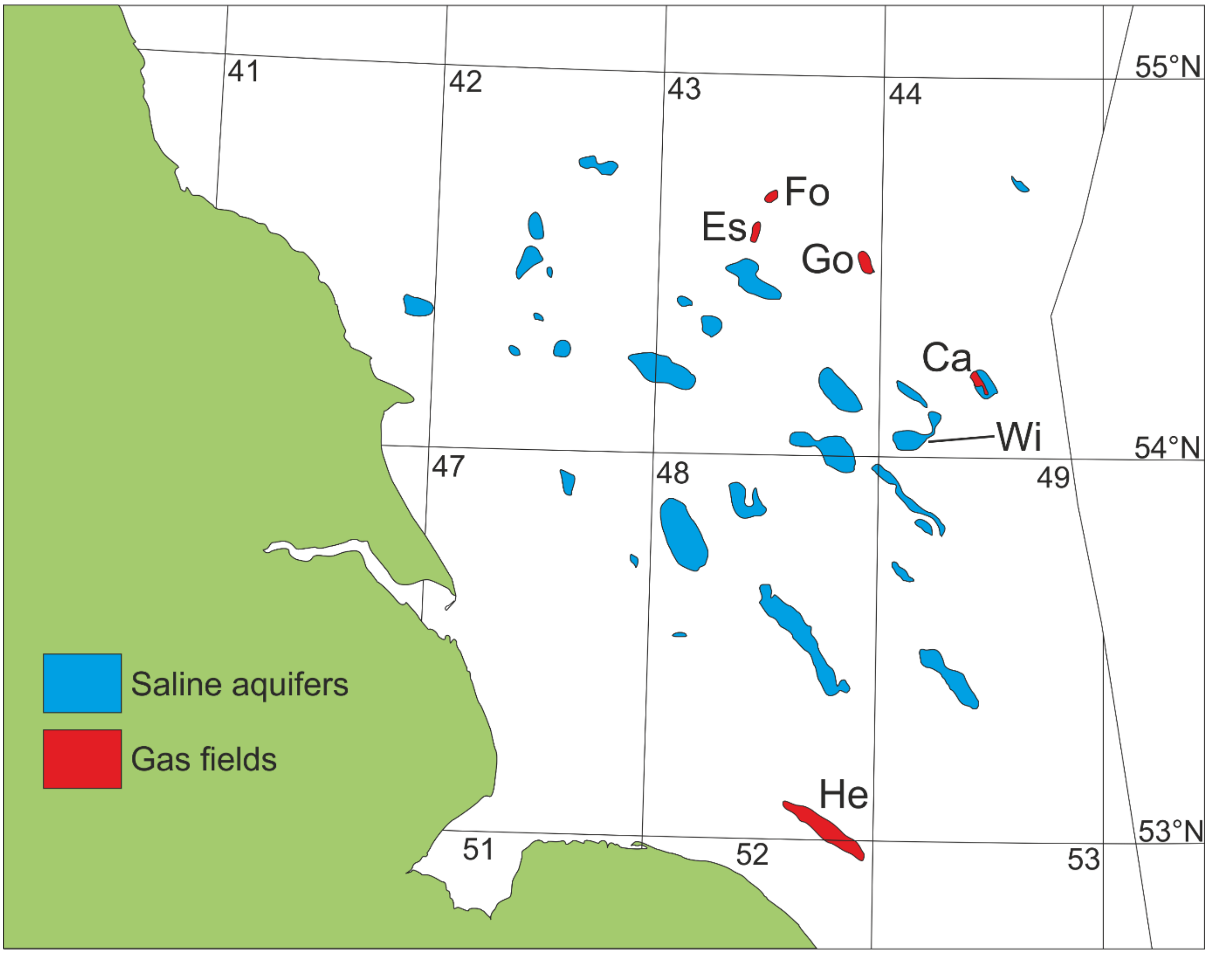

Figure 1. Map of licence blocks in UK Southern North Sea, showing locations of major domal reservoir structures in the Bunter Sandstone Formation (after Holloway *et al*., 2005). Saline aquifers shown in blue, gas fields in red. Abbreviations: Ca – Caister B; Es – Esmond; Fo – Forbes; Go – Gordon; He – Hewett; Wi – Williams *et al*. (2013) study area.

Compartmentalization is a concept derived from petroleum geology, in which a geological reservoir is subdivided into vertical or lateral segments, typically (but not exclusively) with different pressure or fluid properties. Compartmentalization is recognized when there is no communication of fluid flow between different parts of an oil or gas field over production time-scales. It is usually identified by a drop in well-head pressure and oil production rate, and by a rapidly rising gas-oil ratio.

Compartmentalization can be controlled by structural features, such as faults acting as barriers or baffles to flow; by stratigraphic variations in porosity and permeability; or by a combination of the two. As it can strongly affect the producible volumes of oil and gas, understanding the degree and nature of compartmentalization present within a reservoir is critical to a field's operational success.

A potential CO_2 storage horizon could be compromised if the reservoir interval is compartmentalized. However, this aspect has been little-considered from a CCS perspective, with structural compartmentalization in specific localities examined by only a small number of studies (Hovorka et al. 2011, Castelletto et al. 2013, Meckel et al. 2013). There is also limited experience of injecting CO_2 into saline aquifers, and many potential sites have a paucity of existing data (see e.g. Hedley et al. 2013). A broad review, utilizing exploration and production data from compartmentalized oil and gas fields, therefore has the potential to provide useful insights into the effects of reservoir compartmentalization on the storage of carbon dioxide in saline aquifers.

This report begins by giving an overview of the types of reservoir compartmentalization and their impacts upon oil and gas production. The recent review of reservoir compartmentalization in petroleum geology by Jolley et al. (2010) provides many relevant case studies and discussions of monitoring techniques. These show that for effective asset management, it is vital that compartmentalization is identified early, requiring the integration of different datasets, primarily seismic, sedimentological, and fluid data. Definitive proof of compartmentalization, however, typically comes from data that are not available prior to the start of production (Smalley and Muggeridge 2010). As such, the petroleum industry has developed various techniques and approaches to mitigate against the risk of late discovery of compartmentalization. These are discussed below.

The review then explores the likely importance of reservoir compartmentalization to the geological storage of CO_2. It examines stratigraphic compartmentalization in particular detail, with a focus on the

Bunter Sandstone saline aquifers of the UK North Sea and the potential impacts of stratigraphic heterogeneities on its storativity. From this, the risks of stratigraphic compartmentalization in the Bunter Sandstone are investigated, the importance to potential CO_2 storage sites are assessed and recommendations are made.

Reservoir compartmentalization

The connectivity of reservoir intervals is crucial to the success of a hydrocarbon field. If individual components of a reservoir are not connected, hydrocarbons in an isolated segment will not flow to a producing well in another segment during primary production or secondary, injection-driven recovery (Hovadik and Larue 2010). Compartmentalization is produced by geological heterogeneities that retard or prohibit the movement of fluids through a reservoir. A completely impermeable feature is referred to as a static seal or barrier, whilst a dynamic seal or baffle is one across which partial flow is possible (Jolley et al. 2010; Go et al. 2012). Three types of reservoir compartmentalization are recognized: structural, stratigraphic, and mixed-mode. In structural compartmentalization, faults partition the horizontal movement of fluids within the reservoir (Fig. 2A). Geometry and transmissibility are the most important factors (Irving et al. 2010); faults may be static barriers across which no flow is possible, or dynamic seals that act as baffles. The latter will still compartmentalize the reservoir, however, if the speed of transmissibility across them is slower than the production time scale.

Stratigraphic compartmentalization is generated by variations in the extent of impermeable lithologies, such as mudstones and salts, and tends to produce barriers to vertical fluid movement (Fig. 2B). Its magnitude is dependent on the net-to-gross (NTG) threshold and the reservoir dimensions (Hovadik and Larue 2010), with the importance of these factors being both reservoir-specific and time-dependent. Across different geological settings, NTG values of >60% are usually a strong indicator of reservoir connectivity (Hovadik and Larue 2010, fig. 5). However, as discussed below, this is dependent on the architecture of the permeable horizons and, as such, tends to be a function of the depositional setting. Furthermore, the existence of static reservoir connectivity within a field does not guarantee dynamic connectivity. As with faults, stratigraphic barriers can act as static or dynamic seals, and numerical modelling is required to evaluate the dynamic connectivity (Hovadik and Larue 2010).

Many reservoirs contain both faults and lateral and vertical variations in lithology, which combine to produce mixed-mode compartmentalization. In many mixed-mode fields, though, one type of compartmentalization will play a more dominant role than the other. In a case study of fields from offshore north-western Australia, for example, Ainsworth (2006) showed that there was a critical sealing fault density of 1.1 per km^2. Below this density, stratigraphic architecture controlled compartmentalization, whilst above it structural compartmentalization was the major control.

Across this variety of contexts, the meaning of compartment can be somewhat ambiguous. The term *drainage cell* was therefore used by Shepherd (2009) to describe situations where an orthogonal, intersecting fault system combines with stratigraphic barriers to create box-shaped reservoir intervals isolated by permeability barriers. However, Gill et al (2010) subsequently also applied the term to non-connected units within stratigraphically compartmentalized reservoirs.

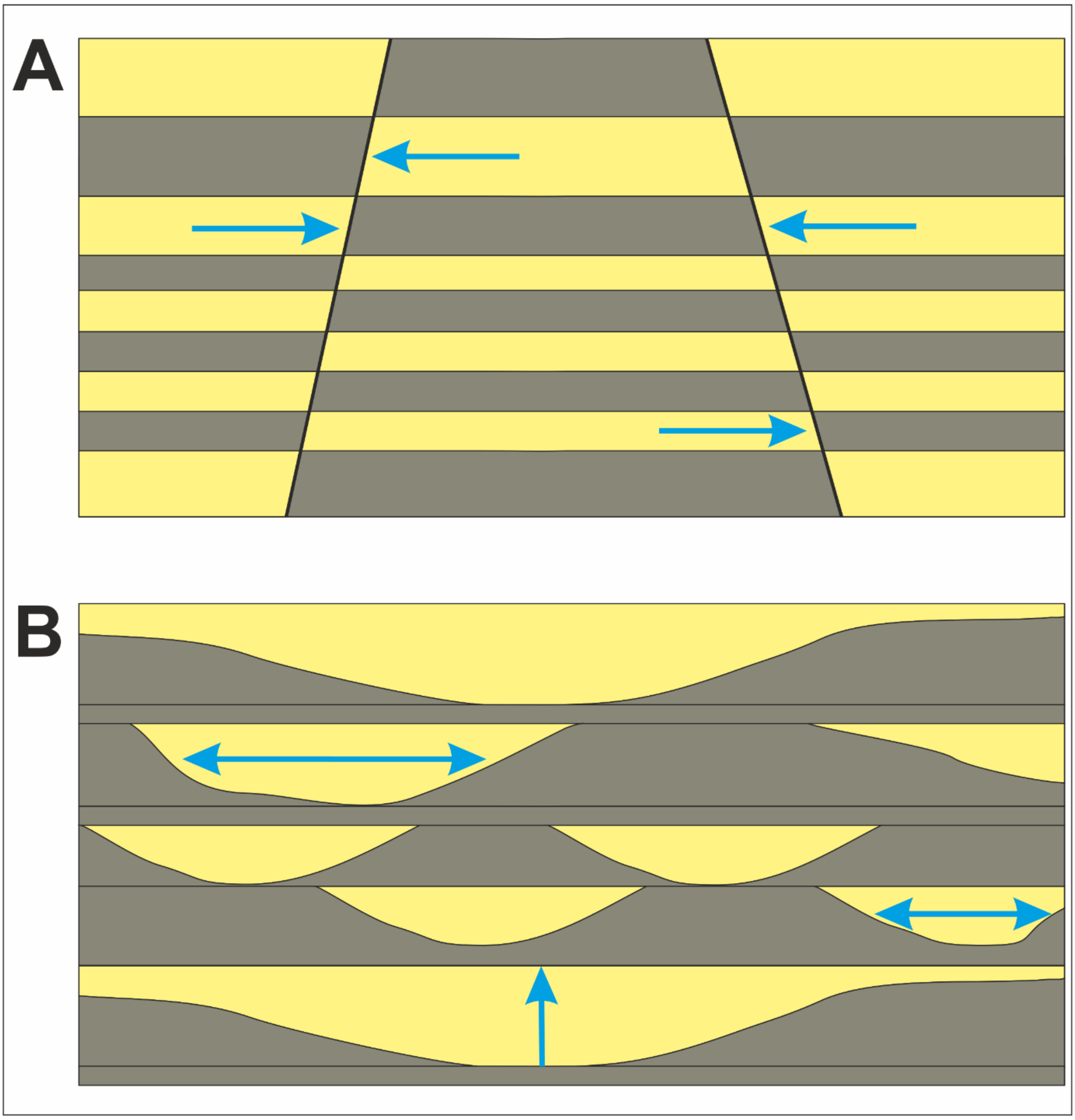

Figure 2. Schematic examples of reservoir compartmentalization types. A) structural compartmentalization of horizontally bedded succession of reservoir sandstones (yellow) and non-reservoir mudstones (grey), with normal faults creating barriers to horizontal fluid flow (blue arrows). B) stratigraphic compartmentalization of stacked succession of non-reservoir mudstones (grey) and channel sandstones (yellow), with channelization of reservoir sandstones into isolated bodies creating barriers to horizontal and vertical fluid flow (blue arrows).

Impacts of compartmentalization to the oil and gas industry

Recognizing compartmentalization within a reservoir is crucial to the economic viability of an oil or gas field; accurate estimates of reserve volumes dictate the field's value (Gluyas and Swarbrick 2004). The late recognition of compartmentalization will lead to increased costs, through having to spend longer collecting data before going into production, and reduced profitability from the realization that fewer hydrocarbons are retrievable (Jolley et al. 2010). If compartmentalization can be identified before a field goes into production, therefore, the economic impacts can be minimized.

In many cases, however, it is very difficult to confirm whether a reservoir is compartmentalized until a field begins producing, and dynamic pressure-time data can be analysed. In the UK North Sea, for example, numerous case studies discussed below show that reservoir compartmentalization has been 'systematically underestimated' (Smith 2008). As a consequence, various approaches have been developed to better quantify the risk and nature of reservoir compartmentalization.

Mitigation technologies and industry methods for estimating compartmentalization risk

Reservoir compartmentalization is assessed using a variety of techniques. These include the analysis of fluid properties, pressure-volume-temperature (PVT) data, and 3D or 4D seismic monitoring. For field-scale reservoir characterization, 3D seismic surveys use acoustic reflectivity to analyse subsurface geology and identify features indicative of compartmentalization. These include lithological changes, fault distributions, and fluid variations. By repeating such surveys over time, 4D seismic models can then be generated, enabling fluid movement and reservoir drainage to be assessed. Such analyses are key to confirming the existence and nature of reservoir compartmentalization, but are expensive and may therefore not be employed.

Well test data analysis, where the production behaviour of a well is examined, is a key method in evaluating potential compartmentalization. This approach focusses in particular on the flow rates of gas, oil and water over time as field production develops. Extended well testing over a duration of weeks to months is ideal, to obtain maximal information on hydrocarbon properties, reservoir structure and field behaviour. However, this can be economically or environmentally unfeasible (Gluyas and Swarbrick 2004). Regardless of the duration of the test, evaluating the subsequent behaviour of the reservoir is especially important. By the employment of pressure meters in the well, the post-test recovery of pressure in the well is analysed. These pressure build-up tests enable the natural restoration of pressure in the reservoir to be assessed, and potential flow barriers and baffles to be identified (Gluyas and Swarbrick 2004).

Within a single well, test data analysis may reveal indications that compartmentalization is present, but not its extent. To obtain more detailed information, an interference test may be carried out. In such analyses, a single well is placed into production or injection, whilst adjacent wells are shut in with pressure gauges installed (Gluyas and Swarbrick 2004). When production or injection commences in the test well, the subsequent pressure changes and durations can be determined in the surrounding wells, providing a much clearer picture of the reservoir structure and behaviour.

At the commencement of drilling, in order to provide the baseline field data on fluid characteristics and behaviour, pressure-volume-temperature (PVT) analysis must be carried out. Variations in PVT values from different wells within a field are a strong indicator of reservoir compartmentalization. However, Paez et al. (2010) showed that if the fluids are in a critical or near-critical state, they can be gravity segregated, such that wells within a connected reservoir might give different PVT values suggestive of compartmentalization.

A variety of other fluid properties can be analysed to examine potential compartmentalization, including chemistry, density, and viscosity. Though there is always a risk of water contamination, careful interrogation of produced fluid data is cheap and high-impact (Jolley et al. 2010). As with PVT data, if different wells or reservoir intervals show different fluid properties, the reservoir may be interpreted as compartmentalized. However, as shown by Smalley & Muggeridge (2010), it is vital to know the time required for the fluid property in question to equilibrate, along with the size and age of the reservoir.

The isotopic composition of reservoir pore fluids, for example, will equilibrate slowly across a reservoir. For a two million year-old reservoir, Smalley & Muggeridge (2010) calculated that hydrocarbon mixing by molecular diffusion would have occurred over a distance of less than 1 km. Even if clear differences in isotopic composition were measured within or between wells, this would not indicate the reservoir is compartmentalized. Conversely, aquifer pressure differences will equilibrate over 10 kilometres within 10 years (Smalley & Muggeridge 2010), so if differences in fluid pressure are detected within a new field, it is much more likely that the reservoir is compartmentalized.

Vertical and lateral variations in the chloride ions of produced water enabled Gill et al. (2010) to identify nine separate drainage cells in the Nelson field of the UK Central North Sea. These were controlled by stratigraphic compartmentalization by turbidite channel heterogeneity. Fluid analysis can also be employed to assess changes in reservoir compartmentalization. Time-lapse geochemistry – monitoring the composition of fluids during appraisal, development and production – was used in the Auger oil field in the Gulf of Mexico (Chuparova et al. 2010). The acquisition of pre-production fluid data provided the baseline by which changes in fluid composition could be measured. Collecting produced fluid samples was then a cheap means of detecting dynamic changes in reservoir communication. By assessing the ratio of oil to gas condensate it was shown that, after six years of production, an oil and a gas reservoir that static pressure data indicated were separate, were now in dynamic communication (Chuparova et al. 2010). Such early detection of changing reservoir behaviour can yield a significant benefit to the economics of a field.

An approach outlined by Richards et al. (2010) is Reservoir Connectivity Analysis (RCA), in which reservoir compartments are defined from seismic, pressure and fluid data, and the mechanical and capillary seal mechanisms between the compartments then evaluated. From this, the compartments and connections are mapped schematically to produce connectivity diagrams, enabling the compartmentalization of the reservoir to be assessed at different scales. Once production is underway, continuous data surveillance enables the models to be tested and confirmed as valid. As Jolley et al. (2010) state, compartmentalization may be suggested by various individual sources of data, but it is most reliably confirmed by early integration of diverse datasets and their subsequent monitoring.

Stratigraphic compartmentalization

The most important factor in stratigraphically compartmentalized reservoirs is the NTG threshold. The higher the NTG ratio of a field, the more likely it is that reservoir intervals are connected. Based on a variety of reservoir analyses, Hovadik and Larue (2010, p. 241) defined 60% as the level above which connectivity is 'unlikely to be a problem'. As shown in Figure 3, however, the stratigraphic architecture is important. In stacked, amalgamated channelized reservoir systems, NTG values of as low as 30% could still indicate good connectivity (Figure 3A; Hovadik and Larue 2010). In straight, parallel, channel systems (Figure 3B), NTG values of 60% are typically required, whilst in sheeted reservoirs (Fig. 3C), geobody connectivity will typically be low even when NTG values are >60% (Hovadik and Larue 2010). Other key elements to consider include reservoir dimensionality (e.g. the size and continuity of impermeable horizons) and the size of geobodies (connected reservoir units) when compared with that of the reservoir as a whole (Hovadik and Larue 2010). Mainly the environment the reservoir rocks were deposited in and their subsequent diagenetic history themselves control these factors.

Stratigraphic compartmentalization by depositional setting

The size, shape and properties of reservoirs within a target formation are dictated by the depositional conditions under which the succession formed. From terrestrial settings to deep marine basins, different sedimentary environments produce very different types of geobodies. As such, to predict the type of stratigraphic compartmentalization that might be present in a reservoir, the depositional environment must be evaluated.

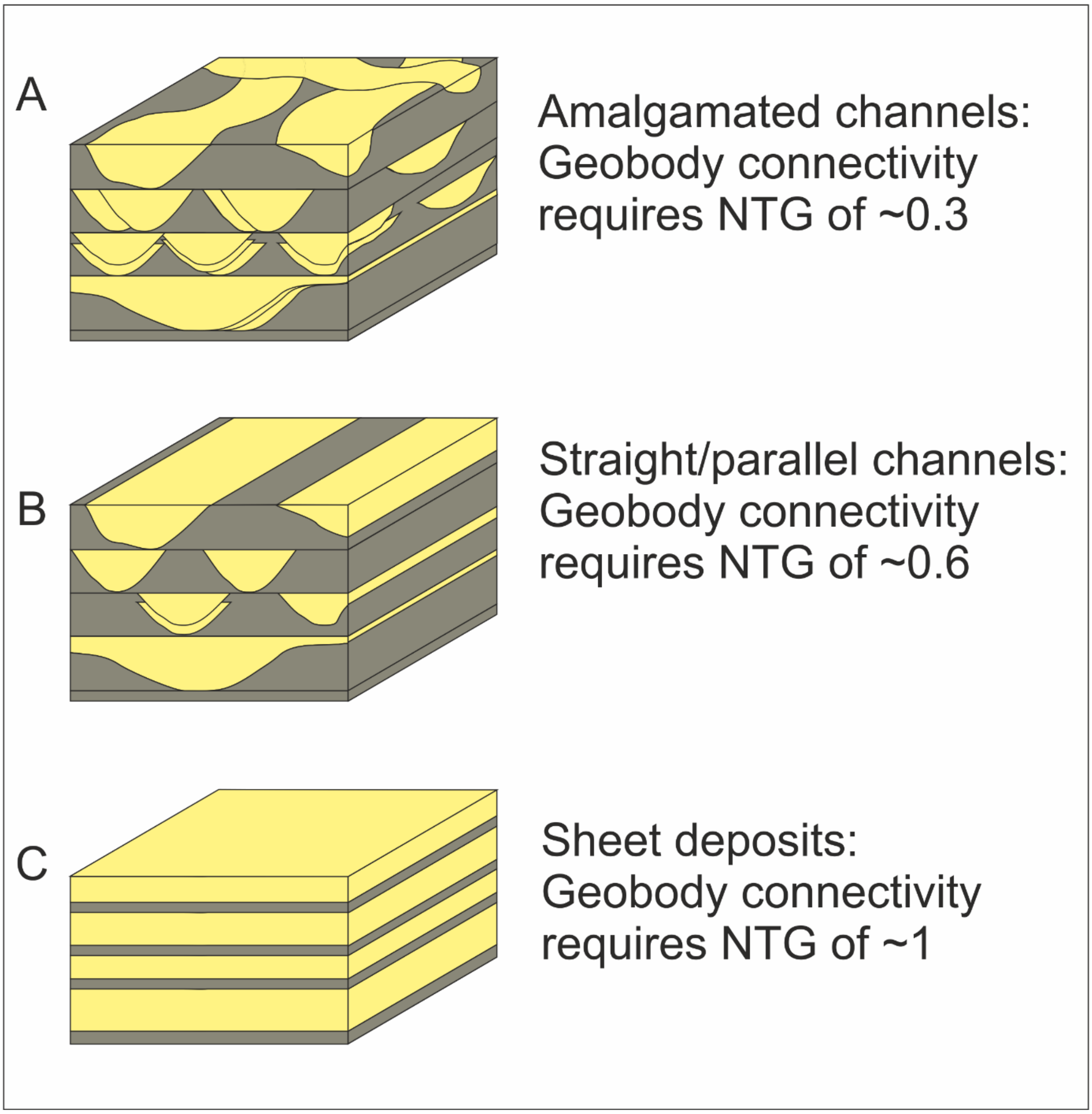

Figure 3. Net-to-gross (NTG) versus connectivity in reservoirs of different architecture (after Hovadik & Larue 2010, fig. 5). A, Stacked, amalgamated channel systems have good reservoir connectivity even with low NTG values. B, Straight, parallel channel systems have good reservoir

connectivity only when NTG values are moderate–high. C, Sheet deposits typically have poor connectivity, even with high NTG values.

Turbidite successions are the main type of deep marine reservoir, formed where high-energy currents carried large volumes of sand down the continental shelf into a marine basin. A number of such fields occur in the UK North Sea and stratigraphic compartmentalization within them is controlled by the geometry and connectivity of the sandstones. Since turbidite sands are typically transported in channels or down canyons, the lateral and vertical variability of these features is key to determining how compartmentalized a turbidite reservoir is.

In the Pierce field of the North Sea, Scott et al. (2010) argued that compartmentalization was controlled by stratigraphic architecture, with early Cenozoic turbidite sandstones being channelized around a pair of salt diapirs. The contemporaneous turbidite succession of the Nelson Field does not have salt diapirs present, but channelization of the sandstones still controls the compartmentalization, creating nine stratigraphic drainage cells (Gill et al. 2010).

There are many different types of marginal marine (paralic) successions and the dimensions of the reservoir intervals within them are accordingly variable (Fig. 4; after Reynolds 1999). The largest sand bodies by area occur in shoreline successions deposited during periods of high sea-level, and the thickest in lowstand valley sandstone succesions, whilst crevasse and crevasse channel sandstones are the narrowest and thinnest (Fig. 4; after Reynolds 1999, figs 5, 6).

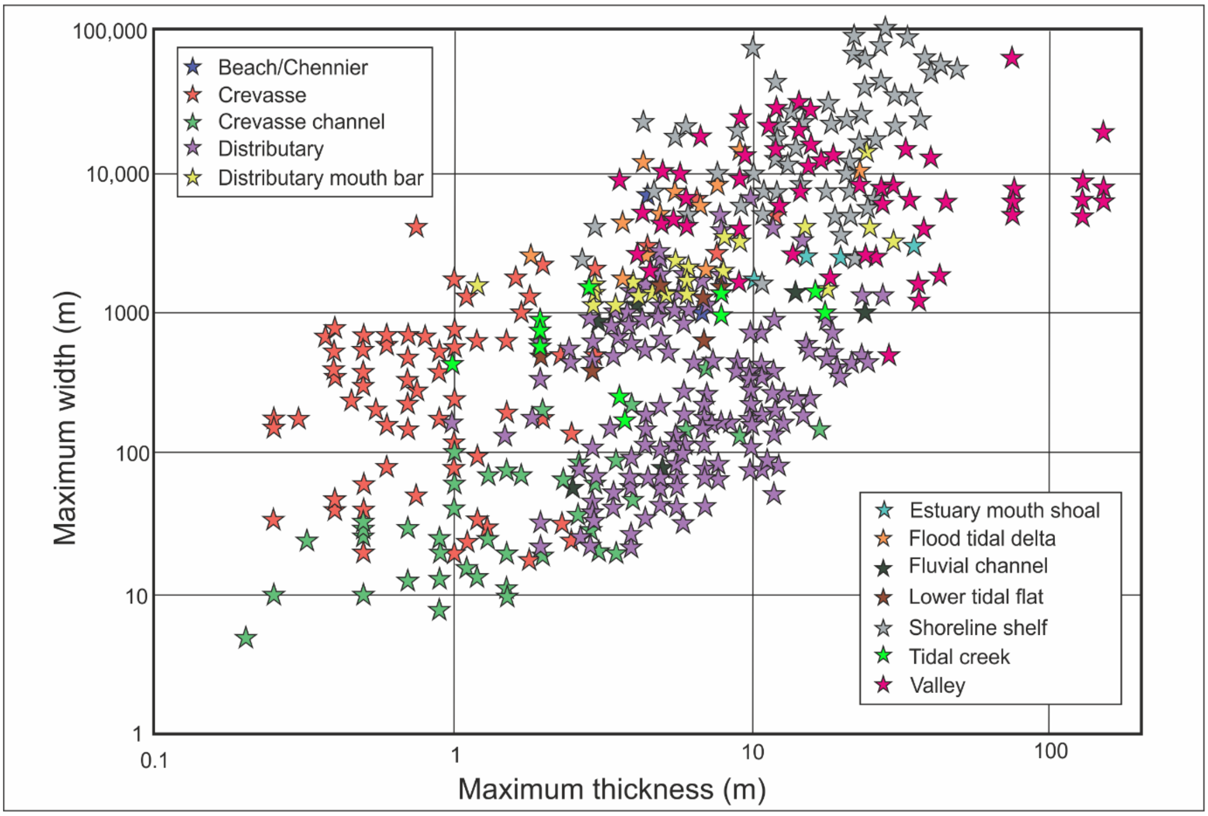

Figure 4. Sandbody dimensions of different reservoir types (after Reynolds 1999, figs 5, 6). Crevasse and crevasse channel successions are typically thinnest and narrowest, whilst shoreline shelf and valley successions are thickest and widest.

In general, though, NTG ratios in shallow marine reservoirs tend to be higher than deep marine successions due to their elevated sand content. Stratigraphic compartmentalization of marginal marine successions then occurs at three scales: intra-sandbody, inter-sandbody, and inter-parasequence scale (Ainsworth 2010). All are the result of mudstones acting as baffles or barriers. Intra- and inter-sandbody scale compartmentalization occurs in heterogeneous sequences deposited during periods of high sedimentation rate. In contrast, inter-parasequence scale compartmentalization is created by flooding surface shales, produced during major marine transgressions. These mudstones will have a much greater extent and create much more laterally persistent barriers to reservoir communication. In general, though, with a high sand component, reservoirs deposited in wave-dominated shallow marine systems show low levels of stratigraphic compartmentalization (Ainsworth 2006).

Channelization of sandstones also creates stratigraphic compartmentalization in marginal marine successions. In the Northwest Hutton field, the reservoir intervals comprise Middle Jurassic sheet or channel sandstones deposited in coastal plain, marginal marine or shallow marine environments. Flint et al. (1998) showed that connectivity was generally good, but that stratigraphic compartmentalization was present and controlled by two main factors. The first was the laterally persistent mudstones of the lower Ness Formation, produced during a marine transgression and creating a widespread, low permeability barrier to vertical fluid flow. The second was the variable dimensions of channel sandstones, particularly in the fluvially dominated Etive and upper Ness formations, with fine-grained inter-channel sediments acting as barriers to horizontal fluid flow.

This type of horizontal stratigraphic compartmentalization is commonly also observed in reservoirs deposited in fluvial or aeolian environments. Major barriers to vertical fluid flow are most prevalent in terminal fluvial systems, where the greatest quantities of mudstone accumulate. This was described in the Triassic Heron Cluster of the North Sea by McKie et al (2010), who noted that thin shale intervals could be breached by subsequent channel sands, providing connectivity. Thicker shales deposited in terminal, flood basin regions, however, were rarely incised by sandstones and therefore created barriers over tens of kilometres. A similar scenario has been predicted by Archer et al. (2010) for the Jasmine Field, with the laterally extensive Julius and Jonathan mudstone intervals being likely to create stratigraphic compartmentalization within the Joanne Sandstone over production timescales.

For terrestrial successions deposited in semi-arid, alluvial and braided fluvial environments, the reservoir intervals occur within channel and sheet sandstones, the shifting nature of braided channel systems providing good lateral and vertical connectivity of sandbodies. Stratigraphic compartmentalization is caused primarily by overbank (floodplain) mudstones, and playa lake mudstone and evaporite (salt) deposits, particularly in distal settings. This is discussed further below in the context of the stratigraphy and compartmentalization of the Bunter Sandstone Formation.

Recognition of stratigraphic compartmentalization:

One of the key approaches for identifying stratigraphic compartmentalization early is the use of sequence stratigraphy. Understanding relative changes in sea-level during the deposition of a reservoir succession enables a field-scale stratigraphic framework to be produced. As they have the greatest lateral extent, parasequence-bounding shales (mudstones deposited during periods of high sea-level) are stratigraphic compartmentalizers of the highest importance. Similarly, sequence boundaries (erosive surfaces produced during sea-level fall) can produce widespread changes in permeability that compartmentalize a reservoir.

In the Upper Jurassic turbidites of the Buzzard Field, North Sea, stratigraphic compartmentalization was identified shortly after production began by pressure-time analyses of pressure monitoring wells adjacent to a production well (Ray et al. 2010). These data showed that, after water injection began, pressure declined in three wells but increased in a fourth. Re-examination of seismic and stratigraphic data revealed that a previously unrecognized mudstone interval was partitioning this region of the field into vertical compartments.

The turbidite reservoirs of the Schiehallion Field, meanwhile, were initially thought to be well-connected. However, once production began, it transpired that they were more stratigraphically compartmentalized than predicted, due to a greater number of localized mudstones acting as barriers to flow (Gainski et al. 2010). As a consequence, more than double the number of production wells had to be drilled; 4D seismic and downhole pressure data have been used subsequently to monitor evolution of the field.

In block 21/28a of the UK central North Sea, six wells were drilled between 1971 and 1989, encountering oil and gas in a series of Eocene sandstone reservoirs. The discoveries were named Fyne and Dandy (Gluyas and Swarbrick 2004). The fields never went into production, however, as RFT pressure analyses indicated that the reservoirs were not in communication, but for unclear reasons. In the late 1990s, higher resolution seismic surveys and palaeoenvironmental analyses were carried out (Gluyas and Swarbrick 2004), showing that there were four separate hydrocarbon pools in a complex submarine fan succession. Though the individual sandstone reservoirs were of good porosity and permeability, they comprised elements of a meandering channel system separated by numerous mudstones, and the complexity of this meant the fields did not go into production.

Stratigraphic compartmentalization and CCS in saline aquifers

Unidentified stratigraphic compartmentalization has the potential to significantly reduce the viability of a site for carbon storage. The Snøhvit project in northern Norway was predicted to be able to store 23 Mt of CO_2 in a saline aquifer within the Tubaen Formation, 2400 m below the sea floor (Hosa et al. 2011). However, unexpected compartmentalization encountered during the early phase of injection led to a rapid pressure increase and a greatly reduced storage volume (Eiken et al. 2011). One interval – comprising only around one-sixth of the reservoir interval – received most of the injected CO_2, with the compartmentalization being primarily stratigraphic. A previously unrecognized shale interval is thought to act as a barrier to vertical flow, with possible additional compartmentalization caused by channel sandstones (Eiken et al. 2011).

Brine-filled domes in the Bunter Sandstone Formation of the UK southern North Sea (Fig. 1) have been targeted as promising potential CO_2 storage sites. Due to the more limited lateral and temporal extent of the sandbodies, fluvio-aeolian reservoirs such as the Bunter are often more stratigraphically compartmentalized than shallow marine systems, though as Reynolds (1999) discussed, there is wide variability in paralic (marginal marine) successions. Fluvio-aeolian reservoirs are also prone to vertical changes in lithology (from permeable sandstone to impermeable shale or salt) and horizontal changes in the dimensions of lithological units (most notably the channelization of permeable sandstones). To determine the migration pathway of any injected CO_2, therefore, the distribution and continuity of low permeability layers in the Bunter Sandstone needs to be assessed (Williams et al. 2013).

Few direct data are available for the saline water-bearing stratigraphic traps, but a small number of Bunter domes in the North Sea – Caister B, Esmond, Forbes, Gordon and Hewett – are productive gas fields (Fig. 1). Potential carbon storage sites lie within this region, so published data on the geology of the gas fields provide a source of information on potential stratigraphic compartmentalization within the Bunter Sandstone Formation.

Bunter Sandstone gas fields

In the Hewett Gas Field (Southern North Sea), the Bunter Sandstone is around 600-800 feet (180-260 m) in thickness, and comprises thick, fluvial channel and sheetflood sandstones with an average NTG of 0.96 (Cooke-Yarborough 1991, Cooke-Yarborough & Smith 2003). A second sandstone reservoir interval is also present: the Lower Bunter (Hewett) Sandstone, a fault-controlled, laterally restricted sandbody of late Permian–early Triassic age. This occurs only in the Hewett Field and a small adjacent region of the Dutch North Sea (Geluk 1999). It has an average NTG of 0.86, and is up to 200 feet (61 m) thick in the main Hewett Field, but thins rapidly northwards to a thickness of only 20 feet (6 m) (Cooke-Yarborough 1991; see also Clarke 2014). The two sandstone reservoir intervals are separated by anhydritic floodplain mudstones of the Bunter Shale, which are up to ~800 feet in thickness. The Bunter Shale and the younger, dolomitic Dowsing Formation act as both lateral and vertical seals across the field.

The stratigraphy of the Bunter Sandstone in the Hewett Field was not discussed by Cooke-Yarborough (1991) or Cooke-Yarborough & Smith (2003), but further data can be obtained from its stratigraphy in nearby gas fields. In the Esmond Complex (the Esmond, Forbes and Gordon fields), the formation is 400-500 feet (120-150 m) thick (Ketter 1991). The sandstones are predominantly sheet-like, but with three internal hierarchies of heterogeneity: cross-sets, channels, and channel complexes. Five lithofacies were described, with the highest porosity-permeability values occurring in sheetflood sandstones and tabular-planar upper channel fill sandstones.

Reservoir analysis by Ketter (1991) also identified seven discrete zones within the formation: an upper sandstone (Zone I), a deep red silty mudstone acting as a seal to the units below (Zone II), a thick, uniform sandstone (Zone III), an interval of mixed sandstone and mudstone (Zone IV), two intervals of fluvial channels and sheetflood sandstones (Zones V and VI), and a lower interval of increasingly silty sandstone (Zone VII). Zone III is the primary reservoir interval. More recent work on the Esmond Complex (Centrica 2005) has shown that there was low to very low aquifer support in most reservoir intervals, but that active aquifer support was present in Zone III of the Forbes field.

In the Caister B gas field, where the Bunter is around 150m thick, Ritchie and Pratsides (1993) described a sheetflood sandstone-dominated succession, which they divided into five stratigraphic intervals of varying NTG values. Using wireline log data, Williams et al. (2013) also identified five stratigraphic zones within a Bunter Sandstone dome in block 44/26 of the southern North Sea (Fig. 1). These comprise a thin, shale-dominated Zone 1, a thin Zone 2 of shales and cemented sandstones, a thick Zone 3 of sandstones with thin shales, a thick sandstone-dominated Zone 4 with discontinuous shale layers, capped by a 1–2 metre-thick cemented sandstone, and a thin Zone 5 of sandstones and shales. The non-cemented sandstones have 5–35 % porosity, but very limited permeability data were available.

During the deposition of the Bunter Sandstone Formation, sediment transport was in a broadly north-easterly direction (Warrington & Ivimey-Cook 1992), so the axial orientation of higher permeability channel sandstones is likely to follow that trend. There are also differing degrees of cementation within the formation. The cemented sandstone at the top of Zone 4 is widespread, extending into Caister B (Williams et al. 2013), but its lateral continuity is unresolved.

In the Esmond Complex, Ketter (1991) described the communication between reservoir intervals as ‘good though locally tortuous’, with fluid flow paths being better along the axes of the fluvial channels (broadly N-S) than across them (broadly E-W). Cooke-Yarborough & Smith (2003) described “remarkable” communication between the different reservoir intervals in the Hewett Field, even across faults. This has been developed further by Clarke (2014), whose fault connectivity analysis indicates that reservoir communication between the Hewett and Little Dotty fields – across the North Hewett fault of the Dowsing Fault system – is driven by the juxtaposition of reservoir sandstones in the southern region of the fault.

Despite the heterogeneities, the very high NTG values recorded for the Bunter Sandstone in the Hewett, Esmond Complex and Caister B fields indicate that connectivity should be very good (cf. Hovadik & Larue 2010), and there is no indication of compartmentalization in the Bunter gas fields (Holloway et al. 2005). Furthermore, variations in reservoir architecture within channelized sandstone successions may not matter if those variations do not affect reservoir connectivity or tortuosity (Larue and Hovadik 2006). Williams et al. (2013) stated that most of the low permeability shales and cemented sandstones in the Bunter are not laterally continuous, and would therefore have little effect on CO_2 storage potential. This is supported by Clarke (2014), who showed that a widespread shale interval predicted to act as a barrier to vertical fluid flow in the Upper Bunter of the Hewett Field did not actually act as such.

Gas production from the Bunter Sandstone Formation of the Hewett Field was thought to be by depletion drive, but recent work by Clarke (2014) shows that, whilst this is true of the Lower Bunter reservoir interval, the Upper Bunter reservoir experienced aquifer drive. In the Esmond Complex, meanwhile, aquifer influx coefficients indicate that the depletion-driven Esmond and Gordon fields will not have undergone significant repressurization since they were abandoned (Centrica 2005). In the Forbes field, however, aquifer drive in the main reservoir interval (Zone III) means that repressurization since abandonment is likely. This potential drive mechanism variability within Bunter reservoirs needs to be taken into account when planning CO_2 injection strategies.

Further information could be obtained from analysis of fluid properties. In the Hewett Field, the trapping structure formed between 50 and 150 Ma (Cooke-Yarborough 1991), an age range that is likely to apply to other Bunter Sandstone reservoirs. Based on the work of Smalley & Muggeridge (2010), all fluid properties ought to have equilibrated over that time scale, even by molecular diffusion, so if analysis of fluid composition was carried out, any variations in fluid composition would suggest the presence of reservoir compartments.

Summary and conclusions

The impacts of reservoir compartmentalization on the geological storage of carbon dioxide have been little-considered previously, particularly in terms of stratigraphic variation. This review shows that techniques used to detect compartmentalization in oil and gas fields are of relevance to understanding the prospectivity of saline aquifers as sites for the geological storage of carbon dioxide.

As a particularly prospective CCS reservoir interval, the Bunter Sandstone Formation must be carefully assessed for compartmentalization before the injection of CO_2 commences. The case studies of Bunter gas fields from the UK North Sea described above show that stratigraphic heterogeneities are present in the formation at various scales. Typically, five to seven main stratigraphic units have been recognized within the formation, though in the Hewett Field, a distinct, lower reservoir unit also occurs. There is potential therefore for lateral and vertical variation in the reservoir properties of the formation across the UK Southern North Sea. Nonetheless, the high NTG values documented, and the limited lateral extent of stratigraphic barriers mean that vertical and horizontal connectivity within the formation is likely to be good, and the risk of significant compartmentalization low. Exploration data on the geochemistry of produced fluids would help clarify this.

Numerous case studies from oil and gas fields show that, nonetheless, the precise nature of the compartmentalization of a reservoir is often determinable only after production has begun. For saline aquifers thought to be prospective for the storage of carbon dioxide, the collection of detailed stratigraphic information, seismic analysis, and assessment of fluid properties within the formation will provide a general indication of the presence of reservoir compartmentalization. Experimental drilling and injection, however, is likely to be the key means of clarifying the distribution, orientation and connectivity of any compartments – and therefore the true storage potential – of such units.

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