

STORAGE RETENTION TIME OF CO₂ IN SEDIMENTARY BASINS; EXAMPLES FROM PETROLEUM SYSTEMS

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ABSTRACT

Questions often asked by the public in regard to the concept of CO₂ storage include; “But won’t it leak?”, and “How long will it stay down there?”. The natural environment of petroleum systems documents many of the processes which will influence CO₂ storage outcomes, and the likely long (geological) timeframes that will operate. Thousand of billions of barrels of hydrocarbons have been trapped and stored in geological formations in sedimentary basins for 10s to 100s of millions of years, as has substantial volumes of CO₂ that has been generated through natural processes. Examples from Australia and major hydrocarbon provinces of the world are documented, including those basins with major accumulations that are currently trapped in their primary reservoir, those that have accumulated hydrocarbons in the primary reservoir and then through tectonic activity spilled them to other secondary traps or released the hydrocarbons to the atmosphere, and those that generated hydrocarbons but for which no effective traps were in place for hydrocarbons to accumulate. Some theoretical modelling of the likelihood of meeting stabilisation targets using geological storage are based on leakage rates which are implausibly high when compared to observations from viable storage locations in the natural environment, and do not necessarily account for the likelihood of delay times for leakage to the atmosphere or the timeframe in which geological events will occur. Without appropriate caveats, they potentially place at risk the public perception of how efficient and effective appropriately selected geological reservoirs could be for storage of CO₂. If the same rigorous methods, technology and skills that are used to explore for, find and produce hydrocarbon accumulations are now used for finding safe and secure storage sites for CO₂, the traps so identified can be expected to contain the CO₂ after injection for similar periods of time as that in which hydrocarbons and CO₂ have been stored in the natural environment.

INTRODUCTION

A significant public perception issue for CO₂ storage in sedimentary basins is how long any injected CO₂ will remain stored in the reservoirs in the geological traps [1]. This is in many ways a different issue to leakage rates, but they are obviously implicitly related. The contrast that separates these two issues is that if there is any likelihood of substantial leakage that can be observed within human timeframes (100’s of years) then it may not be considered effective as a storage site. It can also be argued that many observations of natural leakage rates come from known “leaky systems” and thus may not be representative of actual leakage rates that would be expected from appropriately selected secure storage sites equivalent to those naturally trapping hydrocarbons and CO₂. Amongst practising petroleum geoscientists it is well understood that the time frame for hydrocarbons and other gases and fluids to remain trapped in the subsurface is of the order of millions of years and much, much longer. However, some non-geoscientists might be unaware of the magnitude of this storage time, or when not working in the geosciences discipline might be unfamiliar with contemplating such long time frames. An example of such occurrences can be found in recent literature on accounting and mathematical modelling of CO₂ storage where conceptual rates of leakage and retention time have been relied upon in the modelling. These rates and timing have been extrapolated to the total volume of CO₂ stored at some stage in the future, to produce a total volume of leakage into the atmosphere. What is not clear in some literature is whether these rates are intended to represent reality, or are just a theoretical exercise of what the maximum rate should be to allow stabilisation at a certain target. Whilst such an approach is valid if presented in the correct manner, the results can only be considered appropriate if the storage times and leakage rates are geologically accurate, not just conceptual, and only if they discuss what type of leakage they are modelling, be it either natural processes or man made (e.g. old well bores). Pacala [2] estimated how a range of leakage rates and retention times would impact on the net mitigation at the global level, and analysed

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this in terms of the three stabilization targets of 750, 550 and 450 ppm. Pacala [2] discussed leakage rates of up to 0.5 to 1% / annum and total storage times ranging from 42 to ~ 1000 years in total. It is difficult to justify such assumptions in geological terms, as evidenced from natural accumulations of hydrocarbons and CO₂ described below, where storage times of millions of years are normally present in viable petroleum systems. Similarly Hepple and Benson [3] describe the need to establish “what would be an acceptable surface seepage rate” so as to ensure that particular stabilisation targets are met and that allowable emissions are not exceeded. Neither of these papers [2, 3] attempted to address in any comprehensive way what leakage rates and storage times are likely to be based on evidence from viable storage sites in the natural environment, and the likely operating regimes for injection sites, nor how long and at what stage it might be before any appropriately selected injection site could be at risk of leakage to the atmosphere. The circumstances whereby such important facts are not discussed in conjunction with the theoretical modelling, introduces a risk that the general public will read such theoretical reports literally and treat such leakage rates as scientific fact, beginning on day 1 of an injection operation. Some non-geoscientists are likely to have little experience in dealing with geological timeframes and geological processes, and there is a significant likelihood the CO₂ scientific community may do themselves a disservice unless such results are appropriately worded with suitable caveats using simplified but carefully worded explanations. Dooley and Wise [4] do give appropriate caveats and pose the question back to geoscientists of what is likely to be a technically sound assessment of storage times and leakage rates. An additional factor that needs to be added into the theoretical modelling is what delay time is likely to occur before leakage to the atmosphere begins, not just assume a leak rate at day 1. Such delay times may be very long (1000s of years), even in very poorly sited injection locations, or even in what otherwise would be described as a “leaky trap”. It is anticipated that such delay times will significantly alter the modelling. As a result, one of the purposes of this paper is to inform non-geoscientific researchers who are not used to working in the geosciences field, of the manner in which hydrocarbons and CO₂ are generated and trapped in the subsurface, and the timeframes and processes by which this occurs. The processes by which accumulations can form, be destroyed or escape are vital issues for the non-geoscience community to comprehend and accept. Such a knowledge base underpins the entire concept of CO₂ storage, and is presented in summary form in this paper so that the analogy can be more easily appreciated.

FORMATION AND TRAPPING OF HYDROCARBONS

Formation and storage of fluids and gases in geological formations will vary widely depending on where and how they are trapped. To describe the vagaries of how this occurs, it is useful to review the concept of petroleum systems, event charts and the geological processes by which hydrocarbons are accumulated in the subsurface, for which there are many analogues for geological storage of CO₂. Specific examples from Australia and the rest of the world will be used in the discussions. Hydrocarbon accumulations are formed in the subsurface where there is a synergy between source rocks, charge, migration, trapping and preservation (time). These aspects form what is known as a “petroleum system” [5]. Initially organic matter rich source rocks need to reach a level of thermal maturity such that the resulting amount of thermally generated hydrocarbons exceed the storage capacity of the fine grained sediments and are expelled (i.e. primary migration) into coarser grained rocks. The temperature driving this process emanates from heat in the crust, and its extent is principally related to the depth at which geological formations have been buried. Sedimentary basins are continually buried through the process of infill with sediments and resulting subsidence, which occurs gradually over millions of years, and is also affected by global scale tectonism causing episodic movement. Often the basins will reach in excess of 10 km thickness of sediments and have a temperature gradient of around 25°C / km of burial (10°C – 60°C / km range; [6]). The temperature at which hydrocarbon generation begins (>100°C) is well understood, but depending on the nature of the organic matter that is being thermally altered, it will vary in terms of the actual temperature and depth range at which it occurs [7]. Commonly the main phases of generation will commence below 3 km of burial and temperatures exceeding 100°C. Importantly, oil will normally generate before gas, and eventually the source rock will become extremely “over-mature” (>200°C) and cease to generate any further hydrocarbons. When hydrocarbons cease to generate in a basin is a critical moment to help estimate storage time. Carbon dioxide can also be generated from the maturing organic matter within the oil and gas generation range. However, this input generally accounts for < 5–10 mole% of the natural gas. For natural gases with higher CO₂ contents (up to > 99 mole%) there is an inorganic origin for the CO₂ [8], often forming at greater depths in the crust, such as from volcanic sources which can migrate up into shallower reservoir rocks using faults as a conduit.

Any hydrocarbons that are expelled will migrate through the pores of coarser grained carrier beds (secondary migration – e.g. sandstone and limestone) due to capillary forces and buoyancy until they are trapped in a structural

feature (e.g. anticline or fault block) beneath or adjacent to a permeability barrier, such as shale, that acts as a seal. If the geological trap into which the hydrocarbons migrate has formed and is in place before the time of hydrocarbon generation, known as the “charge”, then hydrocarbons will accumulate within the reservoir rocks. If large volumes of hydrocarbons are generated and the trap capacity is exceeded, then the excess hydrocarbons will “spill” out of the trap as it over fills and move further along the carrier beds (usually porous sandstone) until they encounter another trap. Often hydrocarbons will be generated but are not trapped as the pathway of their migration does not intersect structural traps. This process from source to trap is mostly not very efficient due to the pure chance of nature for it to occur. Often a large proportion of the migrating hydrocarbons remain along the migration pathway within the pores of the carrier beds, with the result that perhaps not all available traps are filled or even that the initial trap is not filled to spill. The analogue for CO₂ storage is that with long migration pathways following the injection process, then CO₂ will also be distributed and trapped along the migration pathways, both within pores of the rock and (specifically for CO₂) as it dissolves into formation fluids (water), and not just be located in structural culminations. If there is no barrier to hydrocarbons being physically trapped, then they will migrate through the geological formations until they reach the surface (usually at the edge of the sedimentary basin), and they then will be released to the atmosphere or sea-floor. Many major petroleum fields have been found through the process of searching for hydrocarbon “seeps”, which have spilled from large accumulations, or simply have provided the clues that the basin is a productive hydrocarbon province which through a rare natural ordering of events might have enabled hydrocarbons to migrate into structural traps within the sedimentary basin. The proportion of hydrocarbons generated in sedimentary basins versus those which by chance were trapped and accumulated in structural features (generation-accumulation efficiency) often will be well below 10%, but in some rare petroleum systems will approach 40% [9]. The process of natural storage of CO₂ versus injection has differences of timing, volumes and rates which will influence determinations of what is a viable storage site. A substantial advantage for the efficiency of the injection and storage process is the ability to not rely on natural random chance for suitable storage sites, but to explore for, test and monitor a site either before injection, or in the early stages of the project. Geomechanical effects on the reservoir and seal can potentially occur during injection, but these can be predicted and monitored, and engineering solutions can be designed to account for such effects [10].

EVENT CHARTS

All the major petroleum provinces of the world have undergone detailed analysis of each of the key petroleum system processes [5, 11], with the most critical aspect being the relative timing of each process. It is common to construct for each basin or petroleum system, a series of charts including a burial history chart and an event chart [12, Fig 1.2 and 1.5]. Burial history charts are used to help construct event charts and they show the history of the basins development, including how thick the sediments are that filled the basin, and when particular sediments became deep enough and reached thermal maturity to expel hydrocarbons. Event charts summarise the fundamental knowledge base that is used in sedimentary basin analysis. Figure 1 shows an example of an event chart for the Gippsland Basin in Australia, and includes a number of processes and events. The event chart plots geological process and events against a geological timescale, identifying both the relative time and respective order of their occurrence. In this way it is easy to recognise for any given petroleum system, when in geological time hydrocarbons were generated from source rocks, when the source rocks first expelled hydrocarbons and finally became over mature and ceased generation, when traps formed, and by deduction how long hydrocarbons have remained trapped in each petroleum system. When these event charts are examined across the world, they show that it is quite common for hydrocarbons and naturally formed CO₂ to have been trapped and stored in sedimentary basins for many millions of years and in some rare cases hydrocarbons have been stored for over a billion years..

STORAGE TIMES

For the continent of Australia, most significant sedimentary basins have event charts, including all minor and major petroleum provinces [13, 14 & 15]. Australia has over 300 sedimentary basins, which include 9 producing basins and perhaps 20 that have significant hydrocarbon potential. There are 3 geological provinces that could be categorised as being world class sedimentary basins for hydrocarbon accumulations. These basins represent a large range in ages from the Proterozoic (>545million years) to the Cainozoic (0 – 65 million years), and include clastic (e.g. sandstone and shale) and carbonate (e.g. limestone) sequences. The basin classifications include rift, passive continental margins and intercontinental basins. Some have been affected by extensional as well as compressional tectonics, and many have been affected in their evolution by major tectonic collisions of continental plates. Due to their geological diversity, they are ideal analogues for comparisons with basins from the rest of the world.

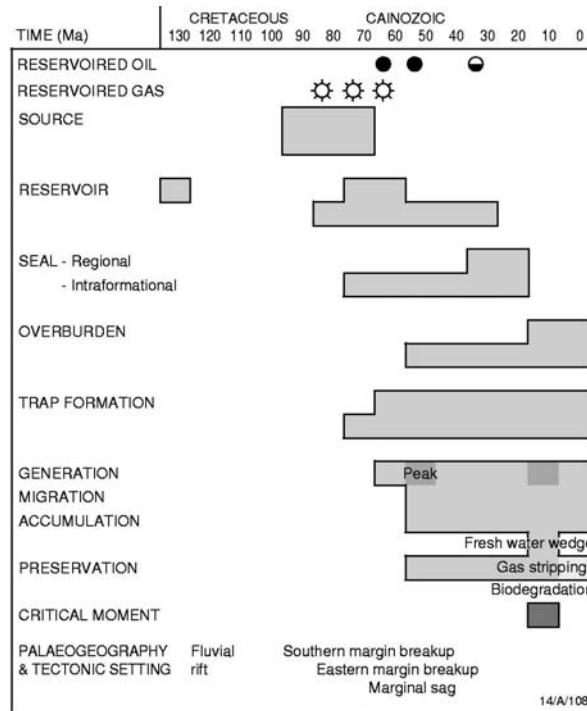


Figure 1: An example of a petroleum systems Event Chart for Australia from the Gippsland Basin, showing processes and events that have influenced the timing of formation of hydrocarbons. Each event or process has a start and end point in geological time and a duration, as well as the age of the geological strata that oil and gas accumulations are stored, and geological age of reservoirs and seals.

Table 1 shows some sedimentary basins within Australia with their hydrocarbon potential and their respective timings for storage, whether they contain significant hydrocarbon accumulations or just have indicators of hydrocarbons (show), as well as any volumes of CO₂ that they have naturally accumulated and stored. In Australia, the world class petroleum provinces have storage times of 10 to 80 million years (Table 2), other significant accumulations have been preserved for 65 - 300 million years, whilst the McArthur Basin has a minor accumulation / oil show that has remained stored in its reservoir rocks after over a billion years. The Carpentaria Basin is an example of where source rocks have not yet generated oil (immature source). The Arafura Basin (Goulburn Graben) has a negative mis-match in its timing as it generated oil 100 million years prior to trap formation, and so allowed the hydrocarbon fluids to escape to the surface. Some basins have significant hydrocarbon accumulations, but other factors, such as the poor quality of their reservoirs, make exploration for accumulations that can be commercially produced a difficult challenge (e.g. Amadeus, Cooper/Eromanga, Offshore Canning basins). Such challenges will face exploration for CO₂ storage sites, but the advantage is that CO₂ storage operators will control the timeline, the “charge” or injection, and selection of the precise injection site and migration pathway. By contrast, successful accumulation of hydrocarbons in an active petroleum system, have relied upon just the vagaries of nature. During exploration for oil and gas, 500 Mt of naturally generated and stored CO₂ has been unintentionally discovered in Australian sedimentary basins, which has been stored for up to 80 million years [16]. At a global level, Australia is a relatively minor player in terms of volumes of hydrocarbons generated and trapped. This is due principally to the quality of source rocks encountered, the age of many of its sequences, and all the time that has transpired since trapping and the subsequent geological events that have occurred that have impacted upon prior accumulations (preservation). Table 2 shows a number of basins from the major petroleum provinces of the world. These include examples from the regions of the Middle East, Western Europe, North America, South America, and Africa. Collectively the specific examples from these regions account for nearly four hundred billion barrels of oil equivalent hydrocarbon reserves, which have a range in age of storage times from recent to 96 million years. Many of the provinces have stored most of their hydrocarbons for much longer times than indicated, but the approach taken was conservative in that only the youngest likely storage time for each province was documented, rather than the maximum likely times. Not listed in the table is an accumulation from Indonesia (Natuna Field) that contains ~

6800 billion m³ of gas (240 x 10¹² ft³), 70% of which is CO₂ (equivalent to ~9000 Mt of CO₂). The event charts from this field show that the gas charge is very recent with a minimum storage time of 0 -5 million years. Even if leakage rates of > 0.00001% / annum were commonplace in such geological provinces (which they can not have been), as opposed to the conceptual rates of 0.001 to 1% / annum used in some theoretical modelling [2, 3, 4], then the world would have no hydrocarbon accumulations, as they would have all leaked to the atmosphere many millennia ago.

TABLE 1: SELECTED BASINS FROM AUSTRALIA, THEIR RELATIVE TIMES OF STORAGE AND PETROLEUM PROSPECTIVITY, AND NATURALLY OCCURRING CO₂ VOLUMES. (SEE ALSO TABLE 2 FOR MAJOR PETROLEUM PROVINCES IN AUSTRALIA).

Basin Name	Indicative Storage Time Millions of years	Hydrocarbon Potential/ Indicator	Critical Elements & CO₂ Volume <i>(Note: If the process is a failure it is in italics and in brackets)</i>
Adavale Basin	65	Significant	Source/Timing – 0.03 Mt CO ₂
Amadeus Basin	300	Significant	Reservoir Quality
Arafura Basin (Goulburn Graben)	- 100	Show	<i>(charge predated trap formation)</i>
Bowen Surat	65	Significant	Regional extent of Seal - 1 Mt CO ₂
Carpentaria Basin	n.a.	n.a.	<i>(immature source)</i>
Cooper/Eromanga Basins	65	Significant	Reservoir Quality - 75 Mt CO ₂
McArthur Basin	1400	Show	<i>(Worlds oldest oil – preservation)</i>
Offshore Canning Basin	80	Show	<i>(source and reservoir)</i>
Perth Basin	65	Significant	Source Quality/Timing – 0.45 Mt CO ₂

TABLE 2: STORAGE TIME OF HYDROCARBONS IN THEIR MAJOR PETROLEUM PROVINCES OF THE WORLD, AND THE VOLUME OF OIL AND GAS (IN BARRELS OF OIL EQUIVALENCE) THAT OCCURS IN-PLACE TOGETHER WITH THE NATURALLY OCCURRING CO₂ VOLUME (AUSTRALIA).

Location	Basin / Reference & CO₂ Volume	Volume (in Place) Billion barrels of oil equivalent	Storage time Millions of years
Alaska (USA)	Ellesmerian [34]	77	96
Venezuela	Maracaibo [35]	36	20
North Sea	Central Graben [36]	28.2	20
Nigeria	Niger Delta [37]	4.2	45
Arabia	Greater Ghawar Uplift [38]	195.8	25
Australia	Carnarvon [15] – 100 Mt CO ₂	15.76	80
	Browse-Bonaparte [15] – 180 Mt CO ₂	9.4	40
	Gippsland [15] – 20 Mt CO ₂	7.05	10

TIMING

The impact of timing, and the need to have processes occur in the correct relative order, is probably one of the most important reasons that petroleum systems fail to trap and accumulate hydrocarbons. For geological storage of CO₂ however, timing will not be a factor affecting a viable trapping process. Injection of CO₂ (equivalent to charge) and migration will occur into an existing identified and suitable trap and carrier bed prior to the injection operation proceeding. In essence, the random chance and timing of nature, which influences success in a petroleum system, will be eliminated by prior knowledge and data acquisition. CO₂ storage has an additional advantage compared to natural storage in petroleum systems.. Injection operations will know very early in their life whether any unforeseen technical uncertainties exist, well before significant volumes of CO₂ could be actually stored. At such an occurrence,

operations can be modified, or in a worst case example they can be abandoned. If serious enough, the CO₂ plume could be identified with seismic data and targeted with drilling, and the CO₂ re-produced and transported to a more appropriate site, perhaps even back flowing it along the existing pipeline infrastructure.

PRESERVATION AND LEAKAGE OF HYDROCARBONS

The fifth vital component in the petroleum system is preservation. The preservation time can be extremely long, and can represent the longest interval in the geological history of a basin. In the case of the McArthur Basin (Table 1 - 1400 million years) it has been extremely long. Within the petroleum system, the source to trap aspect is of relatively short geological time compared to preservation longevity. However, once hydrocarbons have been trapped then there are many other processes that can result in subsequent losses and in some cases complete destruction of the palaeo-hydrocarbon accumulation. Such processes will be on geological timescales, not human timescales. The biological system is a ubiquitous process affecting preservation of oil and gas in the deep Earth. Thus degradation of petroleum through biological activity in the reservoir (biodegradation) is common at shallow depths where temperatures are below 80-90 °C [17]. Within Australian petroleum systems, biodegradation typically occurs above 1500 m, where hydrocarbons, as well as CO₂, can be altered [8]. Methanogenic bacteria utilise CO₂ to produce biogenic methane which adds to the already in-place thermogenic methane and a drier gas results [8]. Above this temperature, reservoir sterilisation is thought to occur [18] and water washing is the preferred alteration process that reduces the volume of hydrocarbons, in some cases by as much as 90% [19]. Biodegradation selectively removes the lower molecular weight components of an oil leaving behind a more dense and viscous material. This can effectively lead to immobilisation of the residual oil and prevent subsequent re-migration (e.g. 'heavy' oil and tar sands). Typically, biodegradation is a very slow process taking many 10s of million years to complete, after which time up to 70% of the oil mass can be consumed [20]. Immobilisation of CO₂ can occur with the reaction with specific minerals in the reservoir rocks, which is very facile and can occur within the timeframe of a few 1000s of years [21]. Within the petroleum systems of Australia, there are key tectonic events that have "destroyed" petroleum systems, due to high heat flows (e.g. cracking of oil to gas at high temperatures {> 150 °C} within the source rock, carrier beds or reservoir), uplift, erosion and collision with neighbouring tectonic plates. Associated with these major events, in some instances representing 3 - 5 kilometres of uplift and erosion (Amadeus, Arafura and Perth basins – Table 1), has been periods where any hydrocarbon accumulations that existed have been lost to the atmosphere. These events however, are extreme global tectonic events, where major changes occurred in the direction of drift of continental plates. They are not minor features such as localised earthquakes or movement on faults, and occur over 10s of millions of years, not 1000s of years.

Leakage from the reservoir is another process that can deplete a hydrocarbon accumulation. For an oil accumulation, subsequent gas charge can result in the oil becoming completely dissolved in the gas or the more buoyant gas displacing the oil and causing spillage of the oil from the reservoir. Importantly, the displaced oil can re-migrate (tertiary migration) and potentially be trapped under another seal. On the North West Shelf of Australia, such leakage resulted in the loss of an oil column of over 100 m, which was an accumulation containing 100s of millions of barrels of oil [22]. The geological event that produced this leakage was associated with plate tectonic activity when Australia collided with Timor around 5 million years ago. Pre-existing faults that were orientated in a specific direction relative to the compressional direction of the collision, were reactivated, and lead to the loss of the entire field. Such losses can be slow and take over 10s of millions of years to occur [23]. When risks of "catastrophic failure" are discussed for CO₂ storage, these are the types of events that could lead to loss of an entire accumulation, but they will only occur on geological timescales. Some clues to these losses are expressed in the subsurface as seismic anomalies [24] and on the Earth's surface. Seepage can be identified as sea-floor carbonate mounds and associated benthic biological communities that depend on the leaking hydrocarbons as food sources [25], as well as, by remote sensing techniques that depend on the characteristics of oil slicks on surface waters [25, 26]. Additional positive evidence of leakage can be seen in parts of the Australian coastline, which regularly receive strandings of bitumen due to seepage of oil into the water column from offshore sedimentary basins [27, 28], as well as there are many examples of gas leakage into the water column [24]. Identification of these natural leakages of hydrocarbons are routinely used to aid in petroleum exploration, and in many cases can be used to document "leaky systems" rather than basins that are actively accumulating and storing hydrocarbons. In many instances, even these "leakages" are from reservoirs where the hydrocarbons were initially generated and trapped between 10 and 100 million years ago, and the hydrocarbons have migrated to the flanks of the sedimentary basin before leaking into the atmosphere.

TIMESCALE RELEVANCE

Using human timescales (100s of years) in mathematical and economic modelling for CO₂ storage when the timing really relates to much longer geological timescales (millions of years) is probably not valid, although the rationale for such questions that are being asked might be relevant. Many of the geological regions that have been examined here for storage times equate to the “world class” petroleum provinces described by Bradshaw and Dance [29]. Globally there are hundreds of sedimentary basins that don’t fit this category, but still will have highly suitable characteristics for storage of CO₂, and in some instances will have even better storage potential [29]. How efficient and suitable such sites are for CO₂ storage will require case specific studies to fully determine their geological criteria. Such analysis are routinely carried out by petroleum geoscientists when assessing drilling prospects. On a climate change timescale, over the last 740,000 years, 8 major glacial – interglacial cycles have occurred [30]. Perhaps the timescale of such long term natural fluctuations in global climate should also be borne in mind when deciding what will be valid or suitable times for storage of CO₂. An implication from this might be that storage sites might not need to equate to the “world’s best” storage time outcome, as these will be extremely long timeframes compared with long term climate fluctuations. It might be appropriate to consider and discuss the options to utilise sites that might be “fit for purpose”, provided no safety or environmental issues are compromised.

DISCUSSION AND CONCLUSIONS

It is anticipated that many of the risks and uncertainties associated with leakage from appropriately selected storage sites will become evident early in a project, long before significant volumes are stored. The most critical factor associated with leakage to the surface on human timescales will be from well bores rather than natural subsurface processes. Well bores can be monitored, maintained and remediation performed if required either before or during the injection operation, and as such this risk can be controlled. A remediation operation can readily be achieved within a 3 month period, which is insignificant in terms of leakage volumes when considered over the timeframe of either an injection period, or the total storage time. If injection sites are appropriately selected down dip from structural culminations or hydrodynamic/solution traps are utilised, as opposed to direct injection into depleted fields, then the likelihood of leakage failure from wells will be very much lower again, as the injection pressures will have dissipated before the CO₂ gets to a leakage point, significant amounts of CO₂ will be trapped in closures with no well penetrations, and CO₂ will have dissolved into the formation water [31, 32]. Observations of leakage rates from natural processes in the subsurface such as fault reactivation and earthquakes [33] are short lived in terms of high rates of leakage, before dropping back to lower levels. Examples are required where the naturally occurring volume of escaping gas or fluid (not from wells) can be related directly to effectively stored volumes of gas or fluid in the subsurface. Such examples, if they exist, would provide invaluable guidance to realistic leakage rates relative to storage volumes and times. The timing of when leakage due to natural subsurface processes could occur post the injection period must also be borne in mind. If injection sites are chosen down dip from either structural culminations with well penetrations, faults or basin edges, then the time to migrate to leakage points could often be on the order of 1000s of years [31]. Even if vertical migration results in the CO₂ permeating through imperfect seals, then there still will be tortuous pathways that the CO₂ will have to migrate through to reach the surface, and again this may be on the order of 1000s of years [32]. The above discussion suggests that leakage to the surface in human timeframes from appropriately selected storage sites will only occur in substantial volumes through old well bores that are not maintained and remediated, rather than through natural subsurface processes [32], and even then, there may be significant delay times before leakage to the atmosphere occurs. This suggests that future research effort should strongly focus on old well bores and how to make them safe and secure with non-corrosive components and materials, and the potential impact of subsurface leakage (out of the primary reservoir into a secondary shallower reservoir) and potential contamination effects that could occur to subsurface resources (e.g. groundwater).

Some attempts at mathematical modelling has used unrealistic conceptual timeframes for leakage and storage when considered in terms of the actual geological evidence from the natural environment. There are numerous processes and events that can lead to the destruction and loss of hydrocarbon accumulations, but they are extremely long term events from substantial geological impacts (e.g. continental plate collisions). The operation of petroleum systems processes in the subsurface are well understood in the oil and gas exploration industry where hydrocarbons and CO₂ are trapped through the chance of nature. If the same rigorous methods, technology and skills that are used to explore for, find and produce hydrocarbon accumulations are now used for finding safe and secure storage sites for CO₂, the traps so identified can be expected to contain the CO₂ after injection for similar periods of time. With

appropriate site selection, this storage time will be on the order of many millions of years, not tens, hundreds or thousands of years. Reduced storage times and high leakage rates are more likely to be associated with well bores, than natural subsurface processes in appropriately selected sites, but such occurrences can be planned for and remediated through proper maintenance.

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