

ANNEX A1

CO2 Storage Liabilities in the North Sea – An Assessment of Risks and Financial Consequences

Well Risks

Jonathan Bellarby
AGR Petroleum Services

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1. Summary

This section analyses the risks of CO₂ migration from the reservoir to the biosphere from both active and abandoned wells.

Abandoned wells pose a real risk to the integrity of the storage complex as they potentially provide a migration pathway through the reservoir cap rock. Many (indeed the vast majority) abandonments were not designed with CO₂ service in mind although a quality abandonment suitable for hydrocarbon service is generally also suitable for CO₂ service. Generally, the quality of abandoned wells can be assessed, since records are maintained. In some limited cases, an inadequate abandonment across the cap rock may preclude the use of a storage site. Such cases generally involve wells that were abandoned having not encountered hydrocarbons and have not used a cement plug across the potential CO₂ reservoir cap rock. In most scenarios, an internal cement plug is used across the cap rock. There is still a risk that these plugs will eventually degrade upon exposure to CO₂. The probability of this occurring may be relatively high but the migration rates will be low due to a tortuous flow path and even over 1000 years total leakage may only total 1% of the stored volume. Wells designed specifically for CO₂ service or those yet to be abandoned and in the vicinity of the storage can be abandoned in such a way as to ensure that the risks to storage integrity are minimal.

The risks for active CO₂ injection wells are similar to those for any hydrocarbon production well and assuming a similar level of engineering in material selection and analysis is applied, there is no reason for the risks to be greater. All threats to CO₂ injector integrity can be managed, monitored and, if necessary, remediated. The double barrier principle (an independent primary and secondary barrier) enshrined in modern well design largely prevents catastrophic releases of CO₂ (or hydrocarbons) even though at any given time there is a real risk of losing one of the barriers. A failed barrier can usually be detected (especially the primary barrier) and quickly repaired. The residual risk arises from coincident failure of both barriers and the probability of this has been assessed for various migration routes. Instantaneous rates may be high but durations will be short as remedial measures are possible.

2. Abandoned Wells

Prospective storage sites for CO₂ are plentiful but require similar reservoir characteristics to the geological storage of oil and gas (porosity, permeability, trapping mechanisms, seal). This means that the vast majority of potential storage sites will have abandoned wells in the vicinity. Although potential storage sites could possibly be identified without nearby abandoned wells, such reservoirs will likely be lacking in data with which to assess their suitability.

In regions such as Texas, over a million wells exist, some dating back over 100 years. The quality of many abandonments is poor, with records also being poor – even to the extent of reporting the well's location and depth. In the UKCS, exploration and production is more recent and standards are generally, but not universally, higher. However, exploration wells that did not encounter hydrocarbons may have been abandoned in such a way that eventual CO₂ migration into the vicinity of such a well could pose a risk of further migration up the well and ultimately, potentially to the biosphere. A further risk exists where wells abandoned in an acceptable manner for hydrocarbon service allow CO₂ migration when exposed to CO₂ service (corrosive fluids and pressures or temperatures different from their design envelope).

2.1. Description of Problem

Wells are abandoned (i.e. decommissioned) for a variety of reasons. As of 2012 in the North Sea, most abandonments have been performed on exploration and appraisal wells rather than development wells. It would be very rare to not be able to find a number of abandoned wells within a few kilometres of any prospective storage site. Indeed, because of taxation relief, it was historically common to drill more exploration and appraisal wells than would be optimum under current fiscal conditions. Drilled wells may create potential leak paths for reservoir fluids, since the caprock gets disturbed during the construction process of the well. The installed seal in and around the wellbore may not be as robust as the original caprock.

2.2. Migration Pathways

Two assessments are needed for any well in the vicinity of a CCS storage site – could CO₂ migrate to the abandoned well and could CO₂ then migrate up the inside of the abandoned well or up through the formation or cement surrounding the wellbore of the abandoned well?

Once the CO₂ reaches the abandoned well, there are a number of migration pathways it can take in order to migrate to surface. For migration to occur, significant barriers, baffles and secondary storage reservoirs must be evaded or breached. Barriers or baffles can be in a vertical or lateral direction. For example (Figure 1), a cement plug inside the casing may be breached vertically or the casing may be breached laterally followed by vertical migration through rock strata. Lateral migration may then allow the CO₂ to travel relatively unimpeded through a mud-filled casing to a further plug. As can be imagined, the total number of potential migration routes for a given well will be very large. In many instances such as diffusion limited leakage rates, the CO₂ would be partially or completely absorbed (e.g. within porous water filled rocks) on this migration journey.

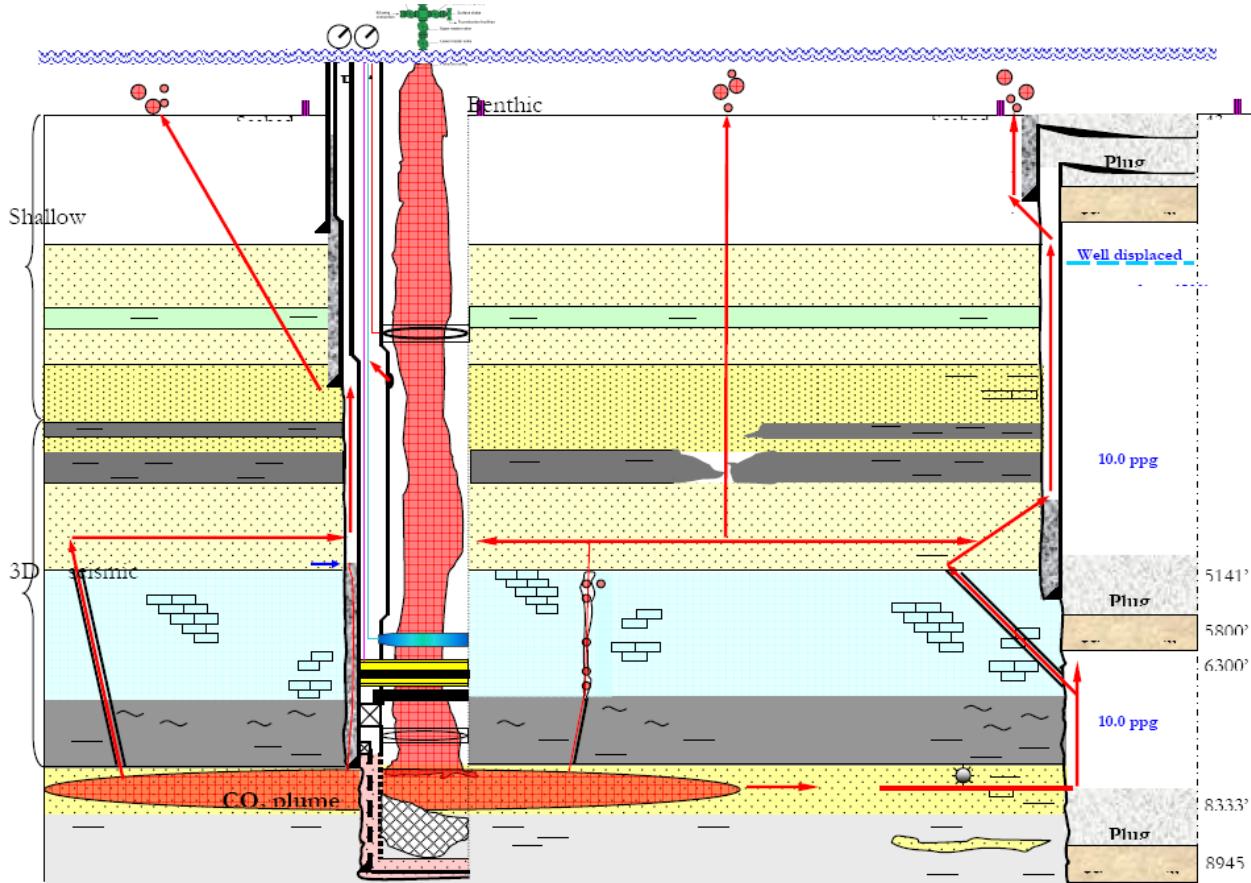


Figure 1 – Example of Potential Migration Pathways including Abandoned Wells

Under most CCS storage conditions (pressures and temperatures), CO₂ is buoyant (compared with the majority of the surrounding fluid, this being water). CO₂ will therefore tend to move up dip and accumulate below an impermeable layer. It will eventually dissolve in the water but this process is very slow (likely to be longer than a human lifetime). More important will be the structural and stratigraphic features of the reservoir and caprock and where CO₂ will migrate to. This has to be studied with an understanding of the specifics of the site.

As a minimum, the exact location of wells abandoned in the UKCS (UK Continental Shelf) will have been reported, and most commonly there will be an abandonment schematic showing the location and types of plugs, the casing and mud details and any testing of the plugs performed during the abandonment. Although location errors are common on many older wells and complete abandonment records may be missing from public records, detailed research with the operator (and even service companies) usually locates sufficient details including the end of well report and the daily drilling reports. These can provide further details. It is essential that all the wells that will or could potentially be in contact with CO₂ be analysed. P.D. Alesio (SPE 133056) describes a typical process for analysing abandoned wells. It is quite possible that the analysis uncovers wells that lead to unacceptable risks and therefore difficult (especially offshore) well re-entries would be required or, more likely, a switch to a safer injection target.

The critical seal in any abandoned well is across the caprock (Y. LeGuen et al, SPE 122510). In addition multiple other barriers will be present in the abandoned well. Because the wellhead and all casing strings close to the seabed will have been cut and recovered, access into an abandoned well is very complex and expensive. It is most unlikely that this would be attempted up front to remediate a perceived risk. Therefore all wells within reach of a

plume of CO₂ should be assessed for migration risk. In an ideal situation, the best barrier is a rock-to-rock cement plug with sufficient thickness – typically 10m - to absorb any CO₂ induced and diffusion controlled degradation. An example of such an abandonment is shown in Figure 2 with the well taken from the Goldeneye abandonment proposal (document UKCCS-KT-S7.16-Shell-002 Well Abandonment Concept), where Plug #1 provides a rock-to-rock seal. Note that the casing across the cap rock (Rodby Shale in this case) would have to be partially milled (under-reamed) as part of the abandonment process.

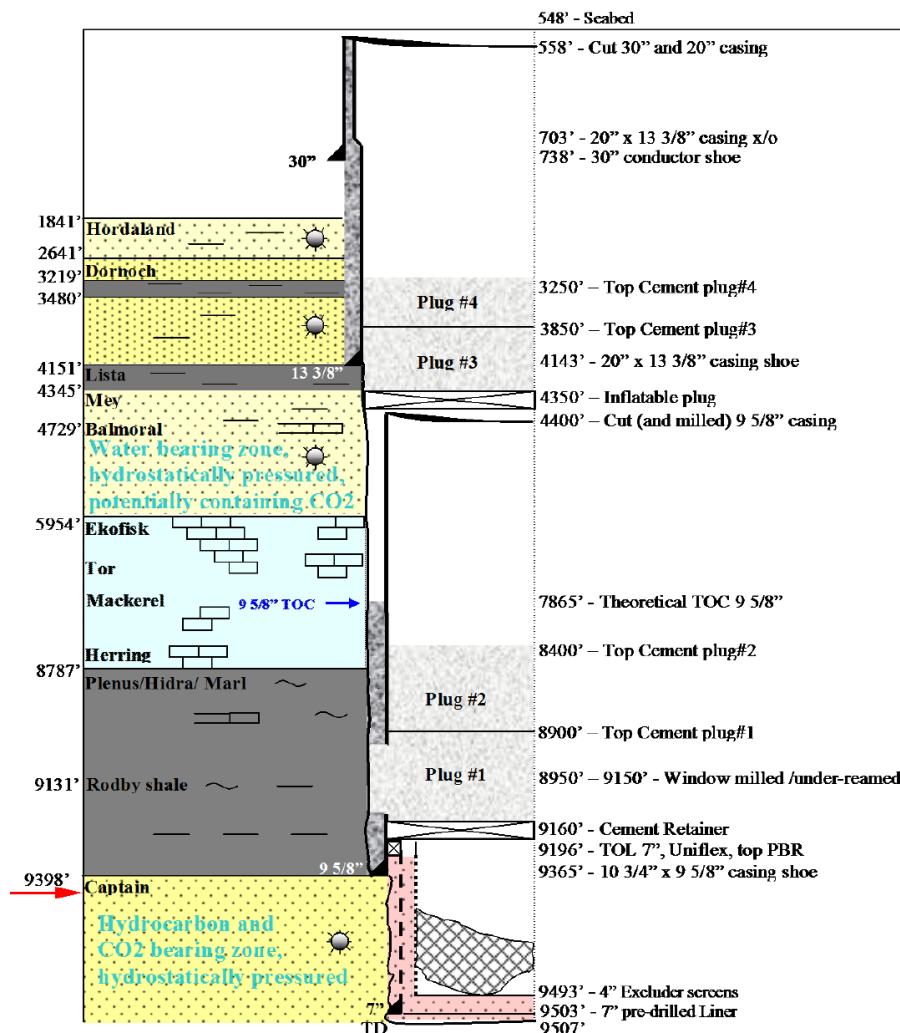


Figure 2 – Ideal Well Abandonment showing Caprock and Milled and Cemented Window (Shell Goldeneye)

Such an abandoned well is relatively rare (but becoming increasingly common (e.g. the abandonment of Shell's Brent wells when the original cement quality is assessed as poor) but if the rock-to-rock seal is present, it provides minimal opportunities for leakage as degradation of the cement by CO₂ is very slow (up to around 10 metres in 10,000 years in the case of Goldeneye) and is limited by diffusion transport of reaction by-products. CO₂ with cement reaction by-products have to be removed for fresh cement to be exposed to allow further degradation. Without flow past the cement, the removal of by-products is a (very slow) diffusion process, not aided by the soluble by-products being lighter than the solute.

A more common abandonment procedure is to place a cement plug inside a previously cemented casing. The internal cement plug (e.g. Plug #1 in Figure 3) would be pressure tested. This scenario provides nearly as much protection as although the casing can be easily corroded by CO₂ rich fluids (lateral casing corrosion rates are typically several mm/year under these conditions), the vertical degradation is again limited by diffusion. The main risk with this abandonment practice is the (often) unknown quality of the external cement, this being very difficult to pressure test.

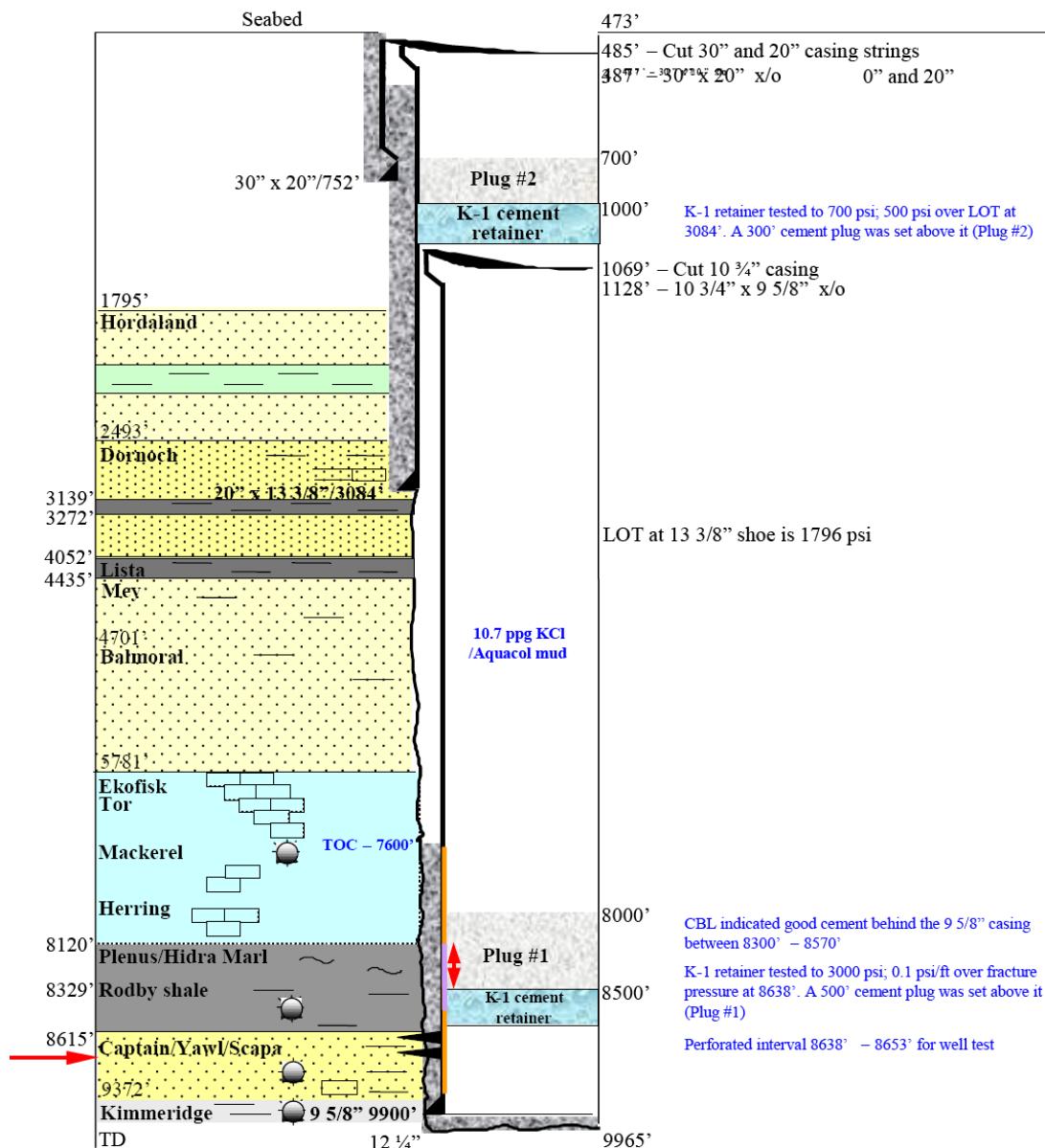


Figure 3 – Common Well Abandonment showing Caprock and Internal Cement Plug (Shell Goldeneye)

Where there is no internal cement adjacent to the cap rock then the risks increase (example in Figure 4). Lateral corrosion of the casing can be relatively quick (10's of years) followed by buoyant transport of CO₂ rich fluids inside the casing. The other casing strings still have to be penetrated with diffusion limiting the reaction rate but only lateral casing corrosion is required to effect a migration into the upper strata. From here, the buoyancy-derived over-pressure may be sufficient to break down formations or lateral migration may lead to the CO₂ leaking into the sea at a subsea outcrop.

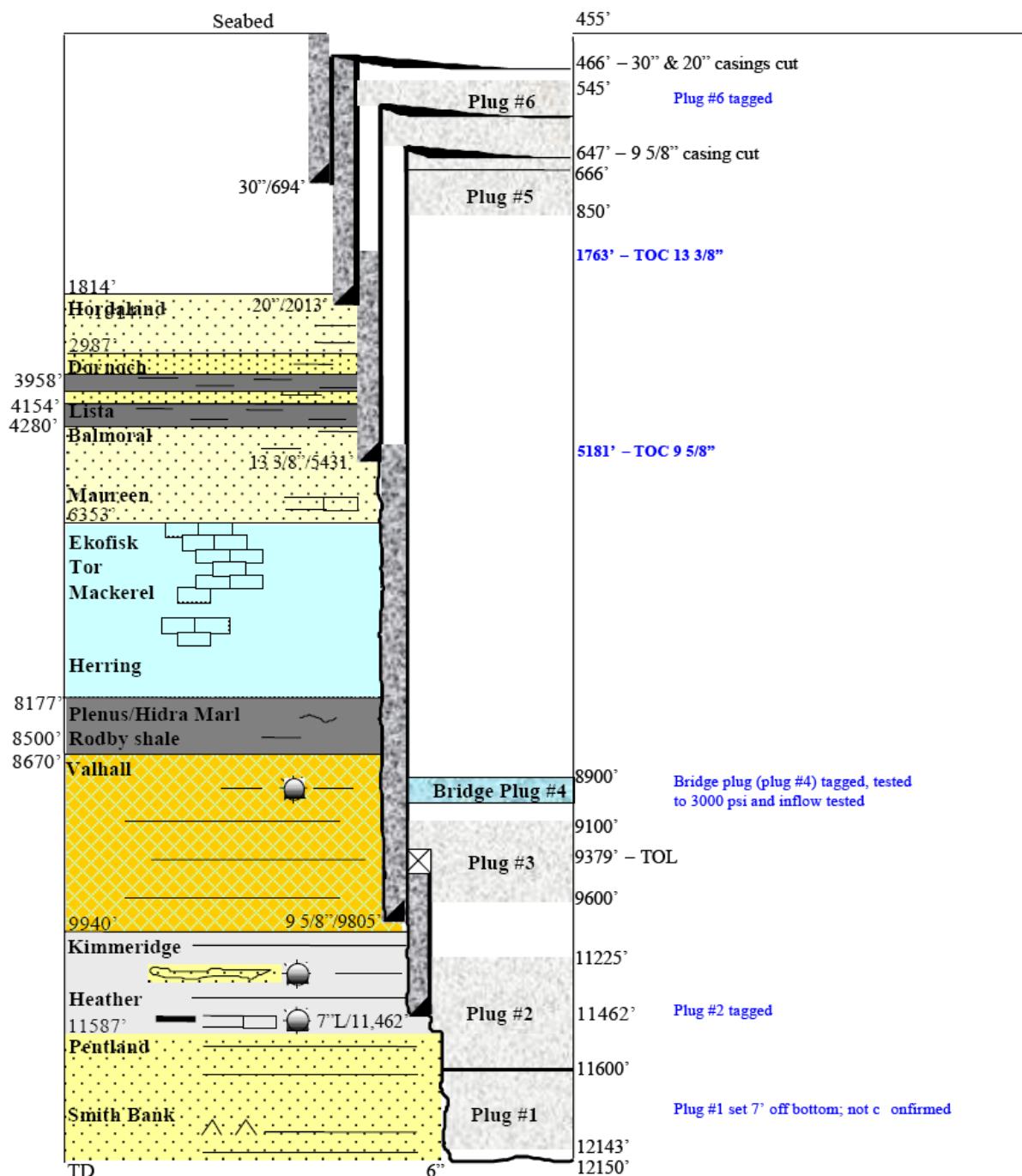


Figure 4 – Moderate Abandonment Practice (20/4b-4) – Cemented Casing but no Internal Cement Plug across Cap Rock

An example of poor abandonment practice is shown in Figure 5. The reservoir cap rock (Rodby shale in this case) does not have an internal cement plug across it.

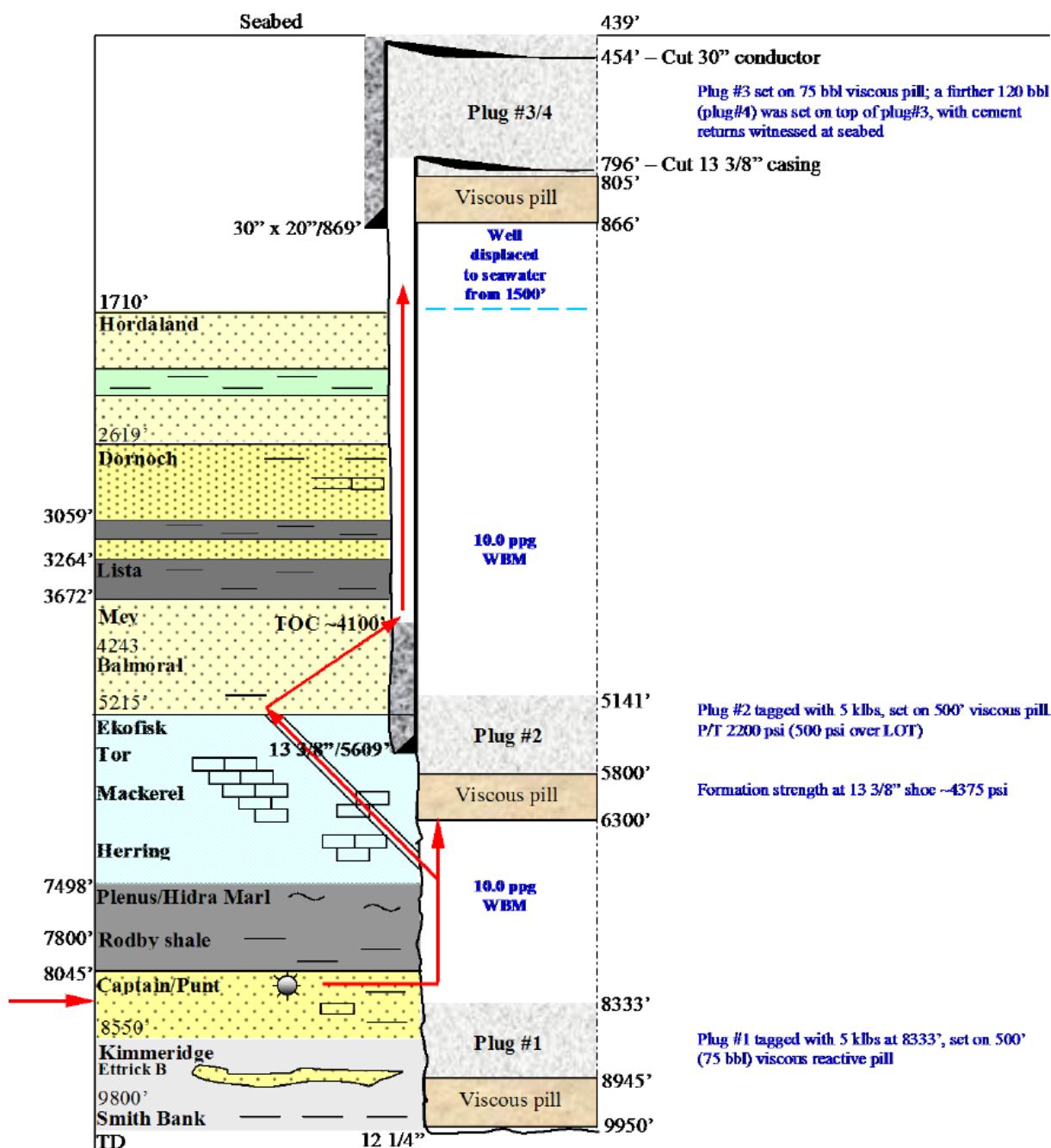


Figure 5 – Poor Abandonment Practice Example (Well 14/28b-4)

2.3. Probability of an Individual Well Allowing CO₂ Migration

Determining the generic probability of an individual well allowing CO₂ migration is extremely hard as it depends on the type of abandonment, the migration pathway to the well and the overpressure at the well.

LeGuen et al (SPE 122510, "A Risk-based Approach for Well Integrity Management Over Long Term in a CO₂ Geological Storage Project") analysed 1296 possible generic failure scenarios per well for several abandoned well scenarios (not North Sea specific) and

although they included so many leak pathways, the critical pathways were indeed identified as through the cap rock. Well and geological specifics, not surprisingly, made a large difference. The synthetic well they used represents a scenario similar to Figure 4 – i.e. a mid-case. The pressure in the reservoir adjacent to the abandoned well was however significantly over-pressured (possibly more so than even a typical aquifer injection scheme and certainly more than a depleted gas reservoir scheme). This is important as without any injection over-pressure, there is no drive mechanism (beyond a small capillary effect) for pushing CO₂ into an open well as the well will be full of mud or brine at the pressure of the surrounding formations.

The probabilities of many of the leak paths creating migration of CO₂ into the aquifer are given from the modelling as less than 0.001 over a 1000 year time frame. However, some of the leak paths give probabilities that are between 0.001 and 0.01. It is these probabilities along with the associated leak rates that will be used in this analysis. Assuming an average probability of 0.005 per migration pathway with 50 different migration pathways per well identified with this probability at the highest severity level this equates to a probability of around 0.22 [i.e. (1-(1-0.005)⁵⁰)] over 1000 years. In many cases, such a probability would not be considered acceptable. However the abandonment analysed does represent a scenario where the risk relates to a breakdown of the cement and casing laterally rather than vertically. It is clear that wells abandoned in such a way should be avoided where possible – this can preclude several potential abandonment sites as rectification costs and risks are high.

In the same manner, the modellers also assessed the impact of a better quality abandonment with full rock-to-rock cement plug across the cap rock. This marginally reduced the probabilities of migration but had a very significant effect on the magnitude of the migration.

It is possible that in a saline aquifer storage system, the aquifer could be deliberately depressurised by a water production well. This reduces the overpressure and therefore the leakage potential from other abandoned wells and can be used to direct the plume of CO₂ away from certain locations. It is however a further source for leakage (CO₂ breakthrough) during the CCS injection phase or once abandoned but can be specifically designed to mitigate such risks.

Some adjustment will be required for the case of a depleted gas field – without any strong justification, a reduction in probability by a factor of 10 has been used based on the lack of drive mechanism – modelling should be used to back up this estimate. This could be quantified using the same approach used in SPE 122510 but has not been attempted.

Note that the probability of CO₂ migrating to an abandoned well is not included. This probability of CO₂ reaching an abandoned well is included in the well numbers (Section 2.4).

2.4. Numbers of Wells Likely to be in Region of CO₂ Plume

Looking at a North Sea well population, there have been approximately 10,000 wells drilled in the UKCS since 1964. Assuming that wells not yet abandoned in the vicinity CO₂ storage complex can be abandoned to reduce the risk of CO₂ migration to an insignificant level, this only leaves the exploration and appraisal wells – some 4,100. Looking at fields such as Goldeneye, and using a similar strategy – including wells within 3-5km of the field boundary, the number of abandoned wells is estimated to be 6-12 per field. However the structural / stratigraphic closure of the accumulation in which the storage takes place will reduce the likelihood of CO₂ reaching the abandoned wells out with the field. Some degree of fingering of CO₂ can still occur if permeability contrasts are unfavourable. Accounting for the location of wells with respect to the spill point(s), a rather arbitrary reduction to an average of 6 abandoned wells per site within reach of a CO₂ plume has been assumed.

For saline aquifers where there is less likelihood of nearby appraisal wells (some exploration wells), the well densities are estimated to be less and an average of 3 abandoned wells is assumed.

2.5. Overall Probability of any Migration via an Abandoned Well

Assuming the probability of migration to an upper horizon outside the storage complex of 0.22 over 1000 years for a saline aquifer well and 0.022 over the same period for a depleted gas reservoir (from section 2.5) and 6 wells contacted by the CO₂ plume, the probabilities are:

- Saline aquifer about 0.5 [i.e. $(1-(1-0.22)^3)$] over 1000 years.
- Depleted gas reservoir 0.12 [i.e. $(1-(1-0.022)^6)$] over 1000 years.

Note that although these figures might appear high, it should be remembered that migration out-with the well does not necessarily mean migration into the biosphere and rates may be so low (less than 1% of the storage volume as explained in Section 2.6) as to be both undetectable and of no major concern.

2.6. Rates of CO₂ Migrating to Surface

The rates of CO₂ migration are again very dependent on the details of the leak path and not just on any migration past the cap rock. To migrate out of the well, flow through some extremely tight system is required (cement whether degraded or not is extremely low permeability for example).

2.6.1. Abandoned Exploration, Appraisal or Production Wells

Using the severity indexes outlined by Le Guen (SPE 122510), the migration rates for an over-pressured reservoir (i.e. saline aquifer) and the abandonment process similar to Figure 4 are of the order of 1% of the total stored volumes over 1000 years. This is a very low rate (approximately 1/5000 of the injection rate) as the leak path is highly restrictive. Assuming a stored volume of 500 Mte, this equates to a loss of 5 Mte. This estimate is also considered a high case as it assumes a significant overpressure and this overpressure endures. This is pessimistic. The migration pathway out of the well will also influence the ability of the surrounding formations to buffer or store these.

There is no similar analysis for a depleted gas reservoir, but given the dependency of migration on overpressure, I would suggest that the rate would be an order of magnitude (or more) less than the 1% (i.e. <0.1%). Assuming a depleted gas storage reservoir volume of 200 Mte, this equates to a loss of 0.2 Mte.

2.6.2. Abandoned CO₂ Injection Wells

Given the higher standard to which wells can be abandoned where they are currently accessible, a much lower migration rate can be used. The Le Guen analysis suggests a maximum of 0.05% migration rate (of the total injected mass of CO₂) over 1000 years for wells with full rock-to-rock cement plug across the cement plug. For wells without an underreamed section through the cap rock but a cased and cemented section with good quality and height of cement and an internal cement plug of adequate height the migration rates would be slightly higher.

2.7. Remedial Measures and Timeframes for Repair

The majority of migration pathways of CO₂ to the biosphere through an abandoned well are via a tortuous path such as cement to rock micro-annuli or through barely permeable cement. As such, migration rates are extremely low. For the scenarios analysed by Le Guen et al (SPE 122510) even in the scenario of an abandoned well with little internal cement across the cap rock, the migration rates are such that the majority, if not all, the migration would be absorbed by porous formations external to the well. Migration to surface is unlikely or at most a few bubbles at some point away from the abandoned well. It is unlikely that any remedial measures would be cost effective. In theory, if a significantly leaking abandoned well could be detected, it could be repaired by a newly drilled well intersecting the abandoned well in the exact location of the cap rock. The cost and risk of such an operation (probably in the order of £ 25-30 million per well) would have to be weighed against the benefit (value of CO₂ isolated). Such a repair could be undertaken within approximately three to six months once the leak had been detected and then the offending well identified.

3. CO₂ Injection Wells

CO₂ injection wells are different from abandoned wells in two critical aspects:

1. They will have been designed specifically for CO₂ injection service. Even if their original purpose was hydrocarbon extraction (depleted gas reservoirs), the wells will have been transformed (worked over) prior to injection duty to ensure that they are fit-for-purpose.
2. During injection service and for a period of time thereafter, the integrity of the wells will be monitored (measurement, monitoring and verification – MMV plan) and any repairs made prior to any likely migration of CO₂ out with the well.

They are exposed to greater CO₂ concentrations and greater pressure and temperature fluctuations than an abandoned well. However, a competent drilling and completion design will take this into account.

3.1. Description of Problem

For CO₂ to leak from the storage complex requires failure of well integrity and migration through or around multiple rock strata (some of which may act as barriers). Leakage from the storage complex may then be possible. For CO₂ to migrate from the containment of the injection well requires failure of multiple barriers.

The probability of a leakage can be assessed by analysing the probability of the failure of individual barriers, using CO₂ injection sites and analogues as a guide. Some individual failure modes are detectable and potentially resolvable within a timeframe that prevents further migration. Leakage requires a failure of all of the barriers. Some of these barriers may be fully independent, some will have a degree of dependence – i.e. migration through one barrier increases the probability of a further barrier breaking down.

3.2. Migration Pathways

Modern well designs suitable for either hydrocarbon or CO₂ injection service largely adhere to the “double barrier philosophy”. Some exceptions may exist related to the integrity of the cap rock and adjacent cement.

Figure 6.6 shows a typical offshore production or injection well with the associated primary (red line) and secondary (blue line) barriers. UKCS CO₂ injection wells are unlikely to be significantly different e.g. Goldeneye CCS completion design proposal (ref UKCCS - KT - S7.16 - Shell - 004 Well Proposal April 2011 ScottishPower CCS Consortium).

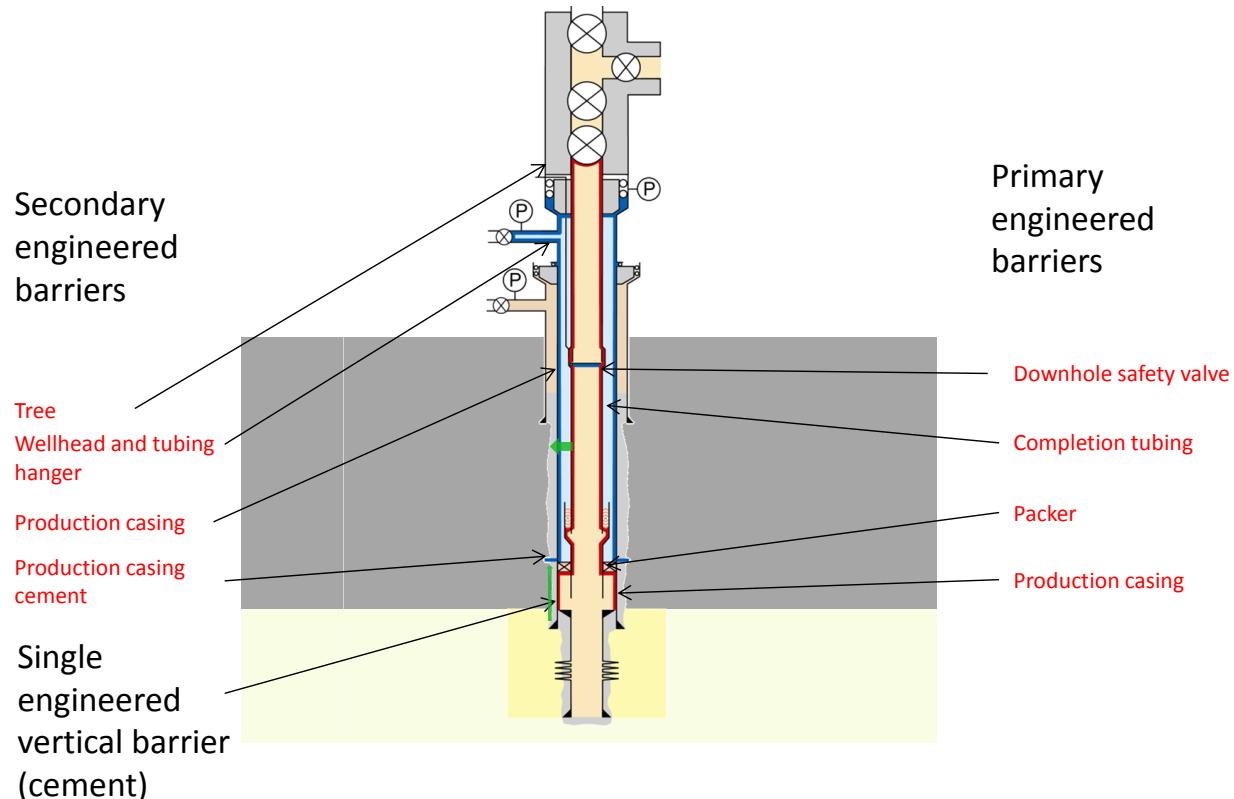


Figure 6 – Typical Hydrocarbon Production / Injection Well (© J. Bellarby 2009).

The primary engineered barriers between CO₂ in the reservoir and the biosphere typically consists of:

- The production casing below the packer
- The packer and associated seals
- The tubing and associated hardware
- The tree or downhole safety valve

The secondary engineered barriers are typically:

- The cement adjacent to the production packer
- The production casing above the production packer
- The wellhead, tubing hanger and associated seals
- The tree or downhole safety valve

The migration pathways out of the well are:

1. Failure of the primary barrier followed by failure of the secondary barrier. Note that failure of the primary barrier on its own does not constitute a leak as containment is still within the storage complex. Allowance is made in terms of probability and severity for the location of the migration pathway (deep vs. shallow for example).
2. Failure of the single barrier (cement) adjacent to the cap rock. This is still a leakage from the CO₂ reservoir via a well but although technically a single barrier, there are nevertheless multiple potential barriers and baffles still to be overcome before CO₂ escapes to the biosphere

Generally in both cases, leakage from the storage complex additionally requires migration through or around strata above the reservoir. The exception being in the first case where the secondary barrier lost includes the wellhead.

3.3. Probability of Individual Well Allowing CO₂ Migration

3.3.1. Primary Well Barrier

The primary well barrier is the barrier exposed to injection fluids. The barrier comprises the casing or liner below the packer, the packer itself with any associated seal or travel joints, the tubing and the downhole safety valve.

The reliability of such a system for hydrocarbon production duty is very variable. Analogue data from the 8 fields on the Norwegian Continental Shelf via the research institute SINTEF can be used (ref P. Randhol and I Carlsen "Assessment of Sustained Well Integrity on the Norwegian Continental Shelf"). Such data is likely to be similar to the UKCS. The data suggest that tubing to annulus communication (i.e. a leaking primary barrier) accounts for 30% of the reported leaks. Given that detecting any significant leak of the primary barrier is relatively straightforward (by monitoring the annulus pressure), this number can be used reliably. Over a ten year period, the percentage of wells reported with problems was 18%. This appears higher than onshore wells. In Alberta, Canada (M.M. Hossain et al (SPE 133830)), the figure quoted is 6% of 300,000 wells with a preponderance to failed barriers (and sustained casing pressures) close to surface. The lower percentage for onshore wells may be related to the definition of a failed barrier, the detection of such failures or better integrity. The closer analogue to the UKCS is Norway and this will be used here.

The trend in Norway was for a greater number of leaks in older wells – suggested to be caused primarily by corrosion. Using this data as an average, the incidence of failure of the primary barrier is approximately 0.5%/well/year (i.e. 30% x 18% / 10). The incidence of leaks in injectors is higher. There are 2 reasons for these leaks – the vast majority of the injectors are for water injection. Such wells can be highly corrosive (dissolved oxygen) and the oxygen is notoriously difficult to reliably remove. The metallurgy is rarely suitable for dissolved oxygen – especially looking back on the time frame of the survey; 1998 – 2007. The second reason is that sealing systems were often not adequately designed for the cyclic loads (pressure and temperature fluctuations). It is therefore suggested that the hydrocarbon production environment provides the closest analogue with a similar approach to selecting materials appropriate for a field life. Indeed, it could be argued that the figure used is a high-side estimate, especially given that a CO₂ injection well will be designed for that purpose. Dr. L. Smith et al (SPE 136160) analysed the materials used for various CO₂ injection schemes and identified various failures. In Texas, in CO₂ WAG (Water Alternating Gas) applications, plastic or lined carbon steel is used with limited success. WAG wells are significantly more aggressive than CCS wells as CO₂ is only corrosive in the presence of water. Gas with lined or coated tubing is also at risk of blistering attack due to gas percolation. Such failures could have been prevented. Statoil use 25Cr Duplex material for Sleipner and this is corrosion resistant to CO₂ (and contaminants) even in the presence of water. However in Snohvit, carbon steel is used (AISI 4140). This is believed to be due to very low temperatures and a resulting fracture risk with other materials. Indeed for CO₂ injection into depleted gas reservoirs, injection temperatures can be as low as -40°C due to the phase change from liquid to gas.

Regardless of the injection conditions (temperatures, pressures, fluids and contaminants) and the materials (steels, other alloys, elastomers and plastics), a rigorous selection process would be carried out (similar to Goldeneye's analysis (UKCCS - KT - S7.16 - Shell - 005 Well Functional Spec) to reduce the risks of primary barrier failure.

3.3.2. Secondary Well Barrier

Assessing the probability of the secondary barrier failing is harder than the primary barrier failure. It is both harder to detect and also it may only leak once the primary barrier has failed (harsher fluids and pressures). The recorded statistics do not distinguish between the

two. In many water injection well cases, injection continues even when the primary barrier fails (the risk of hydrocarbon escape is very low – but not zero).

Again the evidence is that injectors are more prone to leakage but this has been discounted for the same reason as it was discounted for the failure of the primary barrier.

The fact that the incidence of failure of secondary barriers is probably under-reported whilst the statistics are skewed towards a high failure rate due to the incidence of corrosive water suggests that the quoted figure of 8% is appropriate.

The failure rate for the loss of the secondary barrier is therefore 0.15%/well/year. This rate will be assumed independent of the loss of the primary barrier as in CO₂ storage, the secondary barrier will be rated to the same requirements as the primary barrier (unlike many production or water injection wells) and continued injection will not proceed if the primary barrier has failed.

3.3.3. Failure of Primary and Secondary Barriers (Safety Valve and Tree)

The discussion so far has assumed that migration from the containment of the well is lateral i.e. through tubing and casing. A further migration route is through the safety valve and tree. The failure modes of the safety valve or tree during CO₂ injection service is unlikely to be much different from hydrocarbon service so long as both components have been designed and selected with the specific services of CO₂ in mind. Temperatures can be extremely low during certain CO₂ injection operations (especially for depleted gas reservoirs where a phase change is likely in the tubing), and this needs to be accommodated in the well completion design.

Using the Norwegian database of safety valve and wellhead / tree, a failed downhole safety valve is the cause of approximately 30% of leakages and a wellhead (assumed to include the tree) is the cause of a further 30% of leakages. This gives a failure rate of 0.9%/well/year and a mean time to failure of approximately 111 years for each component. Note that these statistics are not the failure rate for the safety valve and tree but the failure rate where the failure mode is failing to hold pressure from the reservoir. For example, failure rates for all failure modes of the downhole safety valve are typically around 5.5%/well/year (source SINTEF database for UKCS completion equipment) but the majority of failure modes are failing to open rather than failing to close.

3.3.4. Migration Vertically through Cement adjacent to Cap Rock

There are no known statistics regarding the failure of the cement adjacent to the cap rock. There are case studies where this has occurred including some on hydrocarbon gas injection service. Case studies usually identify the problem as being caused by a poor cement job adjacent to the cap rock combined with injection overpressures rather than degradation of cement. Fracturing around the cement job is covered separately in Annex A2 to this report. Assuming that deliberately accepting a poor cement job is ruled out as part of the injection qualification process by running a cement bond log and analysing the cementing records, this leaves the theoretical risk of cement failure by chemical attack or inadvertently accepting a poor cement job.

CO₂ resistant cements are available and it would be expected that new wellbores designed explicitly for CO₂ would be constructed for these. However the reaction rate of CO₂ with a conventional Portland cement is limited by diffusion and depleted gas reservoirs would likely use existing wells. Where core has been recovered through the cement – shale interface (SACROC program) from CO₂ injection sites, integrity can be assured for decades in a vertical direction (assuming even only a few metres of good cement) but eventual failure in a lateral direction (along with corrosion of the casing) is possible. What remains as risk therefore is inadvertent acceptance of a good quality cement job combined with overpressures (pressures above original reservoir pressure) caused by local injection and

limited chemical attack. Anecdotal evidence suggests that a poor enough cement job that could lead to migration past the cap rock probably occurs in less than 1% of wells. The chance of accepting such a cement job as good are reasonably high (say 10%) due to well-known problems with cement bond log interpretation. Both these numbers are highly subjective. Assuming an injection period of 20 years, this provides an annual probability of failure of 0.005% /well/year (i.e. $1\% \times 10\% / 20$).

No differential in probability is placed between a depleted gas reservoir and a saline aquifer storage site. The differences probably balance out – saline aquifer wells will likely be newly designed and constructed with CO₂ duty specifically in mind. By their very nature however, saline aquifers will need pressures greater than the original reservoir pressure to create injection and storage. On the other hand, depleted gas reservoirs will likely never go above the original reservoir pressure but will reuse existing well stock (if fit-for-purpose).

3.3.5. Further Migration following Loss of Cement Integrity adjacent to Cap Rock

Migration past the primary reservoir seal (i.e. cap rock) does not equate to migration out of the storage complex. It is likely that secondary reservoirs and secondary seals provide either a complete or partial barrier. The migration route and the effect that this will have on leakage rates is considered in Annex A2.

3.4. Numbers of Wells Likely to be used for CO₂ Injection

The numbers of wells to be used for injection on any CCS project will depend on the scale of the project and the rate of CO₂ sequestration. Using the Longannet / Goldeneye scheme as being typical, this equates to 5 wells on injection duty. Larger schemes or those with quality reservoirs may have more. Pilot programmes or CO₂ disposal as part of hydrocarbon production (e.g. Sleipner) will be limited to 1 or 2 wells. For the purpose of this study, we have assumed 5 wells in a CCS project.

3.5. Overall Probability of any Migration out of an Injection Well

3.5.1. Injection Duty

3.5.1.1. Lateral Migration through Primary and Secondary Barriers

It is not appropriate to simply multiply the probabilities of the failure of the primary and secondary barriers to estimate the probability of failure of well integrity. Neither is it correct to simply add in the probability of the failure of the cement barrier adjacent to the cap rock.

For a secondary barrier failure to have any material effect, the primary barrier must at this point also have failed. This does not mean that the failures have to occur simultaneously, simply that a failure in either barrier is not remediated in a timely enough manner that the two failures overlap.

Detection of a primary barrier failure would be near immediate (a few days at most) due to continuous or daily monitoring of annuli in an offshore environment. A fix for a leak could involve anything from a straddle operation through the existing completion or a full workover. The lead time for such might be in the order of 3-4 months. Any longer, and operators would likely commit to temporarily plugging the well. With the previously assumed failure rate of 0.5%/well/year this is a mean time to failure (MTTF) of the primary barrier of a single well of 200 years. The well would then be exposed for 1/3 year (4 months) or $0.3333/200.33 = 0.0016$ of the time if a secondary barrier were to fail (0.15% /

well/year). This gives a combined failure rate of primary followed by secondary barriers of 0.00025%/well/year.

It is also possible that the secondary barrier could have failed and not been remediated prior to the primary barrier failing. Given that detection of the secondary barrier failing would be more dependent on pressure testing of the barriers (there being minimal pressure differences normally). Such pressure testing is not a regulatory requirement in the UKCS but is good and common practice if there are concerns over well integrity. Assume that such testing is performed every 6 months but that any remedial activity is not performed for a further 6 months (repairing the secondary barrier is an expensive and time-consuming process and would likely require a rig). Again, any longer and the well would likely be temporarily plugged awaiting repair or safe abandonment. With a MTTF of the secondary barrier of 667 years (failure rate of 0.15%/well/year), this gives an open secondary barrier of $1/668 = 0.15\%$ of the time. The failure rate of the primary barrier is 0.5%/well/year so failure rate for secondary followed by primary barrier failure is 0.00075%/well/year.

The total failure rate for lateral migration out of the wellbore is therefore 0.001%/well/year.

3.5.1.2. Vertical Migration through the Tubing (Safety Valve and Tree)

The repair time for a downhole safety valve is similar to a leak in the tubing with a variety or through tubing and rig based options available. We can assume that the well would be repaired within 4.5 months, based on a test frequency for the downhole valve of 3 months (average period undetected = 1.5 months) and the valve repair time of 3 months. This equates to loss of downhole safety valve for $0.375/111 = 0.00338$ of the time. The tree leakage rate is also 0.9%/well/year. The overall combined failure rate for downhole safety valve failure followed by tree failure is therefore 0.003%/well/year.

A tree failure would be detected much more immediately if the leakage was an escape into the environment. The well would be shut in and then plugged for repair of the tree. The plugging would typically take 1 month (including mobilisation and planning). Meanwhile although the CO₂ is not escaping to the biosphere, there is only one barrier (downhole safety valve). This equates to non-availability 0.00075 of the time. The combined failure rate for tree followed by downhole safety valve is 0.00068%/well/year.

The overall failure rate for coincident loss of both the tree and the downhole safety valve is 0.0037%/well/year.

3.5.1.3. Multiple Wells

Assuming 5 wells in a CCS project, this provides an overall failure rate of 0.005%/year.

With a 20 year injection life, there is a probability of 0.1% of a well failing and CO₂ migrating out of the storage site. This still does not imply leakage out of the storage complex as the CO₂ still has to migrate to surface and into the biosphere.

3.5.2. Abandoned Injector

An abandoned injector will be treated the same as any abandoned well albeit with a generally higher standard of abandonment.

3.6. Rates of CO₂ Migrating to Surface

The rate of migration will be dependent on where the leak occurs. Generally the higher up the well, the greater the rate – flow is easier through the well than through the rock layers. The worst case would be failure of the secondary barrier (production casing) close to surface

with failure of the primary barrier deep down e.g. failed tubing just above the packer. This gives the greatest flow area.

Using flow modelling software (WellCat) with a 3000m deep, normally pressured reservoir and 9 5/8" casing with 5.5" tubing and flow up the annulus between the casing and the tubing and no restrictions at any of the leak points, the maximum rate is around 4.5 Msm³/day (million standard cubic metres per day). Figure 7 shows these pressure drops for 3 and 4 Msm³/day. At 5 Msm³/day, there is no solution – pressures drop below atmospheric pressures due to high frictional pressure drops between the reservoir and the surface.

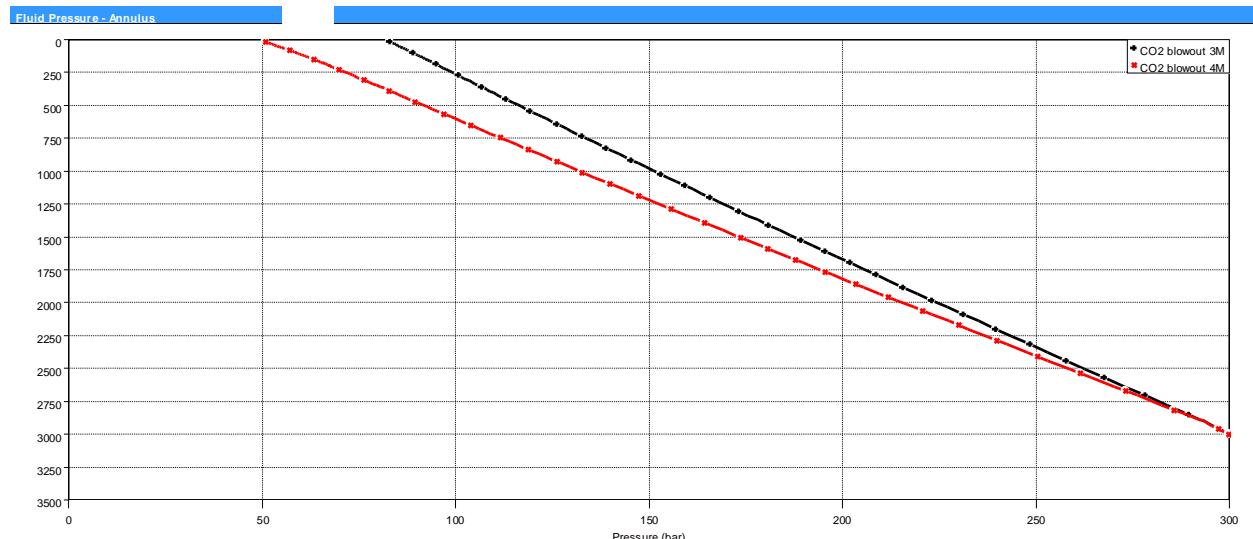


Figure 7 – Pressure Drops for CO₂ Flowing up the Annulus

For a leak in the tubing at surface the rates are around 2.5 Msm³/day through 5.5" tubing (4.5 te/day).

For a leak deeper down, the rates will be lower and more dependent on the migration through the formation – see Annex A2. This also applies to migration via degraded cement adjacent to the cap rock.

3.7. Remedial Measures and Timeframes for Cessation

If migration to the biosphere occurs and is detected then there are a number of short term and long term measures that can be taken depending on the leak location:

1. If the offending well can be identified e.g. from the pressure response or by sequentially shutting in individual wells then the offending well would be shut-in – at surface and at the downhole safety valve. The majority of leaks of the tubing would likely be close to surface (highest loads on the tubing and greatest opportunity for corrosion by contamination with oxygen). Such a leak would therefore be isolated and likely within 1 day (probably hours if the leak is via catastrophic failure of the well). With a typical downhole safety valve depth of 500m, a leak above the safety valve might account for around 75% of the tubing leak cases.
2. If the complete well integrity is breached by a failure of the primary barrier below the safety valve, the rates will likely be higher (Section 3.6) and the remedial measures harder. The well would be killed by injection of kill weight muds down the tubing or annulus (top kill). This assumes that access to the wellhead is possible and that suitable pumping and storage equipment is either available at the platform or can be brought in. Given that the leak is not directly at the wellhead / tree this is

- likely possible with an estimated duration from start of leak to cessation of approximately 1 month.
3. For a complete loss of well integrity via the tubing (downhole safety valve and tree failure), the remedial measures will be made harder by lack of direct access to the wellhead. It is possible that a relief well would be required if a top kill is unsuccessful (suggested as 50% of the time). A relief well could take up to 6 months to plan and execute – with a top kill perhaps 1 month. Average time = 3.5 months.
 4. For a migration around or through cement, the action would depend on the level of threat. It is theoretically possible to remediate a leak in this location by killing the well and then milling the casing in the region of the cap rock and placing a full width (rock to rock) cement plug. Such an operation would likely take around 3 months.