REPORT ON

WELL BORE INTEGRITY WORKSHOP

Date: 4\textsuperscript{th} to 5\textsuperscript{th} April 2005

Marriott Woodlands Waterway Hotel and Convention Center, Houston, Texas, USA

Organised by IEA Greenhouse Gas R&D Programme and BP

with the support of EPRI
SUMMARY

The integrity of well bores, their long-term ability to retain CO₂, has been identified as a significant potential risk for the long-term security of geological storage facilities. A workshop was held in April 2005 to bring together over 50 experts from both industrial operators and from research organisations. Industrial operations are part of CO₂ enhanced oil recovery (EOR) projects or acid gas waste disposal projects. Current research includes laboratory investigations that attempt to simulate long-term geochemical and mechanical processes that may affect well completion materials – mainly cement; field studies of well completions that have been exposed to CO₂ during industrial projects as described above, and modelling studies, both of local reactions and upscaled simulations of leakage across basins.

Key findings of this workshop include:

• Ensuring well integrity over long timescales has not been attempted before and represents a new challenge to the oil and gas industries.

• It will not be possible to promise a leak-free well, but rather we should emphasise that we can build wells employing state-of-the-art technologies which will reduce risks.

• Portland-based cements will react with CO₂, leading to cement degradation. The main reactions involve carbonation of the major cement components – Portlandite and calcium silicate hydrates which are converted to carbonate minerals such as aragonite, calcite and vaterite.

• Degradation results in a loss of density and strength and an increase in porosity.

• Laboratory experiments of these reactions are able to simulate those observed in wells that have been exposed to CO₂ in EOR injection and production wells. However, the degree of reaction (i.e. the rate of reaction) may not necessarily be comparable between laboratory and field. This may be due to the need to speed up laboratory experiments, often by increasing temperatures, to reproduce longer timescales.

• Although a coupon of portland cement will dissolve within days or weeks of being exposed to CO₂ in the laboratory, in a wellbore setting the limited
permeability of the rock adjacent to the well bore limits mass transfer and corrosion rates. Getting a better understanding of the carbonic ion mass transfer rates under different scenarios is a key area of work.

- One, two and three dimensional models are now being developed to simulate processes observed both in the laboratory and in the field, at the small scale of specific leakage mechanisms within a well and also over the larger scale examining broad leakage on the basin-scale.

- However, we are unable to use these models in a predictive sense due to a lack of detailed knowledge on specific issues, discussed below in the key research needs.

- New cements have been developed and deployed that reduce the amount of alteration caused by acid attack. These cements either reduce the proportion of Portland-based cement in the mix, add inhibitors or use completely new calcium phosphate-based cements that do not contain any reactive portlandite.

- Studies of well completions from CO$_2$ EOR operations were recognised as offering significant valuable data on real failure processes and consequences. Although these offer the longest “experiments” to date, timescales are still limited to a few decades.

- Initial requirements for a R&D program to investigate such well completions and the types of analyses that could be made on retrieved samples, has been proposed in this meeting.

- Important information could be obtained from areas where it is not possible to obtain cement samples from wells (poor cementing or subsequent degradation could be possible explanations).

- Some of the most desirable potential storage sites are hydrocarbon fields, which have proven traps and the potential for tertiary enhanced recovery. However these same sites are also penetrated by numerous wells which could be susceptible to corrosion. The permanence of CO$_2$ storage at such sites may therefore not be as high as originally thought.

Key research needs:

- An early requirement is to adequately define criteria against which failure may be judged. Several suggestions were made during the meeting,
primarily involving leakage to various parts of the system (i.e. overlying reservoirs, potable water bodies such as aquifers or the atmosphere).

- Data is required on the frequency of well failures from the hydrocarbon industry to constrain models and estimates of risk. Such data may be obtained from regulators and industry.
- A detailed understanding of the mechanisms of cement degradation and leakage within well completions is needed. There is considerable effort in this area from industry.
- The consequences of a well failure need to understood as these will help to define design criteria, monitoring protocols and risks.
- Standard procedures to test the long-term performance of well completions are needed.

The following next steps were identified:

- Presentations from this workshop and copies of this report are available at www.co2captureandstorage.info/techworkshops/techwkshop.htm. A password is required.
- Establishment of a working group on wellbore integrity.
- Suggestions for discussion topics at a future workshop include:
  - Defining well failure
  - Standardising testing procedures
  - Industrial and regulatory evidence for failure frequencies
  - Designing a R&D programme to obtain evidence from existing CO₂ EOR operations.
  - Designing monitoring procedures.

This report was written by Jonathan Pearce, British Geological Survey, Keyworth, Nottingham, NG12 5GG, United Kingdom, on behalf of the IEA Greenhouse Gas R&D Programme.
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1. INTRODUCTION

This report summarises a workshop on wellbore integrity for the long term geological storage of CO₂ that was jointly organised by the IEA Greenhouse Gas R&D Programme and BP with the support of EPRI. It was chaired by Dr. Charles Christopher of BP America and brought together 50 delegates from research institutes and industry. The workshop was held at the Marriott Woodlands Waterway Hotel and Convention Center, Houston, Texas, USA on 4th to 5th April 2005.

This report was written by Jonathan Pearce, British Geological Survey, Keyworth, Nottingham, NG12 5GG, United Kingdom, on behalf of the IEA Greenhouse Gas R&D Programme.

Workshop aims and objectives

The integrity of wellbore cements to CO₂ rich environments has been raised as an area of some concern with respect to the long term effectiveness of CO₂ storage in geological reservoirs. This workshop aimed to bring together the main research groups that are currently studying the effects of CO₂ on wellbore cements, with industrial groups who have been working with CO₂-rich environments for many years.

The objective of the workshop was to assess the current state of knowledge on the integrity of wellbore cements exposed to CO₂ and to address the key future research needs in this area. In so doing, the workshop aimed to develop a picture of how significant, if at all, the effect of CO₂ on wellbore cements will be post-storage and if well bores do pose a significant risk of CO₂ leakage in the future.

Workshop Attendees

The workshop was attended by over 50 delegates from 33 organisations and 6 different countries. The attendance list is given in Appendix 1.
Workshop outcomes

It was expected that the workshop would:

- Lead to the establishment of a working group on well bore integrity that could feed into activities underway on risk assessment,
- Help to develop a list of research needs for assessing well bore integrity in CO₂ rich environments,
- Provide a source of information that can be conveyed to stakeholders.

Workshop Programme

The agenda is given in Table 1. The workshop covered the following topics, over two days:

- Experience from the CO₂ industry
  Presentations were made by industrial project teams that have been working with the design and maintenance of CO₂ enhanced oil recovery (EOR) injection and production wells or sour gas disposal wells, mainly in the US.
- Current research into CO₂ interactions with wellbore materials
  Presentations by research groups covered a range of research activities that are currently underway to understand and improve the long-term performance of wellbore materials based on field and laboratory-based experience.
- What has been learnt?
  Facilitated breakout sessions allowed delegates to reflect and discuss previous presentations. The following questions were posed to each group to stimulate discussion:
  - Do well bores represent a significant leakage risk from CO₂ storage reservoirs?
  - Do we know how to reduce the risk of CO₂ degradation of well bore cements?
  - Are there standard industry methods to minimise leakage from well bores?
  - Is leakage easy to remediate if it occurs?
• What further work is needed?
Table 1. Wellbore Integrity Workshop Agenda

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<tr>
<th>Time</th>
<th>Session</th>
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<tbody>
<tr>
<td>8:30</td>
<td>Introductions and Workshop Objectives – Charles Christopher</td>
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<td>8:45</td>
<td>Current Research Into CO2 Interactions With Wellbore Materials</td>
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<td>9:30</td>
<td>Sintef – Ider Akervall</td>
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<td>10:15</td>
<td>BREAK</td>
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<td>10:45</td>
<td>Schlumberger - Kamel Bennaceur</td>
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<td>11:30</td>
<td>Total - Pierre Brossollet</td>
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<tr>
<td>12:15</td>
<td>LUNCH</td>
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<tr>
<td>1:30</td>
<td>Modeling Wellbore Integrity</td>
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<td>2:15</td>
<td>Summarize learnings from the research – What do we know and what does it mean? Groups A and B.</td>
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<td>2:45</td>
<td>Report learnings and collate.</td>
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<tr>
<td>3:15</td>
<td>BREAK</td>
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<tr>
<td>3:45</td>
<td>Experience With Wellbores In CO2 Environments</td>
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<tr>
<td>4:15</td>
<td>Halliburton - Lance Brothers</td>
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<tr>
<td>5:00</td>
<td>Wrap-Up for the day</td>
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<tr>
<td>8:00</td>
<td>Plan for the day – Charles Christopher</td>
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<td>8:15</td>
<td>Oxy Permian – Tommy McKenzie</td>
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<td>9:00</td>
<td>Los Alamos National Lab – Bill Carey</td>
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<td>9:45</td>
<td>BREAK</td>
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<tr>
<td>10:15</td>
<td>Summarize Field Experience - What do we know and what does it mean?</td>
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<td></td>
<td>Groups C and D.</td>
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<tr>
<td>10:45</td>
<td>Report learnings and collate.</td>
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**Designs To Be Stable To CO2.**

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<th>Activity</th>
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<tr>
<td>11:00</td>
<td>ExxonMobil - Glen Benge</td>
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<td>11:45</td>
<td>Lunch</td>
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**The 1,000 Year Well**

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<th>Time</th>
<th>Activity</th>
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<tr>
<td>1:00</td>
<td>Based on what we know, what is required to design a well to be stable for</td>
</tr>
<tr>
<td></td>
<td>1,000 years? Groups A and B.</td>
</tr>
<tr>
<td>2:00</td>
<td>Report learnings and collate.</td>
</tr>
<tr>
<td>2:30</td>
<td>Way forward – what research needs to be done?</td>
</tr>
<tr>
<td>3:00</td>
<td>Adjourn</td>
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2. CURRENT RESEARCH INTO CO₂ INTERACTIONS WITH WELLBORE MATERIALS.


The presentation covered three areas of cement corrosion: development and testing of a model to explore coupled flow-mechanical-geochemical reactions, an experimental study of cement corrosion and comparison with cements obtained from a wellbore following prolonged exposure to CO₂ during industrial operations.

The greatest potential leakage route is through the annulus of a wellbore following acid attack on the well cement, well plugs and/or well casing. The annular gap between plugs, grouts and casing is therefore the primary focus of this research.

The Dynaflow model was used to investigate one-dimensional coupled flow-mechanical-geochemical reactions between cements, CO₂ and brines. It considers a variety of processes that may influence these reactions including CO₂ solubility and its controls (evaporation, salinity, pressure, temperature), transport of CO₂, evaporation, precipitation, compressibility of fluids and matrix, porosity and permeability changes and brine chemistry. Significant differences between CO₂ solubility and brine salinity from this model and previous literature results are attributed to correct treatment of solubility and evaporation processes, which reveals that evaporation reduces CO₂ solubility in the brine. Development of new algorithms allow 3-phase reservoir simulations which can include additional phases such as hydrocarbons, H₂S and CH₄. Future plans include extension to 2D and 3D simulations and inclusion of additional processes such as buoyancy, variable permeabilities and geochemistry to provide a model of leakage through the wellbore annulus.

Experiments have been conducted on cement pastes containing variable amounts of bentonite, to determine maximum reaction rates (flow-through experiments) and migration mechanisms (batch experiments). Samples were collected from Teapot Dome. Flow-through experiments indicate that within a few days calcium was removed and silicon reduced in a zone of increasing thickness around the outer margin of the cement rod, to produce a soft relict silica gel that could be easily
removed, with some armouring by calcite precipitation. Iron remained largely unchanged. This corrosion was strongly accelerated by lower pH and higher temperatures. Under typical conditions of a sandstone formation at ~1km depth, rate of attack would be ~2-3 mm per month if fresh acid flowed over the cement – this represents a maximum rate of reaction. In batch experiments, permeabilities of sandstones in contact with cement increased an order of magnitude, in contrast to limestones which showed little change. These results are now being compared with 19-year old cements from Teapot Dome which have been retrieved from 3000-5000’ (900-1500 m).

**Ider Akervoll, Sintef, Norway: Leaking well modelling and CO₂ interaction with cured well cement.**

A flexible reservoir simulation was constructed and used to evaluate the amount of CO₂ dissolved in porewater as a function of the aquifer pressure and temperature, and included a gas-water relative permeability hysteresis model. The effect of the critical gas saturation as a function of imbibition was investigated for a simplified Sleipner case. Dissolution of CO₂ in the aquifer water is the dominant mechanism of CO₂ storage in saline aquifers provided that the vertical communication allows for convective mixing of the CO₂ plume into the aquifer brine. The amount of trapped CO₂ gas due to the gas-water capillary pressure and relative permeability hysteresis decreases when k_v/k_h increases. The percentage of trapped gas is reduced to less than 30 % at a k_v/k_h ratio of 0.1.

Within the CO₂ plume, some convective flow may occur, which is largely dependent on the vertical permeability. Some bypass of convective flow may occur at the plume margins but this will be compensated for by the density effects of increasing CO₂ solution into the water. Low vertical permeabilities result in basal spreading of the CO₂ plume whereas higher vertical permeabilities, result in the plume spreading out under the caprock, as seen at Sleipner.

Currently no satisfactory and robust well model exists to model leakage through abandoned wells, following deterioration of cement plugs, with time and finite permeability and porosity. To get quantitative estimates of the leakage risk it is important to understand the mechanisms and time scales involved in such deterioration processes. It is possible to place production wells controlled at BHP at
various places inside the CO₂ plume and study how much leaks out. A simplified approach is to assume that all CO₂ entering the well will reach the surface controlled by the well inflow. Since no information about the well inflow is available the model has no predictive power except for studying the effect of different reservoir parameters for artificially chosen well inflow parameters. Modeling considered three locations for the leaking well: above the injection point (worst case leading to maximum CO₂ leakage), at 1.5 km and 2.1 km horizontally from the injection point. At 1.5 km 5-8% of stored CO₂ in the model was lost, compared to 3-4% at 2.1 km. The leakage rate is sensitive to the ratio of vertical to horizontal permeability, especially when the leaking well is at a greater distance from the injection point.

Cement curing experiments were performed to determine the effects of CO₂ on permeability and porosity. Cements were reacted at high pressures (300 bar, 30,000 kPa) and temperatures (150°C) which are not necessarily representative of CO₂ storage conditions and therefore need caution in extrapolating the results. A none-Portland cement supplied by Haliburton was used as a sealing cement. Following exposure to CO₂ the cement porosity increased from 34 to 39% and permeability increased slightly from 2.3×10⁻²⁰ m² to 3.4×10⁻²⁰ m². Mineralogical characterisation of the cement indicated that extensive dissolution of spherical particles occurred, especially on the sample surface, and that gehlenite (part of the calcium silicate hydrate matrix) was lost and calcite and aragonite were precipitated. Potential changes to the mechanical properties of the cements following reaction with CO₂, were examined by but little change was observed. The seismic properties were determined by the Continuous Wave Technique and the compressive strength determined from scratch tests. CO₂ Capillary entry pressures (140 mbar, 14Kpa) were not significantly affected by reaction with CO₂ for 4 weeks.

In conclusion, CO₂ corrosion of Portland cement is thermodynamically favourable and therefore cannot be prevented. The net result is leaching of the cementitious material from the cement matrix, increase of porosity and permeability, and a decrease of compressive strength. Downhole, this translates to a loss of casing protection and zone isolation. By adding pozzolans, the rate of corrosion can be reduced by as much as 50%. The long-term efficacy of the modified Portland cement systems remains to be seen. At best, such systems only postpone the
inevitable. More research is needed to develop truly stable, yet economically realistic, cements for this difficult environment.

Veronique Barlet-Gouédard, Schlumberger: Testing of CO$_2$ resistant material for well integrity under wet carbon dioxide supercritical environment.

Portland cements are not thermodynamically stable in CO$_2$-rich environments. For wellbores to provide long-term isolation and integrity for thousands of years, new materials need to be developed. This, in turn, requires the development of standard testing equipment in the laboratory and standardised testing procedures that accelerate the assessment of long-term durability. An experimental approach was taken to ascertain whether conventional testing can simulate actual conditions, what needs to be measured to quantify the carbonation process and determine how the carbonation of Portland cement proceeds under supercritical wet CO$_2$.

Reactions of the components of Portland cement with CO$_2$ were summarised, resulting largely in the formation of carbonate and bicarbonate, plus silica gel. Conventional testing using a sodium carbonate or bicarbonate solution results in very limited carbonation and doesn’t reproduce the acidic conditions of a CO$_2$-rich reservoir brine. Therefore batch experiments were conducted up to 500 bar (50,000 KPa) and 350°C, where stacked cement plugs were partially submerged in a CO$_2$-saturated water above which was a supercritical CO$_2$ atmosphere saturated with water. Following the experiment the fluid pH was determined, the cement plugs were characterised and those samples that straddled the CO$_2$ water boundary were analysed. X-ray microtomography was used to visualise the aragonite front that precipitated following reaction. Alteration zones up to 6 mm thick from the external surfaces developed after 3 weeks reaction. Carbonation occurs at a rate of 0.2 mm per day for a neat Portland cement. Scanning electron microscopy was used to determine porosity changes with depth which varied from +9% on the surface to a decrease of −2% at the carbonate precipitation front. Portlandite and calcium silicate hydrate cement matrix are consumed to produce carbonates, silica and water. Behind this carbonation front, the neoformed carbonate and silica are dissolved increasing porosity and significantly degrading the cement.
Alternative cements were also tested, including potassium phosphate-based material that contains fly ash and boric acid. Further ongoing work includes testing of a number of commercial cement systems, development and validation of an accelerated ageing test and modelling of the carbonation process in cements.

A need has been identified for industry to agree on the specifications for standard testing equipment to test the performance of wellbore materials.

**Glen Benge, ExxonMobil: A brief review of cement history, manufacture and use in oil industry.**

This brief presentation provided a background to the discussions of new cement applications for ensuring well integrity for thousands of years in a CO$_2$ storage facility. Cements have been used for thousands of years, though Portland cement was developed in the 1830s by Joseph Aspden. In the US, cements are classified into Types I-IV depending on grade and amount of water, which influence density and permeability. In the API, cements are categorised as A to D. Type C, for example, is sulphate resistant and Class A cements are primarily used in construction. Type G and H cements, mentioned in some of the previous talks, are used in the oil industry in the Gulf Coast. Type G is a finer version of Type H.

More water used in the cement mixture usually results in a cement with a higher permeability and coarser crystallinity. Several substances such as sugar or tannins are added as dispersants or retardants. Above 110°C silica is needed as phase changes occur above this temperature. Salinity will increase the setting speed. Some of the challenges during the well completions were explained and require careful consideration of setting times.

Generally 70-80% of cements require no form of remediation. In the Gulf of Mexico 5000 wells have annular pressure, indicating some leakage is occurring up the annular interval, out of a total number of wells of up to 100000 (i.e. 5%).
3. MODELLING WELLBORE INTEGRITY.

Mike Celia, Princeton – Models for estimation of large-scale leakage along multiple wells.

In Texas, there are 1-1.5 million wells and in Alberta there are 350,000 wells with 195,000 wells penetrating the Viking Formation alone and 15,000 new wells being added each year. In oil production an injection well may be surrounded by 100s of wells, in gas production there may be 50-100 wells and a few tens of wells in backyard wells. When trying to represent potential leakage we need to consider the problem of upscaling from leakage pathways typically on a millimetre scale to a reservoir or hydrocarbon field or basin. Several types of leakage pathway can be considered depending on the location of the failure point within the well. The consequent high uncertainty in parameters requires efficient computation. The components of the semi-analytical model include injection phase evolution, leakage dynamics, post-injection redistribution and upconing around leaking wells which can lead to flow of fresh CO\textsubscript{2} up a well.

Permeabilities and relative permeabilities were assumed. Fluxes were calculated with flow out radially into intervening aquifers. Leakage in each aquifer varies by many orders of magnitude. In two-phase flow from an injection well to a leaky well, initially only brine leakage is observed. The CO\textsubscript{2} plume can prevent brine upflow when it is thick enough.

A real case history of a field in the Alberta Basin was modelled with an extreme simulation and distribution of leaking wells. The distribution of CO\textsubscript{2} in the overlying aquifers is controlled by the relative permeabilities. The top aquifer accumulated 20\% of the volume injected.

A plea was made for the oil industry to share their experiences of leaky wells with the research community.
4. EXPERIENCE WITH WELLBORES IN CO₂ ENVIRONMENTS

Larry Nugent, BP – Sheep Mountain

The Sheep Mountain Unit (SMU), Colorado produces CO₂ from a naturally occurring CO₂ field, which is transported 408 miles by pipeline for use in EOR floods in West Texas. Recovery from the Dakota (~3400’ TVD, 1036m) and Entrada (3800’, 1158m) sandstones is 1.2 TCF. The produced gas is 96% CO₂ which is currently produced at 54 MMCFPD, across 5 drill sites with 29 producing wells.

The pipeline is constructed from a carbon steel with an operating pressure of 1050-2500 psig, and is gravity fed.

Well schematics were presented and the well completions described. A Class H cement with 2% CaCl and ¼# flocele added, was used for surface casings. Production casings were 7 ⅝” diameter at 3800’ depth. Corrosion issues include tubing leaks involving pin end corrosion and body corrosion as a result of cuts in the protecting coating from the wireline logs. At the wellhead, corrosion has occurred at the master ring joint groove, in gate seal areas and in the tubing head. The tubing in 18 of the 29 wells has been replaced, as well as replacement of seal rings and improved handling of the tubular sections. Wellhead repairs include tubing replacement on 4 wells, 8 master valve replacements and wing valve replacements in 15 wells.

The integrity of the casing is monitored via the casing annulus pressure, annulus fluid levels (diesel), gas analyses and casing hydrotests during workovers. Wellhead inspections involve video cameras and UT readings on the valve bodies.

Lance Brothers, Halliburton – Corrosion resistant cements for carbonic acid environments

The effects of CO₂ on cements is a well-documented phenomena, involving the carbonation of Calcium Silicate Hydrate (CSH) cement matrix and portlandite. The solution therefore is to develop non-portland based cements, such as the calcium phosphate cement (trade name ThermaLock) which contains aluminium hydrates,
calcium phosphate hydrates and mica-like aluminosilicates. In comparative tests with Portland cements, weight loss was 3% compared to up to 50% with Portland cement, depending on the additives used. This cement has been used in geothermal wells with high CO$_2$, CO$_2$ injection wells and sour-gas disposal wells.

**Bill Carey, Los Alamos National Lab. - Character of the Well-Bore Seal at 49-6 in the SACROC Reservoir, West Texas**

The SACROC reservoir is a Pennsylvanian reef, with 3 billion barrels of original oil in place. 1800 wells are located within the 81 square miles, 600 of which are operational. The production zone occurs at 7000’ depth with a field temperature of 50°C. initial pressure was 3200 psi (now 2600 psi). CO$_2$ flooding initiated in 1972 (second CO$_2$ flood in the world), now being supplied from McElmo Dome, of which 62% is left within the reservoir. Drilling and production from above and below the reservoir have been CO$_2$ free. Sidetrack cores have been taken from both injection and production wells to determine the long-term effects of CO$_2$ on casing, cement and shales. Samples have been successfully obtained that allow a profile from the reservoir through the cements and into the well casing, which has been exposed to CO$_2$ as a producer and injector for 17 years. A similar style of alteration was observed to that reproduced in laboratory-based experiments, including the development of orange-stained cement (due to decomposition of AFm phases and precipitation of ferric hydroxide, rather than redox changes) and extensive carbonation, in the form of calcite, aragonite and vaterite. Stable isotope studies were able to differentiate between carbonates in the cement, and altered cements.

These results indicate that EOR sites have tremendous potential for evaluating the feasibility of CO$_2$ storage. Recovery of core at SACROC and from the Tensleep Formation demonstrate that cement can retain integrity for decades. CO$_2$ does attack cement but there are stages of carbonation that precede and help prevent mechanical failure. Experimental studies of the carbonation process are necessary to interpret the observed textures and numerical modeling is helpful in understanding processes and time-scales implied by the observed mineralogy and texture. We should pay just as much attention to the cement/casing that is absent as the core that can be recovered.
One dimensional modeling, using Flowtrans, indicated an increase in porosity in the orange zone from 16% in the cement to 30%, with a dense calcite-rich zone, plus chalcedony and dawsonite (a sodium aluminium carbonate often predicted to form in geochemical models) which probably equates to an amorphous alumina in the altered zone. The lengthscales generated within the models are comparable to those observed in the samples, though the rates of Portlandite reaction were increased to make it react quicker.

5. DESIGNS TO BE STABLE TO CO$_2$.

Glen Benge, ExxonMobil - Meeting the Challenges in Design and Execution of Two High Rate Acid Gas Injection Wells

A case study was presented that provides examples of state of the art design in well completions for acid gas (65% H$_2$S, 35% CO$_2$) injection over a 50-year period in the Labarge area, Wyoming. The wells were 18000’ deep, through a potential mobile salt formation, at a temperature of 300°F (150°C). Corrosion resistant alloys were used throughout. The resistance to chemical degradation of a Portland cement were increased by adding a latex diluent of a specific particle size and adding a non-standard, high alumina cement to reduce the amount of Portland cement. The design plan included a quality control system for the complicated blending, quality checks by multiple laboratories and a plan for future well interventions. A Portland-based cement was chosen for logistical and availability advantages. Complex casing installations were also explained. Following completion, wells were monitored for ultrasonic cement analyser for integrity.

Tor Harald Hanssen, Statoil – Permanent CO$_2$ Storage

The Sleipner operation was reviewed and plans for the Snøhvit field in the Barents Sea introduced. At Snøhvit, the CO$_2$ injection well was drilled in January 2005, 150 km offshore in an environmentally sensitive area where no discharges are allowed. The Tubåen Formation, the target storage reservoir, is a sandstone saline aquifer below the gas field, which will store the CO$_2$ from the produced gas as well as from an onshore power plant. A 13% Cr steel is being used for all tubing.
6. SUMMARY OF BREAKOUT DISCUSSIONS.

The delegates were divided into two groups. The following is a summary of their findings.

What do we know?

The similarities between laboratory experimental studies and observations of cement degradation from wells provides some encouragement, though differences are apparent in the kinetics of reactions. For example at SACROC, some cements have remained intact after 30 years. Some experimental evidence indicate that initial reaction rates are high and then an equilibrium or steady state is achieved.

Important information could be obtained from areas where it was not possible to obtain cement samples from wells (poor cementing or subsequent degradation could be possible explanations) and this should be investigated. CO\textsubscript{2} will dissolve cement in the lab, and is thermally controlled, producing reaction zones which can have different properties and that can slow reaction. The degree of curing does not influence degree of reaction. Two-phase flow is more destructive than single phase (as acidity replenished). Some compositions are resistant to reaction as a result of their chemistry and porous media around cement can slow reaction, though cement is more at risk in sandstone than limestone. There are no industry standard tests for corrosion. Good cementing practices are needed and there are particular challenges for ensuring good cement bonding? in shales.

Need adequate logging on wells (tests of leakage). Flow through the fracture/annulus/boundaries is more degrading than non-fracture flow. Matrix flow is not considered important. Types of leakage include bypass, casing failures and internal shrinkage. An evaluation of EOR wells may provide some useful evidence for long-term reactions although it was recognised that they are not representative of ordinary wells, as the cement is chosen for the harsh environment.

It can be difficult to get a perfect annular cement seal, as the cement bonding is often dependent on the rock type. Knowledge about cement is often anecdotal and based on indirect observations, and can therefore be difficult to capture. It is not known how good early cement jobs were, nor the long-term behaviour of these early cements. 3\% of wells in Alberta leak gas (but may leak through connections,
rather than cement). It was pointed out that injections of slurries, which exceed fracture pressure, fail ~10% of the time, resulting in leakage to surface or aquifers.

Good practice could include some of the following. Integrity is more important in the cap rock than in the formation and some formations are plastic enough to reseal. Cementing the wellbore to the surface or to a mechanical seal may reduce the risk of leakage. Cement flexibility may be important.

Remediation can be difficult.

Identified questions included:

- How can field and lab results be reconciled?
- What is the behaviour of old cements?
- How good are early cement jobs?
- What is the performance of abandoned wells?

*What does this mean?*

It was recognised that current practice is not adequate to ensure long-term wellbore integrity, with no experience for long-term i.e. on the timescale of decades. Standard testing methods are needed and it was suggested that this could be the subject of a follow-up workshop.

Risk and performance assessments should take account of well failure mechanisms including the definition of acceptable leakage rates. We must make the public aware that perfection will not be achievable. This should be supported by a rigorous assessment and monitoring strategy. The challenge in ensuring integrity, is to find leaks, especially low-level leaks, before they can be fixed. Possible techniques include $^{14}\text{C}$, noise logs, focussed cement evaluation (sonic/ultrasonic) tools and temperature logs in injection wells although these are more difficult in production wells due to the warm reservoir fluids.

To avoid poorly abandoned wells we could inject into deeper formations below the penetration depths of wells (though this may induce problems with cement mineralogies) and we could avoid using oil and gas fields and concentrate on saline aquifers.
What should be done?

Education of risks and rewards to both industry and regulators is required with statistical information on leakage being provided from industry on both operational and abandoned wells in current oil and gas production, though some is available from CO₂ fields and studies in CCP. There is a clear need to identify the locations and integrity of all wells that could potentially act as pathways for CO₂ leakage in a storage area. Though less likely to be an issue offshore, in onshore basins such as those in the US, this may not be a trivial issue. The number of wells influences the risk of a leak though this does not mean a high number of wells is automatically a higher risk. It could be expected that a higher number of failures may occur early on in the lifetime of a project, which may reduce over time. However, we do not know what will happen over the long term (100+ years).

This will require the definition of risk-based parameters and techniques to test wells to predict or detect leaks and to identify the initial stress state of all wellbore components. It was recognised that an understanding of the failure mechanisms in wells was currently the focus of considerable effort by industry.

Accelerated testing methods of degradation on several scales, including permeability evolution and leakage at interfaces between wellbore completion materials, are required to assess long-term well performance without making the experimental conditions unrealistic. Useful information on in-situ CO₂/cement reactions could be obtained from samples in wells that have seen CO₂. Redox issues should be considered. Cement Samples from existing wells are needed to improve the dataset from which observations can be made and this may be best achieved during well workovers. However it was recognised that the risks to operators of sampling from operational wells should be minimised.

Research on abandonment should focus on (thermodynamically) stable materials and studies of 3 phase thermal reactions, including biogeochemical reactions.

New potential mechanical liners/barriers should be considered.

To define risks the following need to be established: frequency of failure, mechanisms of failure, the consequences of failure as well as a definition of failure. Delegates, aware that industry has a different set of definitions compared to researchers, suggested the following could be used a criteria to measure well performance:
• No loss to atmosphere
• Acceptable HSE risks
• Deviation from stated objectives – failure to keep injection within target reservoir.
• Define leakage pathways near wellbore as a result of emplacing well. Identify failure modes.
• Migration into potable water zone.
• CO$_2$ reaches above the protective casing.
• Careful consideration of terms like leak and failure are needed.
• Potential for mobilisation of other phases (hydrocarbons, Rn etc.)
• Potential for local shallow accumulation with sudden release thereafter.

An experimental approach to determine field-validated processes was discussed. This was based on a well in an existing CO$_2$ flood or CO$_2$ field, or possibly in an engineered leak. Suggested techniques are listed below:

<table>
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<tr>
<th>Logging techniques</th>
<th>Geochemical</th>
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<tbody>
<tr>
<td>temperatures</td>
<td>Tracers</td>
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<td>Cement bond logs</td>
<td>Fluid sampling</td>
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<th>Well selection criteria</th>
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<tr>
<td>Low risk of failure of experiment</td>
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<td>to operator (choose a well that</td>
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<td>is going to be abandoned anyway)</td>
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<tr>
<th>CO$_2$ in ground a long time</th>
<th>Well with some migration</th>
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<th>Well history/boundary conditions needed</th>
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<tr>
<td>Pressures</td>
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<td>Temperatures</td>
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<td>Initial and current logs</td>
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<td>Geology</td>
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<tr>
<td>Crosswell seismic for CO2 distribution</td>
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<tr>
<td>Permeabilities</td>
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<td>Adjacent activity</td>
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<th>Experimental procedure would be</th>
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<tbody>
<tr>
<td>1. log USIT/MSIP</td>
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<tr>
<td>2. Cased hole RFT (Residual formation t) for fluid samples</td>
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<tr>
<td>3. pressure tracer tests</td>
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</table>
4. Drill oriented sidewall samples in caprock and cements

5. Whipstock samples

6. plug and abandon

**Fluid samples:**
- Full chemical analysis including pH
- Difference between invaded & non-invaded zones
- Biological sampling

**Rock samples:**
- Permeability, porosity
- Saturations
- Porewaters chemical analysis
- Petrographic analysis
- Expose to reservoir brine
- NDT-XRD/ tomography

### 7. FINAL DISCUSSIONS ON THE “1000-YEAR WELL”

A final discussion was held on the issues identified during the meeting that should be addressed.

It may not necessarily be required to demonstrate integrity for 1000 years. A more successful approach may be to prove short-term integrity, for example over 100 years, and then extrapolate to longer timescales.

We must be careful not to present well designs and completions as providing a leak-free solution but rather that industry is constructing the best wells possible. This is the first time that industry has been asked to design wells that must last for such long periods. One way of reducing the risks of a failed well would be to locate the well where a leak would have lower consequences.

There remains considerable uncertainty around remediating previously drilled and abandoned wells.

A research program is required to test the status of existing well bore completions, that would include sampling, testing and monitoring.

An early requirement is to define the failure criteria. Suggestions include loss of CO$_2$ to the atmosphere or to a potable water supply or CO$_2$ leakage to an overlying reservoir.
8. KEY OUTCOMES

- Ensuring well integrity over long timescales has not been attempted before and represents a new challenge to the oil and gas industries.

- It will not be possible to promise a leak-free well, but rather we should emphasise that we can build wells employing state-of-the-art technologies which will reduce risks.

- Portland-based cements will react with CO$_2$, leading to cement degradation. The main reactions involve carbonation of the major cement components – Portlandite and calcium silicate hydrates which are converted to carbonate minerals such as aragonite, calcite and vaterite.

- Degradation results in a loss of density and strength and an increase in porosity.

- Laboratory experiments of these reactions are able to simulate those observed in wells that have been exposed to CO$_2$ in EOR injection and production wells. However, the degree of reaction (i.e. the rate of reaction) may not necessarily be comparable between laboratory and field. This may be due to the need to speed up laboratory experiments, often by increasing temperatures, to reproduce longer timescales.

- One, two and three dimensional models are now being developed to simulate processes observed both in the laboratory and in the field, at the small-scale of specific leakage mechanisms within a well and also over the larger scale examining broad leakage on the basin-scale.

- However, we are unable to use these models in a predictive sense due to a lack of detailed knowledge on specific issues, discussed below in the key research needs.

- New cements have been developed and deployed that reduce the amount of alteration caused by acid attack. These cements either reduce the proportion of Portland-based cement in the mix, add inhibitors or use completely new calcium phosphate-based cements that do not contain any reactive portlandite.
• Studies of well completions from CO₂ EOR operations were recognised as offering significant valuable data on real failure processes and consequences. Although these offer the longest “experiments” to date, timescales are still limited to a few decades.

• Important information could be obtained from areas where it is not possible to obtain cement samples from wells (poor cementing or subsequent degradation could be possible explanations).

9. FUTURE RESEARCH NEEDS

Several broad areas of uncertainty have been identified that define future key research needs:

• The frequency of failure. It was concluded that little data was available from oil and gas operations that enabled frequency estimates to be made. This was due to several reasons including commercial sensitivity and inconsistent definitions of failure. However, some estimates could be made; for example if failure was defined as loss of fluids to the surface, then it was suggested that perhaps 1 in 100000 wells may fail in this way. One possible way to obtain information on frequencies would be to approach regulators.

• The mechanism of failure. Several mechanisms have been suggested during the meeting but little is currently known about detailed processes on the small scale that lead ultimately to leakage.

• The consequences of failure. These could be very different depending on rate of CO₂ loss, total amount lost, location of well (populated, onshore, offshore, agricultural land etc).

10. NEXT STEPS

The IEAGHG will place copies of the presentations and this meeting report on www.co2captureandstorage.info The presentations and report of the workshop will be in a delegate’s only area of the site but a public domain summary report will be produced and placed in the public section of the site.
A follow-up meeting will be held when sufficient progress merits further discussion. Possible topics for discussion could include, *inter alia*:

- Defining well failure.
- Standardising testing procedures.
- Industrial and regulatory evidence for failure frequencies.
- Designing a R&D programme to obtain evidence from existing CO₂ EOR operations.
- Designing monitoring procedures.
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