WELLBORE INTEGRITY NETWORK MEETING

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INTERNATIONAL ENERGY AGENCY

DISCLAIMER AND ACKNOWLEDGEMENTS

IEAGHG supports and operates a number of international research networks. This report presents the results of a workshop held by one of these international research networks. The report was prepared by IEAGHG as a record of the events of that workshop.

The 6th international research network on Wellbore Integrity was organised by IEAGHG in co-operation with Shell. The organisers acknowledge the financial support provided by Shell for this meeting and the hospitality provided by the hosts at the Palace Hotel, Noordwijk.

A steering committee has been formed to guide the direction of this network. The steering committee members for this network are:

Bill Carey, LANL (Chairman)
Toby Aiken, IEAGHG
Martin Jagger, Shell
Stefan Bachu, Alberta Innovates – Technology Futures
Theresa Watson, T. L. Watson & Associates
Mike Celia, Princeton University
Walter Crow, BP
Rick Chalaturnyk, University of Alberta
Neil Wildgust, IEAGHG
Millie Basava-Reddi, IEAGHG

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SIXTH WORKSHOP OF THE INTERNATIONAL RESEARCH NETWORK ON WELLBORE INTEGRITY

Executive Summary

The IEAGHG Wellbore Integrity Network is now in its sixth year of existence, and the sixth meeting was held in Noordwijk Ann See, The Netherlands in 2010. The attendance for the meeting included a mix from industry, academia, research and regulators, with a total attendance of 59 delegates, spanning 8 countries.

This eclectic mix of representation ensured the discussion sessions remained varied, without bias, and included debate reflecting different viewpoints. The future of the network will be determined over the next couple of years, with a proposal to hold a combined Modelling / Wellbore Integrity Meeting in 2011, and the 2nd Joint Network Meeting in 2012. The outcomes of these meetings will help to shape the future development of the IEAGHG networks as a whole.

The format of the meeting allowed for 20 minute presentations with 5 minutes for questions. Each of the three meeting sessions was followed by prolonged discussion sessions where ideas and experiences were discussed by the meeting attendees at a greater level of detail. These discussion sessions are the primary focus of this report, and the presentations are available on the network webpage for reference.

The presentations and discussions included some novel concepts, not previously discussed at this network, such as the ability of micro-annuli to self heal, and relying on shale encroachment as a secondary sealing mechanism. Of particular interest and providing a possible outlet for network developments was the presentation of the recently launched DNV JIP on CO_2 Wells.

Presentations covered 3 areas; regulation and classification guidelines, experimental developments, and projects and practical experiences. The facilitated discussions followed each session, and generated insightful debate amongst participants.

Again, the level of involvement of the attendees that continues in these meetings demonstrates the continued relevance of wellbore integrity as a topic for investigation, and the inclusion of topics not previously discussed, as well as further developments and assessments of regular topics indicates that this network remains a worthy element of the IEAGHG network programme.

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Introduction

Welcome by Shell, Davie Stewart, Vice President, Wells, Shell

After an initial welcome by Toby Aiken in which the delegates were welcomed to the meeting, Davie Stewart gave a welcome on behalf of the hosts and sponsors, Shell, and explained Shells' activities relating to both wellbore integrity and safety.

Wells and the associated safety concerns are prominent throughout Shell's business activities, and the 'Goal Zero' concept is targeted at incident free operations. The global expenditure on wells and drilling activities is expected to rise greatly in the coming years, and is predicted to show an increase of 33% over the next four year period to 2014.

Shell has instigated a rigorous scheme to minimise accidents and ensure the prioritisation of the safety of its workers, and this scheme extends from standard compliance with health and safety requirements through to all field-based and drilling activities; hence the impact on wellbore integrity. Dave Stewart framed the well integrity issue in the context of the then very recent BP oil spill in the Gulf of Mexico.

Shell is developing innovative drilling technologies and techniques, such as the 'mono-diameter' drilling operations that have proved successful when deployed in an onshore environment, and is now being taken to offshore scenarios as well. The key elements of wellbore integrity cover design, technical and operational integrity aspects, and each of these elements incorporate compliance elements and cross-over's with each area, and it is important that the elements of these areas allow for safe future abandonment, which is where the CCS activities have influence on the policies.

Shells' well integrity management model illustrates how maintenance and tracking databases play a role with design and implementation. Shell now has extensive data on around 17,000 wells, which provides a good database of information for them to work from to ensure safer design of future wells. To maintain staff competency, Shell runs an internal learning package, which all staff have to pass in order to work in the well discipline. As an associated activity, Shell is developing a well abandonment manual and guidelines, which includes long term abandonment integrity for CCS; this is a work in progress and is still under development.

Bill Carey asked how much Shell focus on risk management in wells, and Davie Stewart confirmed that it is integral within Shell, and well control is seen as the number- one risk that needs to be managed. Recent international events including the BP oil spill have demonstrated that this is key in ensuring worker safety among other things, and the second element that needs careful management is the scaling up of activities. This is approaching, and the challenge for Shell and other operators will be to provide the products necessary to meet the increasing demands, and this will incorporate additional risks that will need to be managed.

Mike Celia highlighted the issues in North America; that old abandoned wells are seen as a high risk for CCS and what is Shell's stance on this? Davie accepted that this will be a problem, and used the analogue of moving their operations into China to provide power for the Olympics in Beijing. Shell inherited 18 wells from other operators, and after following a process of careful examination to determine the state of these wells, they were than able to make informed decisions over their future. Mike replied that the 6 million wells in existence in North America represent a risk of leakage, even when they are not being used in CCS operations, and Davie accepted that long term integrity elements are a vital question for the future, and that in order to meet this challenge, there is a need for the subsurface specialists to liaise with the CCS teams.

Neil Wildgust asked how big a conflict would be caused by the competing interests of CCS schemes with any upscale of oil production operations, and Davie accepted that this will be a case for careful planning, with resources prioritisation. Hopefully both sides of the business can be accommodated, but it is possible that there could be a conflict.

Session 1: Regulation and Classification Guidelines

1.1 Introduction to Session,

Bill Carey thanked Davie for his talk, and reiterated that the focus on safety is a large concern for the future, both within the industry itself and also for public perception.

Bill outlined the agenda for the next 2 days, and explained the issues that we face now and for the future. He briefly described the discussions within the steering committee in planning this meeting and the agreement that methods of determining and demonstrating long-term zonal isolation should be a key issue for discussion.

1.2 TNO Study, Well Abandonment Review: Muriel van der Kuip, TNO

This presentation provided an update to the network of a presentation given last year, focussing on an IEAGHG report that was presented in a draft format, but following the expert review and comments from the network was subject to considerable changes and amendments.

One of the study focus areas was differing regulations and practices with regard to cement plug requirements including length and coverage. The factors identified that have allowed improvements of well abandonment techniques include developments in procedural capabilities, development of improved materials, and to a limited extent the impact of prevailing regulations.

Conclusions of the study were highlighted to demonstrate that we have the knowledge and understanding to utilise best practice for abandonment of future wells, and we can ensure that the economics are matched to practicalities of abandonment. The main focus for further work will be on historically abandoned wells, and the possibility of a lack of extensive data on such wells.

Paul Hopmans asked about the mechanics of self-healing of wells, and Muriel referred Paul to the report detail which addresses this topic.

Bill Carey asked if there were significant differences in measures applied in corrosive environments according to the questionnaire results, and Muriel confirmed that the responses received didn't yet consider the corrosive environment, but were looking to address the situation in the future. Muriel also suggested that the study results identified geomechanical issues as more significant for well integrity than geochemical degradation.

1.3 ERCB Injector Well Classification: Fran Hein, ERCB

Fran Hein explained the development of the ERCB well classification system, and highlighted that it was still under review. She explained the role of the ERCB and explained the concerns being addressed regarding CO_2 injection practices. There are documented cases where contamination and communication between heavy metals and groundwater are being looked at for key findings, and the identification of mitigation and avoidance measures. These cases in Alberta are not directly related to wellbore issues, but relate mainly to temperature processes in in-situ bitumen thermal projects, where at the horizontal in situ well bores natural arsenic is liberated from the subsurface formations and remobilized and transported to surface. This would be a similar concern in CO2 injection sites, where there may not be thermal effects but there may be mobilization of heavy metals, and planned mitigation concerning such mobilization and potential cross-well flow will have to be considered in planning CO2 injection schemes.

In the period of 2005-10, well numbers in Alberta increased from 321,497 to 410,027, representing an increase of a third in five years; hence ERCB is dealing with a large number of wells, potential abandonments and second-life applications. The ERCB are employing a wide range of techniques to determine the current state of wellbores, and this varies depending on the purpose of the well both historically and in the future. It was explained that the issues that are unknown can prove to be vital, and examples of this would be the placement and type of cement used in old wells, but data has been lost or not recorded. Currently, Class III wells cover CO_2 H_2S and hydrocarbons or other gasses and the current review will strip out CO_2 and H_2S into a separate classification.

Ron Sweatman questioned the non-allowance of remedial cementation that was shown on the slides, and Fran explained that the plan was that the cement should be done at time of installation, rather than remedial cementing being part of a plan, but if it was necessary, it would be allowed.

Matteo Loizzo asked if there was data on the reliability of monitoring techniques; how big would a leak have to be to be detected, but Fran explained that this was not her speciality and questions should be directed to Theresa.

Michael de Vos asked what type of intervention would take place to enforce the directives, and Fran explained that the company would have to go through a long application process, and this would cover compliance (depending on operation type) and this would be repeatedly reviewed, and the enforcement action could include an injection well being shut-in until remediation has taken place, and it was confirmed that this regulatory capability has been exercised in the past.

Regarding injection into carbonate reservoirs, Fran confirmed that the example of the Ireton shale was a cap rock for a carbonate reservoir; and there are a number of website postings that show characteristics of caprocks in the subsurface. These postings are on the public portion of the ERCB website, and are found in the annual in-situ oil sands performance presentations to the Board.

Paul Hopmans asked how the industry was receiving the regulations, as it represents a large move from previous requirements, to what is needed now. Fran explained that conventional oil and gas activity is declining in Alberta, so the conflict is reduced, and as the regulation is still in the planning stages, there is no evidence to suggest how industry will react and adapt to the new regulations.

Bill Carey said the US has known problems with shale gas and fracturing operations, causing controversy; and asked Fran about her thoughts on shale gas activities and what they can teach us about CCS? Fran confirmed that there are definite analogues as far as caprock issues go, but time will tell is the current strategies are correct.

Ron Sweatman suggests that there are similarities of the API work, and the information could be shared to mutually help each other.

1.4 DNV JIP, Early Status and Potential Input from WBI Network, Mike Carpenter, DNV

This presentation described a newly launched JIP lead by DNV that will develop a guideline for managing the risks associated with active and abandoned wells at CO_2 storage sites. It is one of around 30-40 JIP's that DNV launch each year covering a wide variety of topics. The aim of the guideline is to demonstrate the current state of best practice in the industry and thereby support regulatory, and ultimately political, decisions to implement CCS.

DNV recognise that major concerns exist around CO_2 storage site safety and long-term integrity and believe that well integrity issues are a major factor that need to be addressed in this context before CCS can be accepted into major funding mechanisms, such as the CDM.

The guideline to be developed by the JIP will cover i) the risk assessment of active and abandoned wells, and ii) the re-qualification of existing active wells for use as CO_2 injectors. A draft version of the guideline will be tested out in a number of real case studies later in 2010 in cooperation with industry. The final guideline will be published in the first quarter of 2011.

Paul Hopmans questioned the apparent focus on the design stage rather than the operational monitoring phase of CCS, and Mike confirmed this is correct, and that the primary focus will be on the initial selection of sites and the engineering concept selection. Paul suggested that a potential gap could be the durability of the process – how can it be continued from initial phases through to post completion.

Mike Celia asked about the abandoned well aspects, and how this would encompass work already done, for example Watson and Bachu's extensive research. Mike Carpenter explained that this would be a relatively high level aspect, using a simple methodology rather than an in-depth assessment. It will use a similar scoring mechanism that Watson and Bachu used, with a risk assessment matrix to determine overall risk level. If the site is selected for development, then a further assessment will be used.

Following questions from other delegates, Mike confirmed that the JIP is a qualitative approach and should be seen as a starting point for further work rather than the definitive report.

1.5 Discussion Session 1: Impact of Regulations and Potential Network Input to JIP

Bill started the discussion by asking how important blow outs from abandoned wells will be – we often talk of chronic leakage, but an acute leakage of a blowout would be very bad news. How does the group feel about this?

Mike Celia refers to the Crystal Geyser images popularly used showing children playing in it, and that maybe it should not be as much of a concern as it is, but points of view will differ depending on level of knowledge. CO_2 is not that dangerous a substance, comparatively speaking – it doesn't pose great risks to safety, but the public perception would be damaged following a leak or blow out event. Mike Parker commented that evaluations have been carried out looking at true CO_2 well blowouts and the risk is more operational, the human risk is actually very small, but the operational challenge of getting them back under control is much more difficult, and this has been experienced in industry. A CO_2 related blow out is extremely rare, but naturally the focus tends to be on the dramatic events. Mike Celia cautioned that the scales are going to change; the small scale we have now may cause low risk blowouts very rarely, but the necessary scale up we are looking at for full deployment may necessitate us to rethink this. Ron Sweatman quoted a 0.008% incidence of blowouts per year, and this statistical data suggests that orders of magnitude differences cannot be assumed in scaled up operations. Mike Celia said that with EOR operations, the fluid in and fluid out will be approximately equal, so pressure changes don't come into it, but with CCS operations there will be a pressure change, so comparability of the situations is not necessarily true. Ron clarified that pressure is always elevated in EOR operations, so there could be some comparability of the data.

Bill Carey pointed out that most blowouts occur when drilling into high pressure gas fields and most CCS operations will be drilling into unpressured or lower pressured reservoirs, so blowouts maybe less of an issue. Another topic for discussion is how to represent risk, a binary approach of '1 in xx wells will fail' is one approach, but the alternative is to look at the range of wellbore permeability in well distributions, and state that some wells will always leak more than others, so the scale element is more of an issue. How should we think of risk?

Paul Hopmans suggested that the risks associated with hydrocarbon wells is understood as the risks have been assessed by the production company, but the issue is more likely to involve when the money is coming from public purses and might eventually determine that CCS can't operate in a given locale. Neil Wildgust suggested that the public and or regulators will simply look at environmental and human health concerns rather than financial risk, and as a network we should be looking at what confidence level we have of the avoidance of leakage as this will be the focus by regulators and the public.

Bill Carey commented that a previous IEAGHG study looked at the experiences of the natural gas industry and the approach used was very incident related, saying leak rates are of '1 in xx', rather than looking at distribution curves. Fran Hein commented as a regulator that other concerns other than environmental and human safety, are transference between areas in the subsurface – what happens if groundwater is contaminated – who is responsible – the operator or the regulator for allowing it?

Mike Parker suggested that a blow out is a dramatic but rare event, a much more common event is a mechanical integrity failure of a well, a low grade leak of gas from one area to another is a more frequent event, and technically is a blow out, but the term blow out is more usually associated with the dramatic geyser like event. Risks are manageable even when they are high, and we know how to manage these risks from the oil and gas experience. This knowledge and experience can be directly transferred to CCS operations. Standard industry practice includes the ability to re-plug wells, the challenge is actually in finding these wells – wells drilled in the 1920's to the 1940's often have sparse data. It's a treasure hunt to find the data, and this can cause as many problems as anything else. There are instances of wells being searched for using metal detectors. Once found, the next question is what is in the well – how was it abandoned? Some wells have been found abandoned with tree stumps inserted in them.

Mike Celia allowed that these were all fair points, but the sheer scale of CO_2 injection would necessitate such an area of influence, that it could evolve more complexity with the area moving outside of the target field. Mike Parker said that although the scale is larger, the process is the same, and Paul commented that the risks are the same, regardless, and the same issues need to be addressed in each situation.

Mike Carpenter suggested that although we know the processes work, but how do we gain support for these activities: public bodies often refute the evidence so politicians don't which story to believe.

Sarah Gasda suggested that the incentive for reworking wells for production basis is present, but when it comes to CCS, the financial incentive will not be there to go out and interrogate such a large area of wells, and operators won't have the finances to rework wells based on possible, unproven risk. Operators will need a risk map to determine which wells need to reworked and which can be left and monitored. Ron Sweatman said there are technologies available that can monitor and predict pressure propagation up to 30km away, and the only reason it isn't used is that it hasn't been necessary in EOR yet as mass balance techniques can be used to self-monitor sites.

Neil concluded that so many talks show such variations on impact factors and range of effects, that there needs to be clarity on specific scenarios – if a field has a lot of penetrations without knowledge does that stop the site dead before further action is taken? What effect can the presence of penetrating wellbores have?

Session 2: Experimental Developments / Discussions

2.1 Evolution of Cement Mechanical Properties, Daniel Quesada, Schlumberger

This talk focussed on the known and well documented changes that occur when cement is exposed to CO_2, and focussed on the mechanical effects and the likelihood of whether the effects were likely to decrease wellbore integrity, or whether CO_2 could mechanically enhance the properties of the cement to aid wellbore integrity.

Results demonstrate that the carbonation front itself shows some variance in compressive strengths with a tendency to be a zone of weakness, whereas the carbonated zone has a higher compressive strength than the un-degraded zone in the core centre. The issue of this is that the weakened zone around the front can be the focus for the formation of new micro-annuli. Whether this is correct depends on the carbonation scenario and more detail on these scenarios can be found in the presentation slides.

Daniel was questioned regarding the properties of the carbonated cement, and the source of the values. It was confirmed that the data came from experiments performed internally within Schlumberger at 90^{o}C, 49^{o}C and ambient temperature of about 19^{o}C.

Asked whether estimates of failure implicates on the hydraulic properties, Daniel was uncertain, and will attempt to provide an update after the meeting.

2.2 Experimental Wellbore Corrosion Work, Bill Carey, LANL

Bill presented some ongoing work on corrosion of materials in the wellbore. He explained that a sample that had been taken of wellbore casing from Brazil corroded rapidly while in transit from Brazil to the Los Alamos labs, and by the time the sample was examined for experimentation purposes, the corrosion was extensive. This demonstrates the potential speed of corrosion processes.

Bill's experimental work considered corrosion rates of steel in the presence of Portland cement with a focus on the effect of an interface gap (microannulus) on corrosion rate. Experiments show that if the cement remains unaltered and highly alkaline, then it will protect the steel casing against corrosion. At the point where it stops being alkaline, it will no longer act as a protective compound, and the presence of CO_2 will carbonate the cement and change it from alkaline to non-alkaline, leading to corrosion of the steel. It was demonstrated that interface gap size greater than 100 μm has an effect of 2 orders of magnitude on the corrosion rate shown in mm/yr on a log/linear scale.

Ron Sweatman asked if future work would consider commonly used techniques to minimise or prevent steel corrosion, and Bill explained that the focus of this work is on old wells that aren't protected, so the use of new materials is less relevant in this situation. It is possible that in the situation of an old well being converted for reuse, some of these new technologies could be retrofitted to bypass the issues.

Bruno Huet asked where the iron goes in the reaction, and Bill explained that the iron carbonate can fill the interface. The presence of the interface in the first place leads to the deposition of iron, so in this case, the iron could correct the problem; more likely is that the iron gets washed away into the reservoir, but it is possible that iron carbonate could seal the micro-annulus and therefore prevent further corrosion. This was evidenced in the experiments, even at high rates of flux, so this confirms that it is possible.

The experiment is very dependent on the oxygen concentration, and in these situations, the system is purged by nitrogen, so it is unlikely that there is an element of oxygen-induced corrosion in this experiment. In real life scenarios, this may not be possible so this needs further investigation.

Ron Sweatman commented that at the depths associate with the phase-change, there is tremendous up-scaling necessary to seal the micro-annulus.

Daniel Quesada questioned in which situation would brine and CO_2 be flowing together in a microannulus, and Bill confirmed that when hydrostatic pressure is involved, the drive could cause the two substances to flow together. However, he acknowledged that the microannulus properties could be such that CO_2 causes drainage of brine resulting in a microannulus mostly filled with CO_2.

Matteo pointed out that there will be a lot of water coming out of the cement, so the micro-annuli will not be notably dry, suggesting that the brine will always be present in some concentration.

2.3 Stability of Leakage Pathways along a Cement Annulus, Laure Deremble, Schlumberger

Laure's presentation used computational methods to assess the evolution of leakage pathways caused by defects in the cement. The study examined the role of calcite precipitation in the defect space and whether this affects the leakage pathway. If the precipitation reaches a sufficient thickness of deposition, it could theoretically block the defect, thereby removing the leakage pathway. Scenarios with a higher concentration or flux of CO_2 are shown not to seal the defect, whereas lower concentrations will. There was a high sensitivity of the results to the initial defect width and the pressure drive for the CO_2.

Bill asked for clarification of the assumptions for the leaching of calcium and Laure explained that a mass balance process was used to determine the flux of all elements, as a function of the external concentration. The assumption was that the limiting factor was diffusion.

Ron asked if future work will look at different cement formulations and different flux chemistry. Laure explained that this would be looked at but the more complex the cement formulation, the more complex the reactions.

2.4 Experiments on Cement Carbonation in a Brine Reservoir: Controversy or Consistency? Bruno Huet, Schlumberger

Bruno's study used numerical modelling to compare experimental studies of cement carbonation under varying conditions and the variance in results that have been obtained regarding cement carbonation. The aim of the study was to assess the differences in laboratory results compared with field results. The overarching objective is to finally answer whether the extensive experimental results obtained to date show consistency or whether we need to formulate new experiments to further determine the effects.

The first questioner asked whether the analysis can account for the differences occasioned by the variations in the cement curing conditions? Bruno explained that the initial curing conditions are known, and we can predict to a certain extent the transport properties. Another question regarded the source of the calcium in the calcium carbonate, and Bruno explained that the source was the cement itself.

Transport properties were changed by the experiment, and this has to be allowed for to reproduce the results of the original experiments. The other properties can be adjusted to match the transport properties, and this does introduce an uncertainty to the procedure, but it is within acceptable limits for the experiment.

2.5 Cement Performance, Andreas Brandl, BJ Services

This presentation addressed the difficulties encountered when dealing with projects with high temperatures and high pressures (HTHP). Experiments on cement carbonation were conducted on cement systems with fly ash, and with silica flour, both of which were initially free of portlandite. Samples were cured 96 hrs at 3000 psi and 300 F and exposed to CO_2 at 3000 psi and 300F for up to 6 months. Comparisons were made between 1 month and 6 month exposure.

The case study demonstrates that paying attention to the conditions and designing the installation accordingly allows good cement bonding and effective zonal isolation even in the difficult HTHP environment. Experimental cement samples in HTHP showed the impact of adding Pozzalan elements to the cement, demonstrating greatly reduced carbonation after both short and longer periods.

Andrew Duguid asked whether calcium hydroxide phases were considered, and the extent to which they existed? Andreas confirmed that they were considered within the procedure, and the slides demonstrate that no further Portlandite was detected. Bill Carey asked if the experiment looked at plain Portland cement as the image of the ‘conventional’ cement showed some silica flour present. Andreas confirmed that silica flour was added as it was considered to be the industry standard.

The flaking that was observed could be a relic of the depressurisation effects if the depressurisation process was too rapid, and Matteo Loizzo asked if this was possibly a reason. Andreas confirmed that the depressurisation was at a suitable rate to avoid this being a factor.

Ron Sweatman commented that the experimental conditions were not necessarily representative, and the issues that were investigated were identified and addressed in previous research.

2.6 Mechanical Integrity of Cement, Emilia Liteanu, Shell

Emilia described experimental research on the mechanical failure behaviour of wellbore cements at reservoir conditions such as those at the De Lier field in The Netherlands. Tri-axial methods were used and key parameters investigated included pore pressure and confining pressure. At higher confining pressures, cement samples failed ductilely and showed strain hardening. At lower confining pressures, cements failed brittlely. The experimental results demonstrated the effects of carbonation and showed some degree of self-healing of induced fractures. The permeability of samples without fractures decreased with time of exposure to CO_2.

Questions were asked regarding certain elements of the experimental procedure which have the potential to alter the physics of the reactions. This was accepted, but all reasonable steps were taken to minimise the effects and an incident while transporting one sample demonstrated that the fractures had healed as the sample did not split when accidentally dropped. Ron Sweatman confirmed that Halliburton has completed similar experiments with similar results, but some of the cement formulations demonstrated significantly swifter healing reactions. Emilia explained that the instrumentation required for this was not available, and this is why the experiment didn’t address this.

Matteo Loizzo questioned the method in which pressures were applied, as the inducement of pressure has the potential to affect the sealing potential, and the pressures can induce the CO_2 to pass through the existing fracture rather than finding a pathway without external input; this doesn't necessarily affect the results, but an alteration to the method could generate more reliable results.

Laure Deremble suggested that the pressure could induce healing without the presence of CO_2, and Emilia accepted that this is possible, but restrictions prevented this being incorporated into the experiment to determine the viability of this theory.

2.7 Discussion Session 2: Are we confident of new wells; should we focus on work-over of old wells?

Matteo Loizzo started the discussion session, stating that new wells will fail, and the failures will be similar in nature to the failures of older wells. Therefore it can be deduced that if an old well has 'good' cement, it will fail in the same way as new wells. The main wellbore integrity issue comes from bad abandonment procedures in the past; the practice is the key element, and new wells may not stand up to usage even using good materials. It should also be noted that not all wells will fail. Paul Hopmans responded that in new installations, the pressure test process, intended to ensure the integrity, has the potential to create micro-annuli. Matteo accepted this, but suggested that as soon as CO_2 is injected, micro-annuli will form, and this is an unavoidable element.

Old wells will inevitably cause more issues, for example if storage is attempted in depleted gas fields, the wells are in a depressurised reservoir, and are therefore likely to have been subjected to mechanical stresses. Paul Hopmans countered that although this is true; there are simple methods to allow for this and to mitigate the stresses. Stripping of old infrastructure and installation of mono-core wells is a near-perfect situation, but this will of course be expensive. The same process could be applied to new wells just as easily.

The possibility of adding some clay material to new abandonments can act as a safeguard on top of existing cement. Paul confirmed that Shell is investigating this at the moment, but no papers have been written yet. The issue associated with clay is that clay is not a living element such as cement, and we don't know how it will react and behave. The counter-argument to this is that if we are happy with clay as a caprock, we should be happy with it as a well completion material. Clay is used in water shut off wells, and this works very well. Matteo explained that this is done in many situations, but the issue is that it prevents further injection or reuse as clay cannot be altered after insertion. Paul explained that this has been tried, but the issue relates to exact placement and the maintenance of a seal, which is very difficult in this situation. It is an untested method, and cannot be relied upon on its own due to unpredictable swelling effects.

Suggestions were made that the decisions between old and new wells ultimately come down to costs, but Paul stated that as new depleted reservoirs will not be discovered, old wells must be addressed. Historically, wells have not been abandoned to consistently good standards, so when old wells are encountered (if they can be reliably located) they are likely to be full of surprises. CO_2 storage will ultimately be instigated in populated areas as that tends to be where power stations are.

Matteo Loizzo referred to an industrial based presentation at the last meeting where he stated that with respect to EOR operations, every well will need to be recompleted, and this lesson had been learned through experience. The implications on costs of this fact are inherent, and planning plays a part here; if you plan in advance to recomplete, the cost is deemed acceptable, if it isn't planned for, it will prove expensive.

There are countless examples of issues when encountering old wells, and this may indicate that old wells are likely to be the route of the majority of issues. Old wells may be adequately abandoned, but very old wells are likely to be more problematic. Over the last 20 years, more attention has been given to cementing practices, centralisation of casing and pressure testing, so oilfield practices have improved, and we could possibly therefore look at wells from the past 20 years being suitable for storage, there would be some unsuitable, but the locations of these wells is known and can be anticipated. Mike Parker concurred with this, but put the cut-off at around the early 1970’s. In an old field, you must look at every wellbore individually. An operator may have good quality data on a very old well, but just as likely will not; also the quality of the data must be analysed and validated. A decision must be made as to what level of confidence is acceptable. Andrew Duguid suggested the opposite; that data from the 1920’s can be excellent, and if the data is present, then it will be extensive, but some newer wells are found to be patchy in terms of data quality. The issues will be compounded when moving into third world countries and the data will be less reliable - if present at all. Issues will also arise when taking over assets from previous owners. Wells that should be abandoned are often only ‘suspended’ and require further work and expense.

Another issue for consideration here is the extent to which depleted oil and gas fields will be utilised – saline formations form the greater percentage of storage capacity estimates, and these are much less likely to be subject to issues of old wells.

Matteo questioned the use of the term ‘depleted reservoir’ as no reservoirs are actually fully depleted in normal operation, and as demand rises, extraction can become economical again, so no oil company will hand over a field before it has been effectively depleted, and this will take a long time. It was pointed out that there are a series of oil fields in the North Sea that are very close to close of production (COP) and they are well placed between Holland and UK, and have infrastructure in place. They could be used for storage in the depleted fields, if the storage community and operators are prepared; depleted fields still offer a good option for storage due to the knowledge and data available, hence we should still consider depleted fields as an early opportunity.

Session 3: Projects & Practical Experiences

3.1 Grooved Horizontals for Extended Reach Injectors, Inge Carlsen, SINTEF

This talk described an innovative approach to drilling of injection wells where a rifled groove is incorporated into the design of the well resulting in a reduction in friction and an improvement to the range of the injector well.

The flexible nature of such wells may enable an injection well to be drilled along a path which allows access to a storage area without compromising the integrity of the caprock. The manner in which the wells are drilled facilitates simpler and more streamlined installation of wellbore elements and materials.

Bill Carey asked how the drilling tool ensures centralisation, and Inge explained that the tool includes side cutters which can be utilised to ensure accurate placement and centralisation of the wellbore.

Laure asked how the cementing took place as the wellbore is not a constant width, but Inge explained that they feel the cementing process will prove to be easily achieved, although there may be a requirement for an increase in the quantity of cement.

3.2 Managing Wellbore Integrity of Large Wells, Paul Hopmans, Shell

Paul Hopmans presented the management system for Shell's large number of wells, demonstrating the methods of data representation and storage. Using Shell's database system, information is captured detailing the abandonment or current status of all wells under Shell ownership, and this database can be interrogated by location around the world.

Paul went on to explain Shells approach to risk management with regard to wellbores, with specific regard to offshore wells and the risk of casing failure or casing collapse. Paul noted that a substantial number of wells from the database have had communication problems such as sustained casing pressure (SCP). He highlighted that flow on the exterior of the well carries a particular risk with respect to corrosion of steel. There are no currently accepted or practiced procedures for well abandonment that specifically address CO_2 sequestration. The presentation concluded with an overview of the challenges for wellbore integrity directly from CO_2 storage operations.

Inge asked about the experience of the handover of wells, and Paul explained that the processes for handover vary from company to company and can be either explicit or vague, depending on the company source.

Fran asked if there was any indication of the region of influence in Abu Dhabi, but Paul explained that there are two different operating companies present there, so it is not as simple to determine the differences between these, but this was allowed for in the checks that were made in the handover process.

Mike Celia commented that there are varying messages coming from different sources, and there is a great variance in the language used to describe "leakage", "blowouts", etc. Some comments suggest that problems are very rare, with incidence rates being very low, whereas the presentations from Shell amongst others suggests that the problems are more common; this inconsistency needs to be clarified before the conclusion is passed to regulators and the general public to avoid inconsistencies in messages. Paul distinguished between problems of mechanical integrity which reflect communication between zones within the well and "loss of well control" which means flow to the surface.

Mike Parker clarified the distinction between failures and small leaks and the loss of well control. The fact that a well may lose well integrity does not mean that the well is out of control, and these situations are fixable. We need to distinguish between fixable issues and issues where the operators lose control of the well. The message from industry that they can fix wells all the time is going to give us the information that we need in order to be able to survey the issues of the wells we cannot access that are likely to cause issues.

3.3 DOE Funded Wellbore Survey Investigations, Andrew Duguid, Schlumberger

Andrew described a new wellbore survey currently being instigated on behalf of the US DOE. The focus is on wells that have not seen CO_2 and were not designed with CO_2 in mind. The wells that have been in the ground for anything over 20 years up to 100 years or more are likely to cause the majority of problems, and therefore the survey will focus on these wells. The presentation illustrated the wells chosen for the survey, and the schedule of testing.

Various questions were asked regarding the specifics of the results obtained to date, and these were explained by Andrew. One question asked what level of uncertainty was involved with the thickness measurements using logs at various points within the well, and it was stated that the uncertainty was in the order of half a millimetre.

3.4 CO_2 Injector Remediation, API CCS Taskforce, Mike Parker, Exxon Mobil, and Ron Sweatman, Halliburton

Mike and Ron outlined the activities of the API CCS Taskforce and the work on class 2 UIC wells. There are approximately 15,000 CO_2-EOR wells in operation in the US, and it has been shown that a loss of control event is estimated to be of a frequency rate of 0.0087% of wells per year. This is referring to a total loss, rather than wells that have some minor to moderate remedial needs at some point.

The activities involved airborne magnetometer surveys to determine the location of old and unrecorded wells. The area being worked by Anadarko includes a small town that was wary about CO_2 injection under their town, so water injection wells are being used around the town border to act as a barrier and to control plume migration to ensure the area below the town is not encroached by the CO_2 plume.

Conclusions of the activities show that the oil and gas industry does have a lot of knowledge that can help CCS in terms of technologies, the scales involved with injection programmes and also with regard to maintaining isolation integrity.

Mike Celia questioned the images showing cement problems behind the casing, and asked how frequent the issues would be where the operator would need to go into a well and take remedial action. It was explained that this would vary greatly, but the key message is that no well is likely to have such a good cement job to mirror the schematic diagrams, but the technologies are always improving.

The instances of loss of well control due to CO_2 and CO_2 related blowouts are a relatively uncommon event. At the GHGT9 conference, a presentation by Ian Duncan showed examples of around 8 or 9 of these events.

3.5 Risk of Leakage through Wellbores; is it really that high? Matteo Loizzo, Schlumberger

Matteo Loizzo described the case for using various analogues for CO_2 leakage through wellbores and asked whether the risks were as high as advertised, or whether the general view was more of a worst-case scenario. The presentation includes the analogues of underground gas storage and steam injection and the number of events of major and catastrophic events relating to these operations. The assessment concludes that the approach taken should focus less on assessing whether or not leaks occur, and focus more highly on whether damage occurs.

Paul Hopmans asked if all the assumptions were on the basis of pure CO_2, and Matteo confirmed that this was the case, and leaks of other gases and substances would behave in similar fashions, with similar effects as the thresholds for safety are similar.

Referring to the ‘no leak / no damage’ concept, questions were asked regarding the feasibility of such a view. Matteo suggested that this is a personal view, but a much more pragmatic view which should be considered to facilitate deployment.

3.6 Sustained Casing Pressure, Analysis as an Analogue for CO_2 Leakage along a Wellbore: Case Study, Results and Limitations, Nick Huerta, University of Texas

This presentation focused on sustained casing pressure as an analogue for learning and predicting CO_2 leakage, using a specific case study, and examining the limitations of this process. Again, this demonstrated that modelling of pressure build up can provide the necessary details and parameters for the accurate modelling and prediction of CO_2 leakage. The future work identified in this study is to develop a wellbore leakage model specifically relating to CO_2 situations.

Sarah Gasda asked if other parameters, other than permeability, were measured, and Nick explained that if the data was assumed to be of a suitable quality, then the data would be used, but this was not always the case, and the work is ongoing.

3.7 Identification and Qualification of Shale Annular Barriers, Stephen Williams, Statoil (via audio link)

Describing the philosophies of the Statoil operations, this presentation looked at the use of double barriers amongst other aspects of P&A (plug and abandon) processes. The double barrier is a requirement by law in the Norwegian theatre of operations, but the secondary barrier is often found to be missing, or inadequate, requiring the additional installation of a second barrier. There are various options available for this, however they are all destructive, time consuming and prone to failures. During operations, however, shale swelling and collapsing has been observed against uncemented casing, and it is suggested that this could be used to good effect, effectively using the collapsed formation as the secondary barrier. Tests have been developed to detect the fracture strength of formations, and the pressure can be plotted against strength to demonstrate whether the formation would make a sufficiently impermeable, strong barrier.

Frank van Dam asked about the practicality point of view, of how the shale is being made to ‘go off’ but Stephen explained that the shale creep is a natural process, and is not induced in any way. This is the theory, and further tests should confirm this.

Bill Carey asked how this might apply to long-term wellbore integrity if we have cemented regions surrounded by shale. If the cement degrades over time, what will the impact of this shale swelling be? Stephen confirmed that situations where wells are observed in areas with poor quality cement jobs with good shale swelling, the long-term integrity appears to benefit. After a period of a few weeks in these situations, the repeated tests show that the integrity has improved over time; however it is unclear if this is due to the cement setting slowly or the shale has encroached. The general consensus is that the swelling has resulted in a benefit.

3.8 Testing Zonal Isolation with a Cased Hole Formation Tester, Adriaan Gisolf, Schlumberger

Adriaan Gisolf presented work covering case studies of cement integrity and the tools used to determine and take monitoring data. Case studies described the materials and processes of testing isolation, and the issues associated with each method were explained. The cases cited included both the demonstration of isolation and the discovery of zonal communication.

Adriaan answered some technical questions about the capabilities of the tool used, explaining that different elements could be added and included to vary the parameters measured and variations in the permeability, such as in the different areas of the formation as well as the caprocks, although the caprocks were not measured in this instance. The tool can measure down to around the 0.1 mD range.

Andrew Duguid confirmed that he too had used similar tools to measure cement permeability, but the technique for the analysis is completely different. To his knowledge, no one has performed the same tests on caprocks yet.

3.9 Joslyn Creek SAGD Thermal Operations, Fran Hein, ERCB

Fran presented this case study of a steam well blow out, resulting in damage to pipelines and caprocks. The well that blew was 60m deep. The presentation explained the investigation into the situation and conditions that led to the event.

Inge Carlsen asked what the future for the SAGD processes in that field would be. Fran explained that there were various remedial actions the company was required to complete, and the ongoing monitoring programme was upgraded. After 18 months of ongoing measurements, the company have withdrawn their application to continue to operate the site.

3.10 Temperature Instrumentation, Jan Henninges, GFZ

Temperature monitoring equipment is being tested at the Ketzin CO_2 injection site in Germany, with temperature monitoring aimed to measure potential fluid migration during the injection into the saline aquifer and to determine the thermal state of the borehole and the reservoir.

Laure Deremble asked where the video shown as part of the presentation was taken, and Jan confirmed it was from a camera inside the observation well. The rest of the data was obtained from both injection and observation wells.

A question arose over the statement that the accuracy of the measurements is said to improve over time. Jan explained that the data was averaged over time, therefore reducing the error and improving the accuracy.

3.11 Discussion Session 3: What are the Aspects that need further work/research? Do we need to focus on practical projects?

Bill started the final discussion session of the meeting by inviting delegates to bring up any issues that are of interest, maybe issues that have not been previously discussed. Fran Hein started with an update outlining a briefing note of a Canadian well drilled in 1985, later converted to acid gas disposal from 1994 onwards. The application has been amended to use the overlying formation as a disposal zone, and the operators were asked to demonstrate that the acid gas was contained. The logs were able to demonstrate that this was not the case, and the acid gas has migrated into the overlying proposed disposal zone. An increase in monitoring is therefore being requested. The point here is that there was no previous indication of leakage, and we now know that leakage has occurred to a depth of 64m above the original disposal zone: how do we detect this in the future before it becomes an issue or before we actively look for it?

Bill brought up the topic of being able to fix wells, which we know we can do, and the difference between this, and knowing how many wells we are likely to have to fix in any given field. There are general ideas of how many wells will require action, but no clear indication, other than such databases as the Shell database presented this morning. If access to this can be granted widely, then predictions can be made much more accurately as to likely requirements for re-assessment of wells and the associated costs of such activities. If the CO_2 enters the annulus, but there is no bleed off, then there is no problem – the CO_2 will erode the casing a little, but then nothing will happen, and there is no impact. The other issue is of the self-healing tendencies, and the role this mechanism may play. From the talks at this meeting, what level of contribution can be made by clays and shale's as self sealing mechanisms: all these possibilities will impact which wells, and how many wells need to be investigated.

Mike Celia proposed a different approach – we would like to be able to say something about where the CO_2 will go over time; if we project past the operational phase, and then on for 100 years, the objective becomes assessing the fate of transport. Does the CO_2 stay where it is injected, or does it progress to overlying strata? We are trying to develop tools that allow probabilistic assessment of the likelihood of such occurrences.

Some well data may allow us to predict the fate of transport, from one level to another, and this moves us away from clear cut choices of 'this is good, this is bad'. A dataset with 15,000 wells and data on average repair timescales and costs is very useful information. The RP90 assessment had access to hundreds of thousands of wells as the MMS (Mineral Management Service) was on the committee so they were able to access to the MMS database. The problem was that they ran out of money before being able to finish the study. RP90-b, which was intended to assess the risk element, was never completed. The preliminary study showed it was feasible, but there weren't the funds to allow completion. It could still be done, but the money must first be found.

Paul Hopmans asked if there was any opinion from DNV on the risk element from their work, Mike Carpenter suggested that as far as dispersion modelling of CO_2, there is a lack of experimental data to support the models, and this is an ongoing project in the UK and USA to generate data on this. As far as defining acceptable criteria in terms of leakage rates, the ambition is to establish dialogue between regulators and operators to try to define and quantify acceptability.

Legislation suggests that it shouldn't go outside the containment zone, so this suggests no leakage in principal, which leads to discussions on the definition of a leak. Seepage may not equate to leakage, so this definition is key to future work. Is the definition of a leak that which can affect pressure of higher strata or just escape from target reservoir? Issues associated with offshore scenarios are that leakage is harder to detect, even following terrible abandonment practices, as any CO_2 bubbles will disperse completely by the time they reach the surface, and to an extent the same is true in subsurface for onshore operations. It all comes down to risk rates, and what is deemed acceptable.

Neil Wildgust suggested the debate on seepage and leakage has gone on for some time and will likely continue for some time further. According to the EU Directive on CCS, you have to define the storage container, and this can encompass more than one reservoir and more than one caprock. So a zero leakage assumption means you design a site so that it won't leak, but also have contingency plans to deal with the probability and impacts of leaks, should they occur. If an operator states that leaks are likely, a permit won't be issued. The carbon trading system within Europe will state that if leakage back to the atmosphere occurs, then heavy penalties will apply until corrective measures are in place and operative. Key HSE impacts relate to the momentum of release. Suggestions of rapid release, such as might be expected from a pipeline or well blowout, result in rapid dispersal and minimal risk, whereas the lake Nyos incident showed a much slower leak rate, which did not therefore disperse and caused the well-publicised problems.

Frank van Dam suggests if small quantities of CO_2 leak back to the atmosphere it's not a problem, but this will not be acceptable to legislation and emissions trading programmes. The probability of the timescales involved will mean that we can't be certain, but operators will need to be able to be as confident as possible that abandonment will be effective. If it is assumed that there may leak a small initially, and that this will self seal over time, and remove the issue, it is conceivable that the only issues will be short term, and over the longer term, there will be no problem and a reduction in risks, but again this assertion is unlikely to be acceptable under legislation.

The other issue is that CO_2 is not too dangerous compared with other gases that are in the subsurface, and this should be remembered. The issues should mainly be focussed on seepage into any groundwater systems. The US EPA is primarily concerned about protection of drinking water, which demonstrates the importance of this aspect.

Mike Celia suggested we need to change the timescale reference – CCS is all about climate change, and the natural climate variation in will mean that we actually need to store CO_2 for around 1000 years, not the 10,000 years that some models quote and we need not work to such long scales. The risks reduce after injection stops, and if you get to the end of the operational phase and things look good, then we can be confident. The EU Legislation says it must be infinitely stored, but Mike Celia suggests this isn't a problem, the longer the CO_2 is there the safer it becomes. The climate timescale should be the main focus after the 50 years operational stage. So we should see 3 periods; operation, 1000 years, then infinite / permanent storage.

The discussion is good, but the consensus appears that we need to reach a decision on what risks we are quantifying and what standard we should use and define. Do we need to quantify which wells are liable to need repair, or do we just use a risk ranking to identify the wells to be targeted.

The API suggests operators should work on a 20% threshold of the weakest element; so you take the weakest well in a field and determine the pressure threshold that that would result in a blowout and the field limit is therefore 20% of that pressure. This is very strict as anything over 20% of this pressure will require remediation.

Bill Carey suggested that if a well has been worked over, then that well can be considered to not pose a risk, but some risk processes define risk as a frequency per well per year, so this would require constant and ongoing observation of every well, even if it has been reworked to the best possible standard. If a well has been reworked, do you assume it is fixed, or that as it has had problems, it may have problems again? Ron Sweatman suggests that if you define a well as permanently abandoned, the leakage must be zero, and this is rarely the case.

Sarah Gasda suggested that all these discussions suggests that all leakage goes via SCP rather than any other route, and this is unlikely to be the case and will also only apply to recent wells – not the older wells that are accepted as more likely to be a problem. Mike Parker said that in this case you would have to re-plug every well regardless. Occasionally if the records verify that the well is plugged to the applicable standards then maybe you can skip it, but usually you would have to do all.

Bill thanked the delegates for their input over the past two days, and passed the floor to Neil for closing comments.

Session 4: Summary, Discussion and Close

Neil closed the meeting thanking the delegates, chairs, particularly bill and the steering committee and shell as hosts and sponsors. Neil outlined the possible next meeting in Perth, and the manner in which we select venues.

The meeting showed a move towards agreement with regard to future focus. It was generally agreed that recent wells and those wells which will be drilled in the future are not likely to cause problems in terms of wellbore integrity; moreover we can determine that older wells are more likely to be of concern, and specifically, the older the wells, the more likely the need for remedial work or re-abandonment.

Although experiences vary as to the precise age that well abandonments can become problematical, there was a definite consensus that fields can be assessed and risk managed according to the records of well placement and well abandonment and the periods of operation and abandonment.

The increased focus on the concept of self-healing micro-annuli demonstrates a development of knowledge not previously seen, and it can be expected that future cement-based research will increasingly focus on this, amongst other issues.

ieaghg

6th Wellbore Integrity Network Meeting

Noordwijk Aan Zee

Evaluating technology options to mitigate greenhouse gas emissions

28th-29th April 2010
Noordwijk Aan Zee, The Netherlands

Organised by

IEAGHG and Shell

Hosted and Sponsored by

Shell

28th April 2010 Day 1

08.00 to 09.00 Registration	
09.00 to 09.30	Welcome by Shell: Davie Stewart, Vice President, Wells Discipline
09.30 to 09.40	Welcome and Outline of Agenda: Bill Carey, Network Chair
Session 1: Regulation and Classification Guidelines	
09.40 to 09.45	Introduction to session:
09.45 to 10.10	TNO Study, Well Abandonment Review: Muriel van der Kuip; TNO
10.10 to 10.35	ERCB Injector Well Classification: Fran Hein; ERCB
10.35 to 10.55 Coffee Break	
10.55 to 11.20	DNV JIP, Early Status and Potential Input from WBI Network; Mike Carpenter, DNV
11.20 to 12.00	Discussion Theme: Impact of regulations, input to JIP: Potential for Network to input to JIP suggestions for research direction.
12.00 to 13.30 Lunch	
Session 2: Experimental Developments/Discussions	
13.30 to 13.35	Introduction to session
13.35 to 14.00	Evolution of Cement Mechanical Properties: Brice Lecampion; Schlumberger
14.00 to 14.25	Experimental Wellbore Corrosion Work: Bill Carey; LANL
14.25 to 14.50	Stability of Leakage Pathways along a Cement Annulus: Laure Deremble; Schlumberger
14.50 to 15.15	Experiments on Cement Carbonation in a Brine Reservoir: Controversy or Consistency?: Bruno Huet; Schlumberger
15.15 to 15.45 Coffee Break	
15.45 to 16.10	Cement Performance: Andreas Brandl; BJ Services
16.10 to 16.35	Mechanical Integrity of Cement: Emilia Liteanu; Shell
16.35 to 17.15	Discussion Theme: Are we confident of new wells—should we focus on work-over of old wells?

Close Day 1
18.00 –19.00 Reception/drinks
19.00 Dinner at the Restaurant Chatillon

29th April 2010 Day 2

Session 3: Projects and Practical Experiences	
08.30 to 08.35	Introduction to session
08.35 to 09.00	Grooved Horizontals for Extended Reach Injectors: Inge Carlsen; SINTEF
09.00 to 09.25	Managing Wellbore Integrity of Large Wells: Paul Hopmans; Shell
09.25 to 09.50	DOE Funded Wellbore Survey Investigations: Andrew Duguid; Schlumberger
09.50 to 10.15	CO_2 Injector Remediation, API CCS Taskforce: Ron Sweatman; API
10.15 to 10.45 Coffee Break	
10.45 to 11.10	Risk of Leakage Through Wellbores; Is It Really That High?: Matteo Loizzo; Schlumberger
11.10 to 11.35	Sustained Casing Pressure, Analysis as an Analogue for CO_2 Leakage along a Wellbore: Case Study Results and Limitations: Nicolas Huerta; University of Texas
11.35 to 12.00	Recognising Wellbore Collapse: Stephen Williams; Statoil (via video link)
12.00 to 12.25	Testing Zonal Isolation with a Cased Hole Formation Tester: Adriaan Gisolf;Schlumberger
12.25 to 14.00 Lunch	
14.00 to 14.25	Joslyn Creek SAGD Thermal Operation: Fran Hein; ERCB
14.25 to 14.50	Temperature Instrumentation: Jan Henninges; GFZ
14.50 to 15.20 Coffee Break	
15.20 to 16.00	Discussion: What are the aspects that need further work/research? Do we need to focus on practical projects?
16.00 to 16.20	Discussion on network future
Close Day 2	

ATTENDEE LIST

6th Wellbore Integrity Network Meeting

28th-29th April, 2010 Noordwijk Aan Zee, Netherlands

Toby Aiken, IEAGHG
Onajomo Akemu, Schlumberger Carbon Services
Mingxing Bai, Institute for Petroleum Engineering
Axel-Pierre Bois, CurisTec
Andreas Brandl, BJ Services Company
Bill Carey, Las Alamos National Laboratory
Patricia Carles, Air Liquide
Inge Carlson, SINTEF
Mike Carpenter, DNV
Frank van Dam, Shell
Laure Deremble, Schlumberger
Andrew Duguid, Schlumberger Carbon Services
Rob van Elsen, Dutch State Supervision of Mines
Hrvoje Galic, BP Alternative Energy
Sarah Gasda, University of North Carolina
Adriaan Gisolf, Schlumberger
Isaline Gravaud, BRGM
Ferdinand Gubler, Dutch State Supervision of Mines
Frances Hein, Energy Resources Conservation Board
Hein van Heekeren, Well Engineering Partners
Jan Hennings, German Research Centre for Geosciences
Paul Hopmans, Shell
Nicolas Huerta, University of Texas at Austin
Bruno Huet, Schlumberger
Vincent Hugonet, Shell
Martin Jagger, Shell E&P
Ines Khalfallah, Schlumberger
Muriel van der Kuip, TNO Built Enviroment & Geosciences
Brice Lecampion, Schlumberger
Eric Lécolier, IFP
Emilia Liteanu, Shell International Exploration & Production
Matteo Loizzo, Princeton University
Ulrike Miersemann, Schlumberger
Michael Parker, ExxonMobil production Company
Marleen Peters, Shell
Cristine Richard d Miranda, Petrobras
Daniel Quesada, Schlumberger
Brice Robert, TNO
Andreas Ruch, Halliburton
Dave Ryan, Natural Resources Canada
Jon Samuelson, Utrecht University
Steven Smith, Energy & Environment Research Centre
Ronald Sweatman, Halliburton
Rosana Fatima Texeira Lomba, Petrobras
Trach Tran-Viet, State Authority for Mining Energy & Geology
Stephen Williams, Statoil
Berend Antoine Verberne, Utrecht University
Michael de Vos, Dutch State Supervision of Mines
Xiaolong Zhang, TNO

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Xiaolong Zhang, TNO

Well Abandonment Practices

IEA GHG 6th Wellbore Integrity Network Meeting
Noordwijk, April 28, 2010

TNO | Knowledge for business

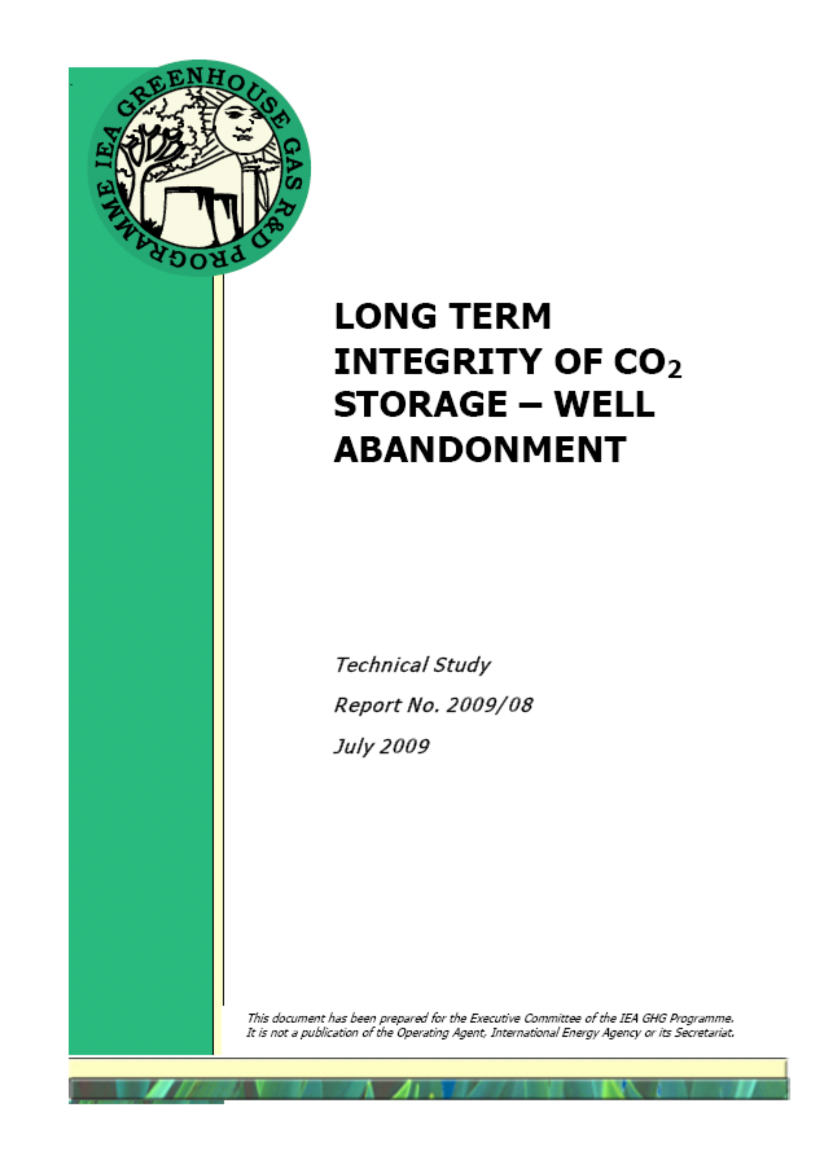
Muriel van der Kuip, Tjirk Benedictus, Brice Robert

Introduction

- In 2009 TNO conducted a review study for IEA GHG into well abandonment practices based on available literature

- Results are published as IEA GHG report – Technical Study 2009/08

- At 5th Wellbore Integrity Meeting in Calgary draft version was presented



IEA GREENHOUSE GAS R&D PROGRAMME

LONG TERM INTEGRITY OF CO_2 STORAGE – WELL ABANDONMENT

Technical Study

Report No. 2009/08

July 2009

This document has been prepared for the Executive Committee of the IEA GHG Programme. It is not a publication of the Operating Agent, International Energy Agency or its Secretariat.

Scope of the study

- Previously abandoned deep oil and gas wells
- Well abandonment techniques – *historical developments*
- High order evaluation of abandonment practices:
  - Expert opinions (questionnaire)
  - Governing regulatory frameworks
- Overview of state of knowledge on well material degradation
- Risk management
- Recommended best practice

Future and existing wells

- Future wells
  - Wells directly related to CO_2 storage operations (i.e. CO_2 injection or monitoring wells)
  - Wells penetrating or transecting CO_2 storage reservoirs aiming at reservoirs at deeper levels

  To be designed and abandoned taking into account CO_2 storage

- Existing wells
  - Accessible wells (e.g. operating, shut-in)

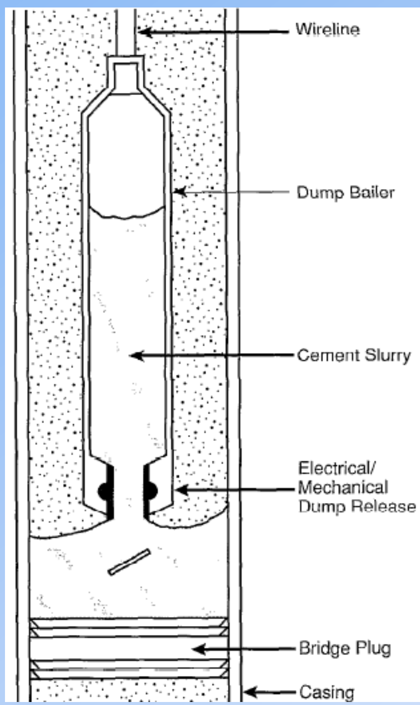
  To be abandoned taking into account CO_2 storage

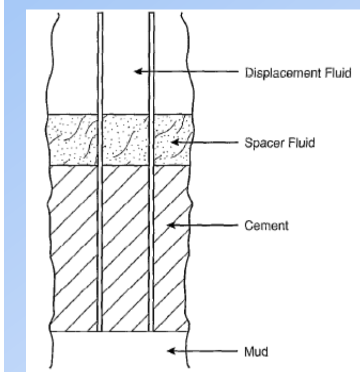
  - Previously abandoned wells

  Main risk for well integrity (leakage)

Historical development - well abandonment

▶ Plugging techniques

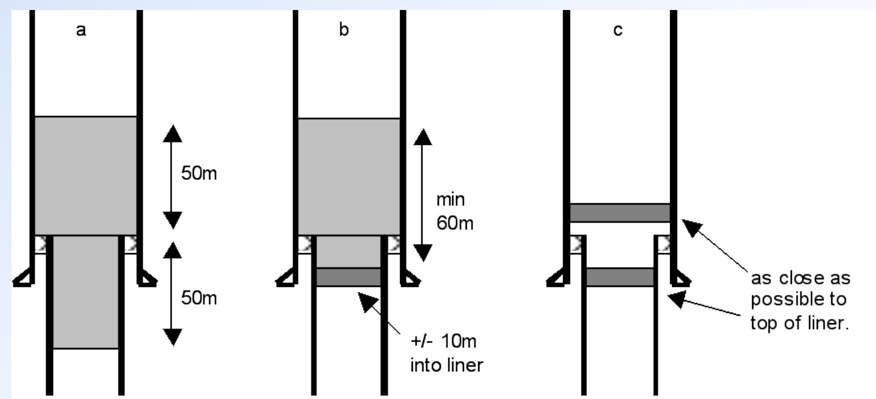




After: Nelson and Guillot, 2006

▶ Materials

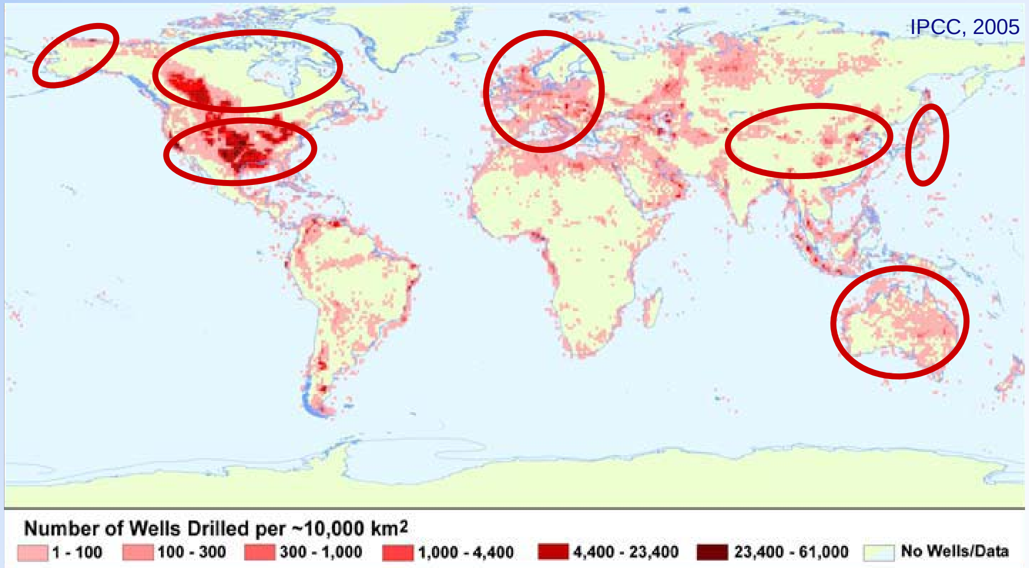
▶ Regulations



Dutch Mining Act, 2003

Well Abandonment Regulations

- Well abandonment requirements in international regulations - Literature survey
  - Australia
  - Canada
  - China
  - Europe (e.g. Denmark, Netherlands, Norway, UK)
  - Japan
  - USA (Alaska, California, Texas)



- Data obtained of plug lengths and position requirements used in;
  - transition zone from uncased to cased sections
  - reservoir (uncased) section
  - perforated cased sections

Selection of minimum plug requirements

- Transition zone from uncased to cased sections;
  - Europe; 50-100 m, except UK; 30 m
  - International; 30-60 m, except Canada; 15 m depending on formation

- Reservoir (uncased) section
  - Europe and International; 50-100 m,
    except UK and Canada; 30 m

- Perforated cased sections
  - Europe; 50-100 m, except UK; 30 m
  - International; 30-60 m, except Canada; 80 m

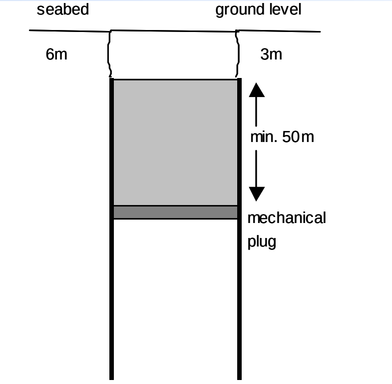
Note: plug lengths in feet have been converted into meters and rounded off

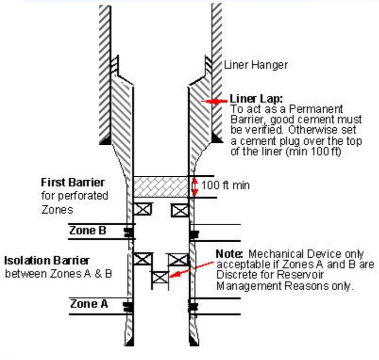
Review of abandonment regulations

- First order proxy for initial identification of abandonment practices only

- Cement plug is compulsory in all evaluated regulatory documents

- Main differences:
  → plug requirements (lengths) at the level of the deepest casing shoe
  → exact requirements concerning additional cementing (if applicable) differ significantly among regulations





Note that reviewed documents often involve unofficial translations of the original documents from the native languages to English

Questionnaire: abandonment practices

- Survey/questionnaire presented to approximately 200 experts;
  - Operators, service companies, research institutes, regulatory bodies

- Topics are:
  - Abandonment regulations
  - Drilling & completion operations
  - Abandonment practices
  - Data availability

- 9 responses
  - From North America, Europe, Australia

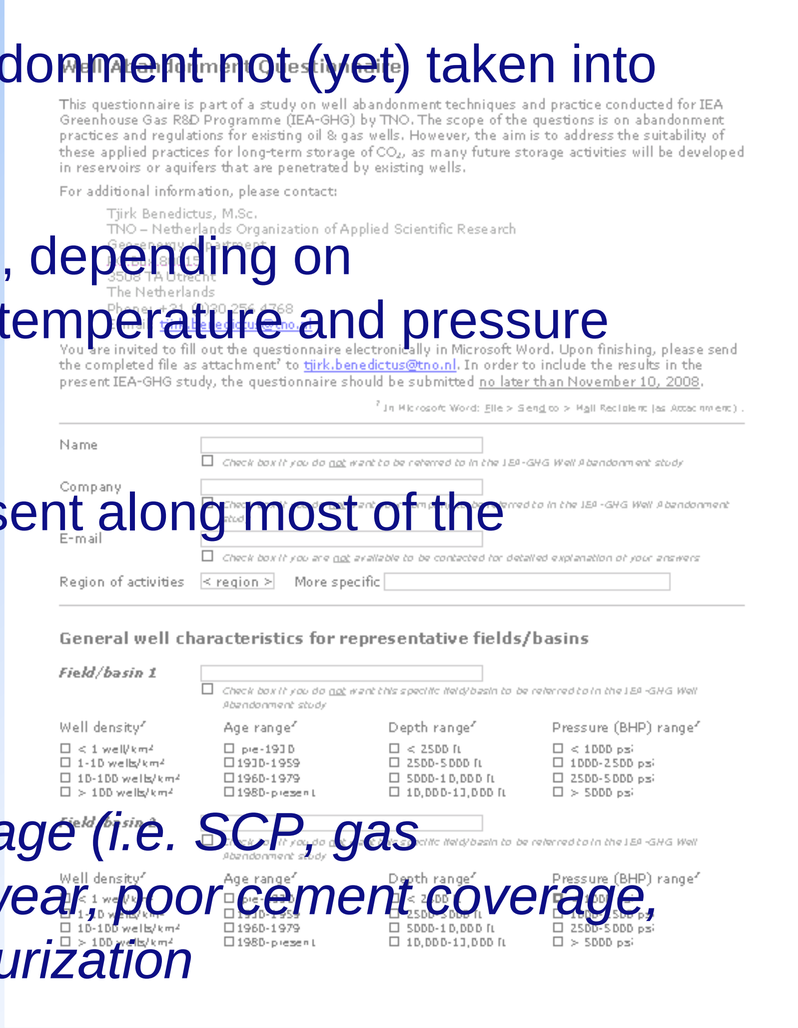
Questionnaire: Abandonment regulations

- Company practices closely reflect governing regulations
  - Regional or national regulations, or (in absence of these) international guidelines (OSPAR, London Convention)

- Most commonly prescribed → Balanced plug method
- Number of plugs → 1 to 3
- Plug length → 8 to 100 m
- Plug testing → Weight or pressure test
- Requirements for corrosive environments → Rarely in place

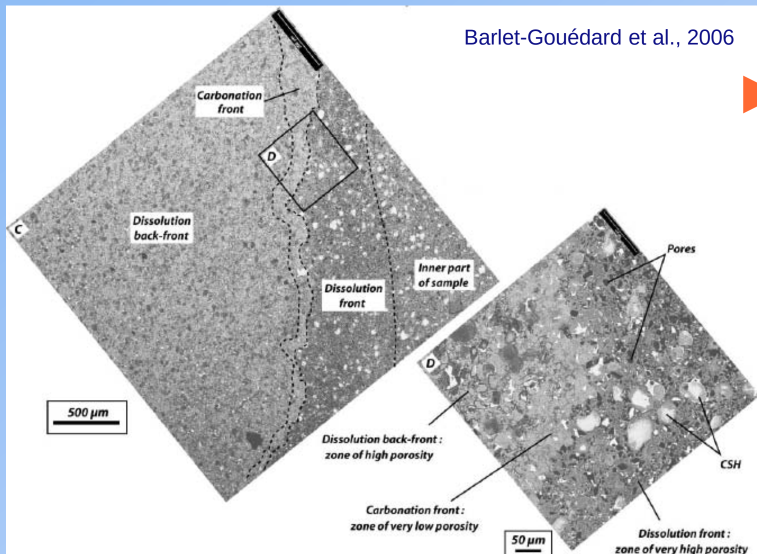
Questionnaire: Abandonment practices

- Second life applications during abandonment not (yet) taken into account
- Various steel grades used for casing, depending on
  - (API) guidelines on H_2S content, temperature and pressure
  - corrosive environments
- Primary cement sheath typically present along most of the wellbore
- Well data is usually available
- *Some wells (<30%) show initial leakage (i.e. SCP, gas migration), due to casing corrosion/wear, poor cement coverage, improper slurry design, or overpressurization*

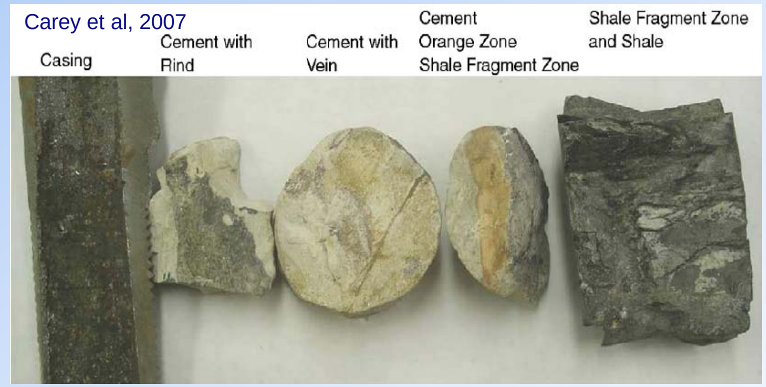


Muriel van der Kuip, Tjirk Benedictus, Brice Robert

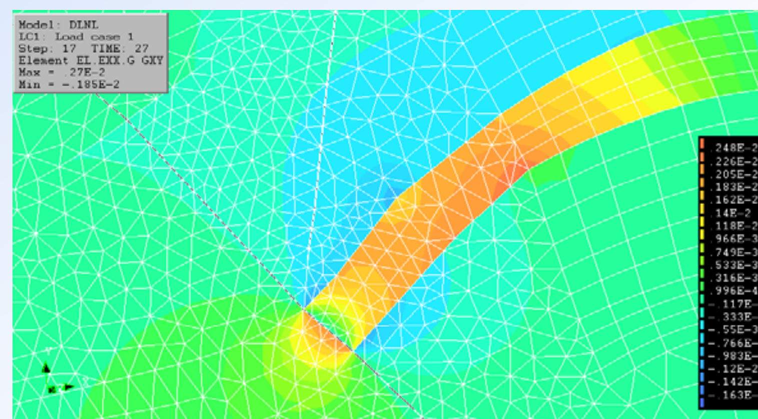
Impact of CO_2 on wellbore integrity: an overview



► Cement degradation



► Mechanical deformation



► Steel corrosion

Carbonic acid formation:

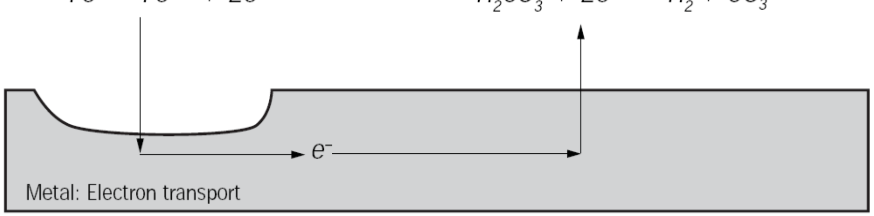
$$CO_2 + H_2O \leftrightarrow H_2CO_3$$

Anodic reaction:

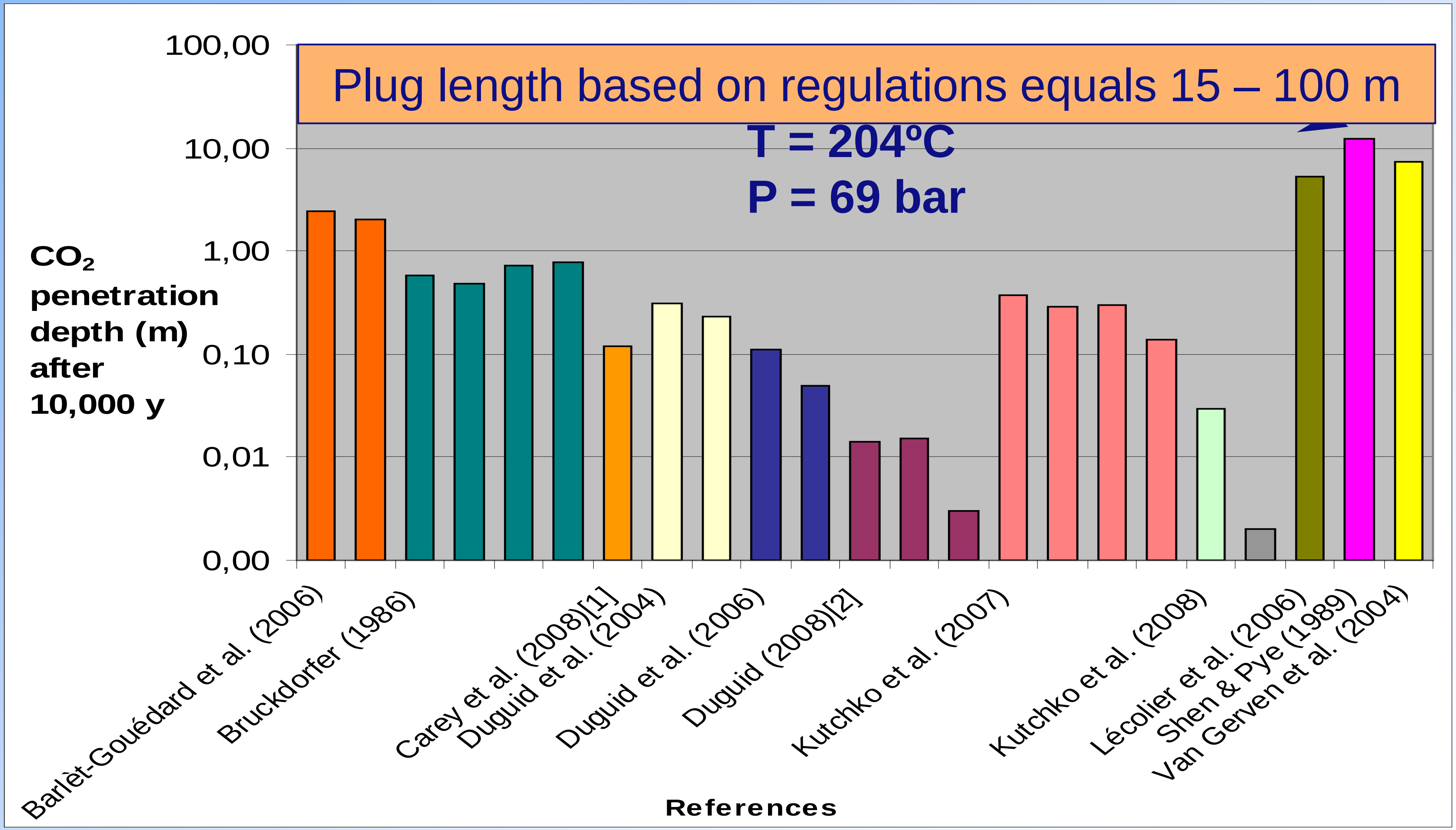
$$Fe \leftrightarrow Fe^{2+} + 2e^-$$

Cathodic reaction (on the steel surface):

$$H_2CO_3 + 2e^- \leftrightarrow H_2 + CO_3^{2-}$$

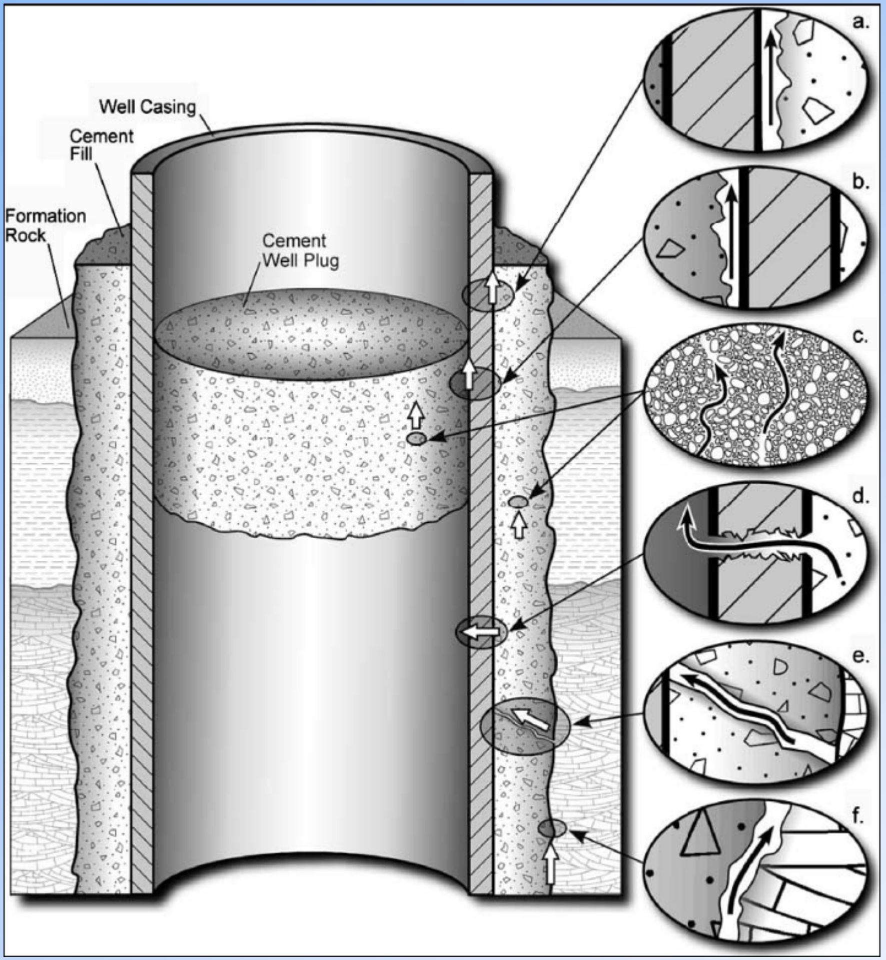


Cement degradation – literature survey



Note: comparison without taking into account different cement types, P, T, pH, estimated/derived diffusion coefficients between the references.

Impact of CO_2 on wellbore integrity: an overview



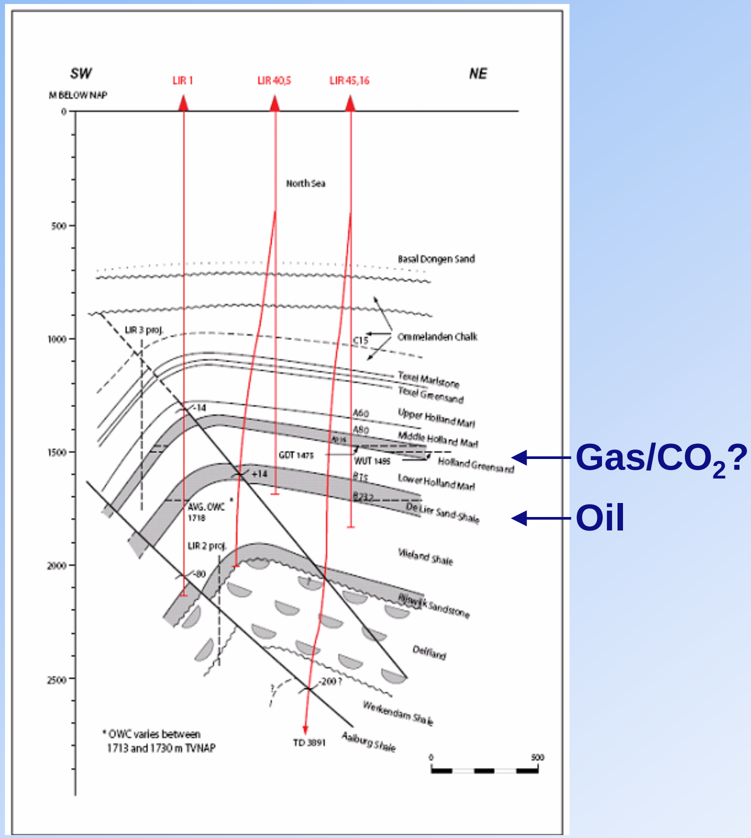
After Gasda et al. (2004)

- Interaction of casing corrosion and cement degradation along micro annuli
- Interaction of chemical, mechanical and physical processes

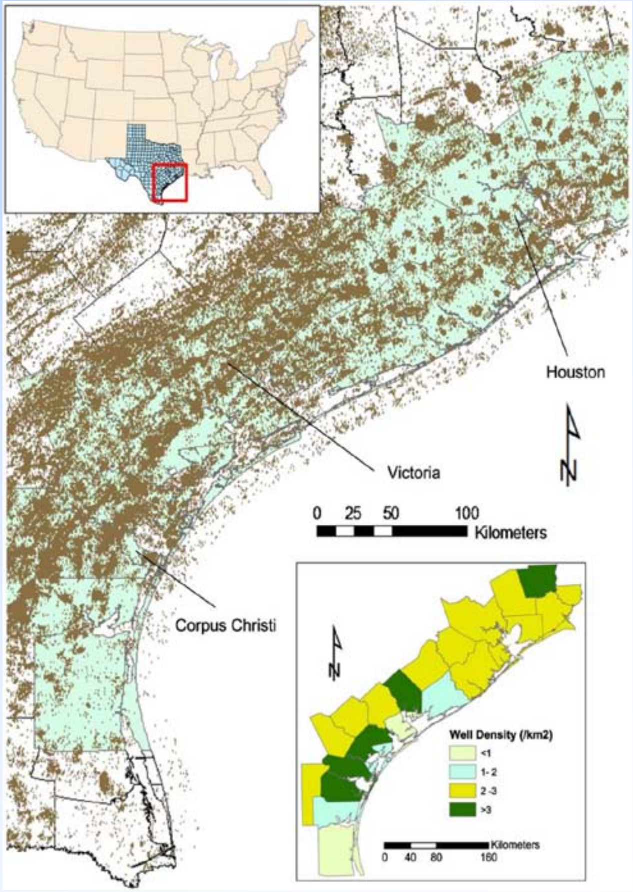
→ *mechanical processes more significant than chemical degradation*

Case studies

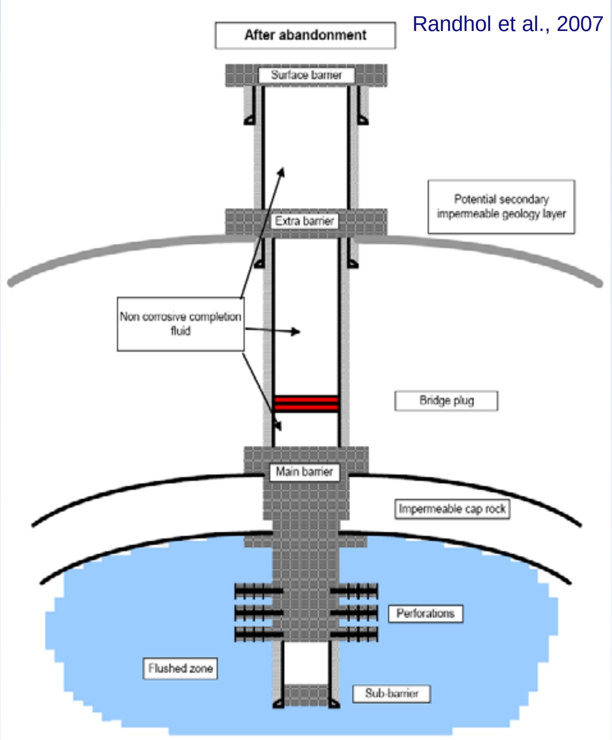
De Lier (the Netherlands)



Gulf Coast, Texas (USA)



Recommended best practice



- Future wells designed, drilled, completed and abandoned taking into account any CO_2 storage reservoirs
  - State-of-the-art well abandonment practice
  - Advanced materials and methods
- Suitability of existing wells for CO_2 storage needs to be evaluated
  - Accessible wells;
    - workover operations based on techno-economical considerations
  - Non accessible wells;
    - older wells vs. newer wells
    - timing and stringency of global abandonment regulations varies considerably

Managing previously abandoned wells

- Lessons learned from field cases important when considering second life applications

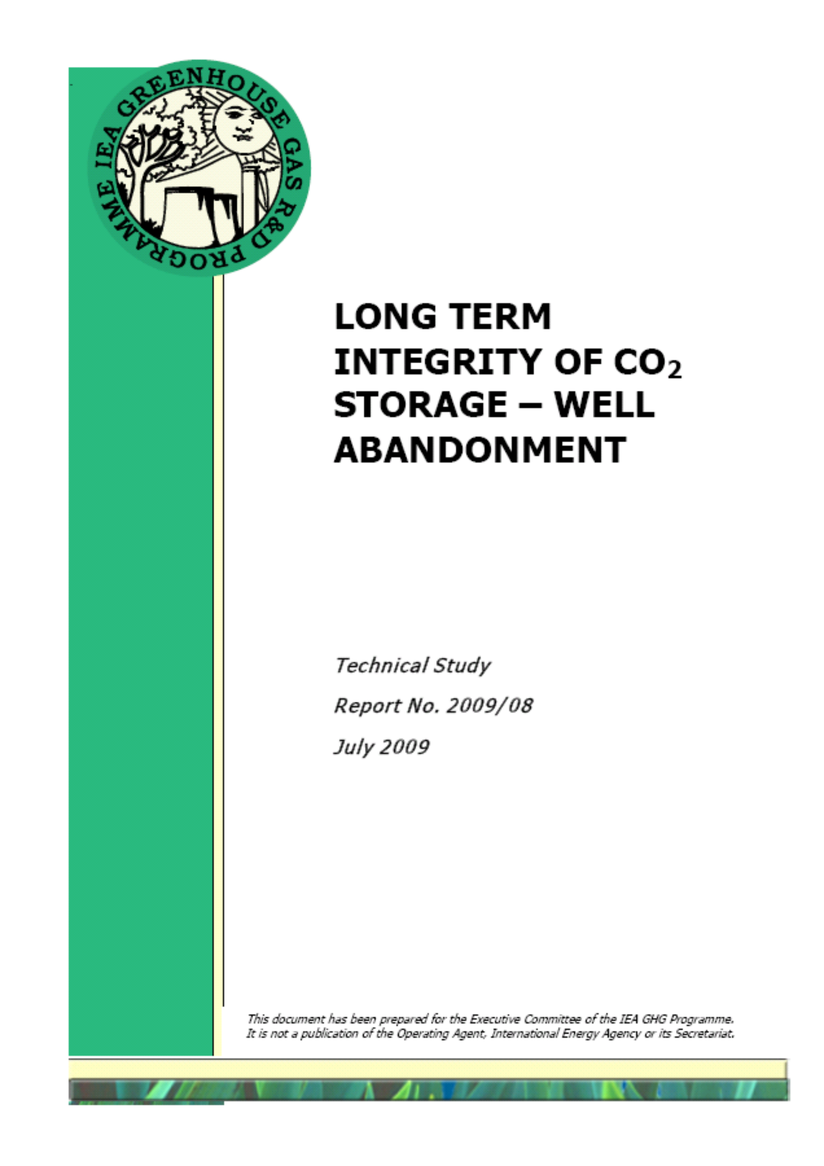
- Quality and mechanical integrity of cement plug and sheath seems to be of more significance than chemical degradation:
  - Fractures or annular pathways in or along the cement will likely govern the permeability of the wellbore system

- Risk management; assess the current state of the wells involved and possible adverse effects associated with CO_2 storage

Thank you!

For more information please contact:

muriel.vanderkuip@tno.nl
tjirk.benedictus@tno.nl
brice.robert@tno.nl


IEA GREENHOUSE GAS R&D PROGRAMME

LONG TERM INTEGRITY OF CO_2 STORAGE – WELL ABANDONMENT

Technical Study

Report No. 2009/08

July 2009

This document has been prepared for the Executive Committee of the IEA GHG Programme. It is not a publication of the Operating Agent, International Energy Agency or its Secretariat.

ERCB Energy Resources Conservation Board

6th Well Bore Integrity Network Meeting

Alberta ERCB
CO_2 Injection Well Classification
The Hague, The Netherlands
April 28-29, 2010

Dr. Fran Hein, P.Geol., Chief Geologist ERCB
Theresa Watson, P.Eng.
Herb Longworth, P.Eng.

ieaghg

The Alberta Energy Resources Conservation Board (ERCB) is a quasi-judicial Board enabled by legislation who, among other things, regulates the design, construction, cementing, testing, monitoring, and abandonment of wells associated with oil and gas production in the province of Alberta, Canada. This includes CO2 injection wells.

web link: http://www.ercb.ca

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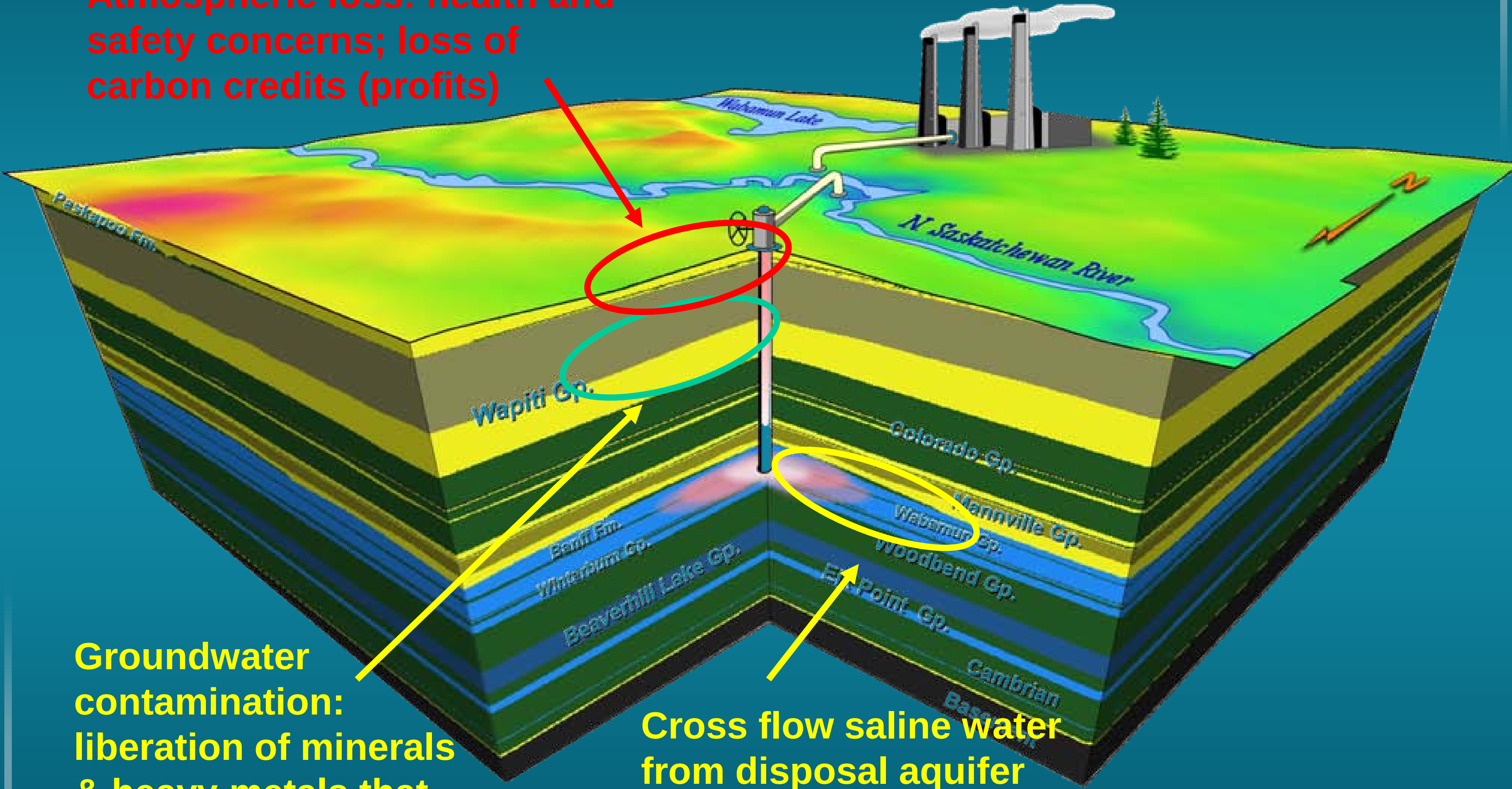
Wellbore Integrity Concerns Re: CO_2 Injection

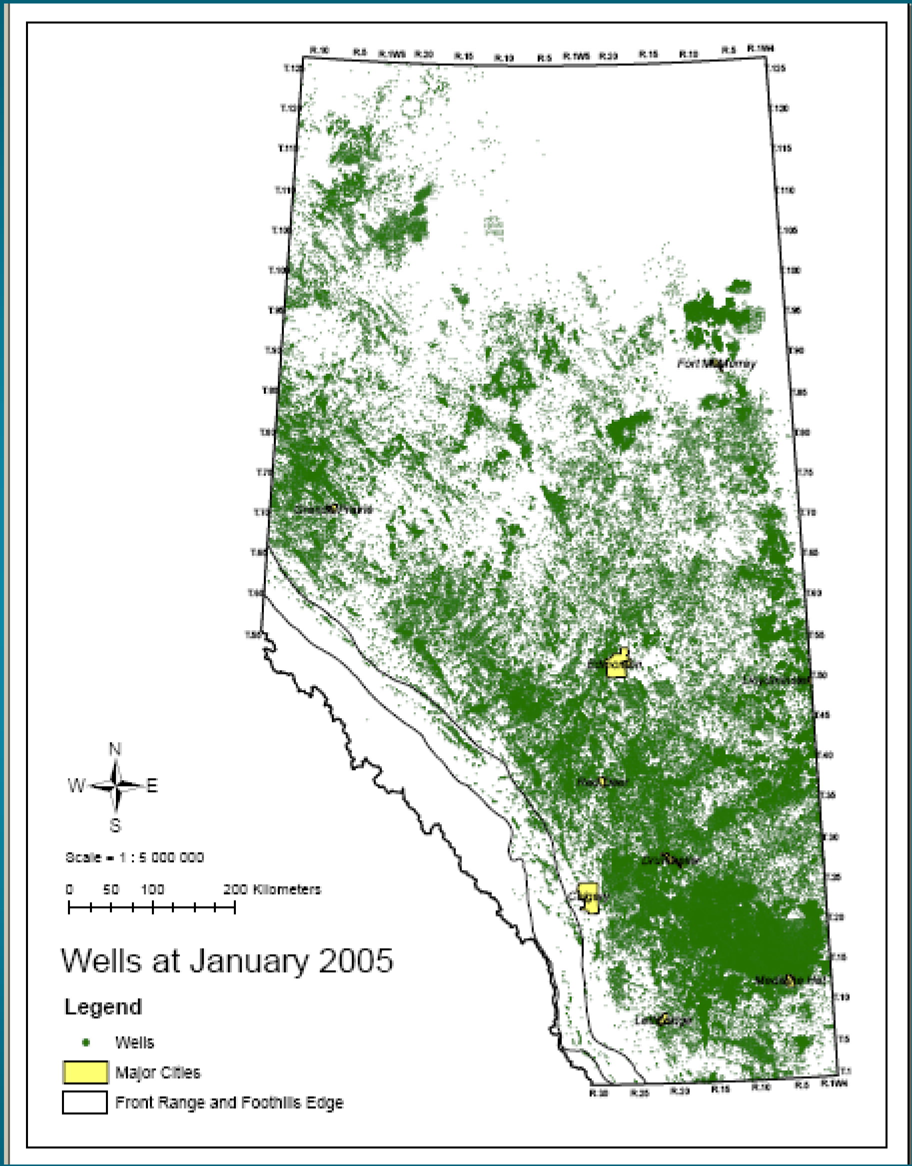
Atmospheric loss: health and safety concerns; loss of carbon credits (profits)

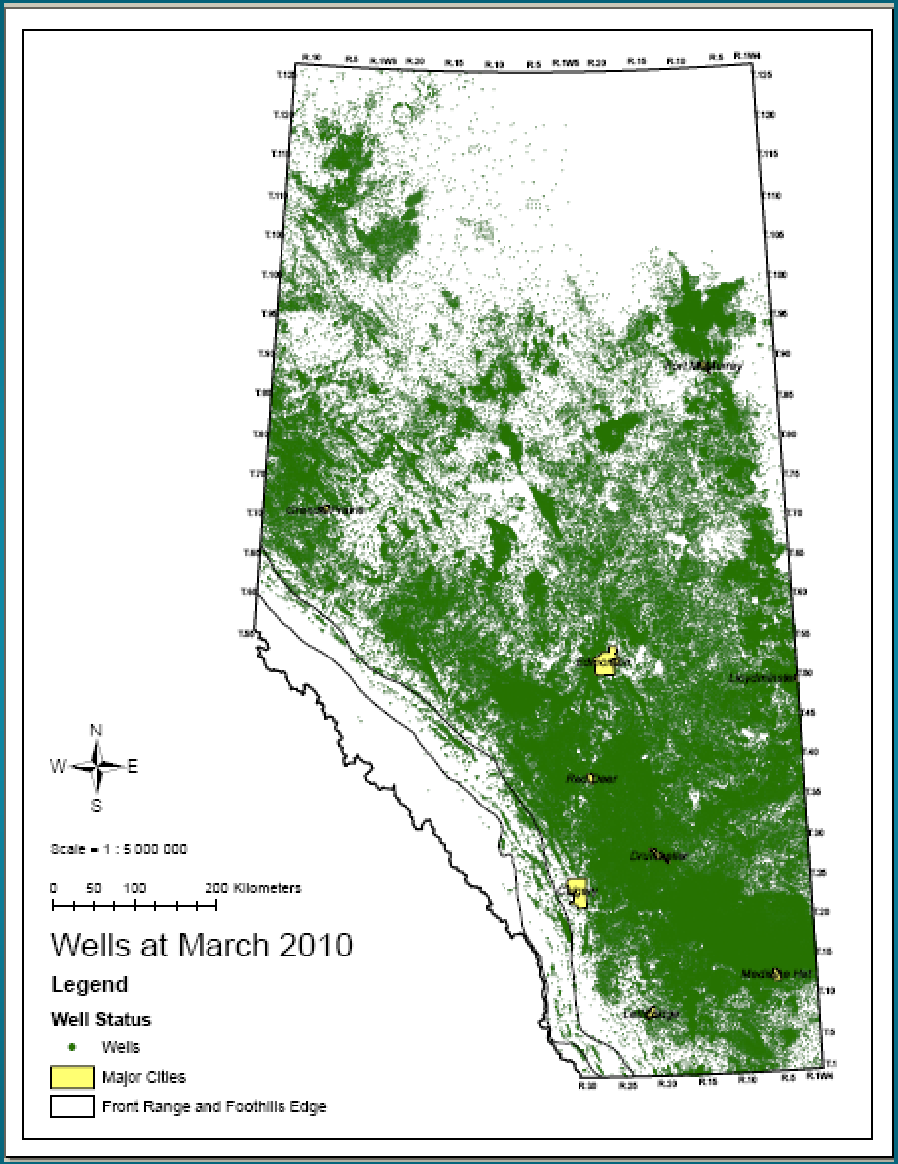


Groundwater contamination: liberation of minerals & heavy metals that may be toxic

Cross flow saline water from disposal aquifer into other subsurface aquifers or upper groundwater zones

Wells 01_ 2005 vs. 03_2010





Wells = 321, 497

Wells = 410, 027

Ongoing Well Evaluations

- **What should we be evaluating that might trigger an operating or abandoned well work-over within a CO2 injection pressure plume?**
  - **Casing Integrity**
  - **Cement and Cement Bond Integrity**
  - **Tubing and Packers**
  - **Formation Fluid Changes**

Base Line Information

- Sampling for Soil Gas and Surface Casing in All Seasons
- Ground Water Testing
- Porous Zone Above Caprock Characterization (Fluid, Pressure, etc.)
- Cement Bond Log /Casing Inspections
- Other Logging For Water, Gas or CO_2

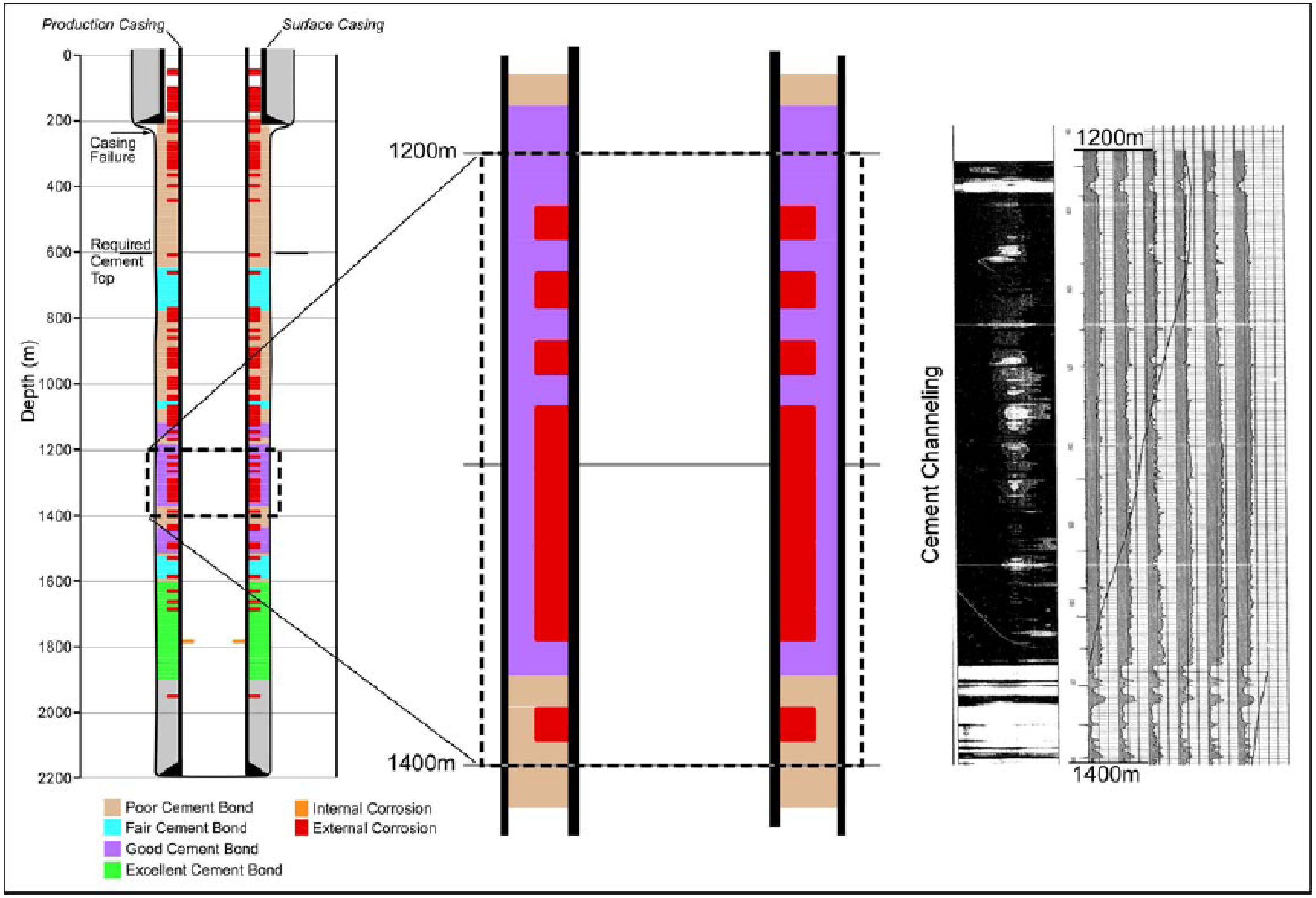
Ongoing Monitoring

- **Injectors**
  - Radioactive tracer logs have shown migration outside of casing between cement and formation.
  - Annual test help to show changes, not just empirical measurement.
- **Cased Wells**
  - Combination of cement evaluation and casing inspection (must directly indicate external corrosion)
  - Change in casing condition is easier to detect than subtle changes in compressive strength

Watson, T.L., 2009. CO2 Storage: Wellbore Integrity Evaluation and Integrity across the Caprock; SPE 126292, Presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, USA, 2-4 Nov, 2009.

Combination Casing Inspection & Cement Evaluation

Figure 14: Example of well log analysis showing cement bond quality and casing corrosion with example of corrosion due to cement channeling in good cement.



Watson, T.L., Bachu, S. 2007. Evaluation of the Potential for Gas and CO2 Leakage Along Wellbores; Paper SPE 106817, Presented at the SPE E&P Environmental and Safety Conference, Galveston, USA, 5–7 March.

What You May Not Know Maybe Critical

- **Factors that may impact wellbore integrity or cause concern due to unknown conditions:**
  - Cement of unknown quality and type;
  - Unknown mud properties (such as oil based muds with no spacers run to protect cement from contamination);
  - Cement top not located to confirm location;
  - Occurrence of abandoned open-hole wells or not properly abandoned cased wells in the vicinity that may be conduits for communication to surface groundwater or natural fractures and faults.

Watson, T.L., 2009. CO2 Storage: Wellbore Integrity Evaluation and Integrity across the Caprock; SPE 126292, Presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, USA, 2-4 Nov, 2009; ERCB Staff Review and Analysis. Total E&P Canada Ltd., Surface Steam Release of May 18, 2006, Joslyn Creek SAGD Thermal Operation, January 19,2010, ERCB Bulletin 2010-10, http://www.ercb.ca

ERCB Well Integrity Directives

- **Dir 51 – Wellbore Injection Requirements**
- **Dir 08 – Surface Casing Min. Depth**
- **Dir 09 – Casing Cementing**
- **Dir 10 – Min. Casing Design**
- **Dir 36 - Drilling Blowout Prevention**
- **Dir 20 – Well Abandonment**

Details can be found at:
http://www.ercb.ca/portal/server.pt ?
Select <Industry zone>; <Rules,Regulations…>; <Directives>

Focus on Directive 51: Wellbore Injection Requirements

- **First implemented in 1994: Prior to that was done on a case-by-case basis.**
- **Provided basis for approval of more than 50 acid gas disposal schemes in Alberta between 1994 and 2010.**
- **Directive 51 (D51) is currently being updated**

Different Well Classes Cover Injection of:

- **I – Common Oilfield Waste**
- **II – Produced Water & Brine**
- **III – Acid Gas (CO_2 & H_2S)**
  – Hydrocarbons/Other Gas
- **IV – Non-Saline Water.**
  – Steam for Thermal Operations re: In-Situ Bitumen in Oil Sands Areas
  – Definition in Water Act (4,000 mg/l TDS, anions, bicarbonate, Na, Cl, K).

D51: Common to All Wells

- **Zonal Isolation: Need Hydraulic Isolation of Zone.**

Can be confirmed with a combination of the following requirements (under revision) depending on the type and the age of the well

- **Initial pressure test of casing & packer to a 15-minute stabilized pressure of the greater of:**
  - **7000 kPa for 15 minutes or,**
  - **maximum approved wellhead injection pressure;**
- **Tubing & casing grade & weight appropriate for fluid/gas injection (in-situ steaming at much higher T,P conditions);**
- **Packer Initial logging requirements;**
- **Cement integrity log (depends whether acid gas or conventional);**
- **Hydraulic isolation log;**
- **Casing integrity log.**

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D51: Under Revision & Review

Specific Considerations For CO2 Injection

➢ Application Requirements:

– Show cement and casing will provide long term containment;
  – Use low permeability cement over injection formation;
  – Use appropriate casing;
  – Must have two master valves on wellhead.

➢ Casing & Cementing:

– Surface casing must be set to base of groundwater protection;

– Must show good cement on surface casing & next casing string;

– No remedial cementing allowed.

➢ Casing Integrity Log:

– After surface casing is set, an initial cement integrity log must be run on the next casing string.

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D51: Under Revision & Review

Specific Considerations For CO2 Injection

- **Cement Integrity &Hydraulic Isolation Logs:**

Run cement integrity log plus one of these for hydraulic isolation

– Radioactive tracer;

– Cased hole neutron (capable of detecting gas movement);

– Temperature log;

– Oxygen activation log.

- **Some Considerations Monitoring & Reporting**

– Continuous annular Pressure & WHIP;

– Annual packer isolation to 7 m Pa (at surface) or 1.3 x wellhead injection pressure for 15 minutes;

– Hydraulic isolation log every 5 years;

– Casing integrity log every 10 yrs;

– Subsurface safety valves tested semi-annually;

– All information retained for the life of the well.

Summary Proposal Not to Industry/Board Yet

Wellbore Design		Logging Requirements		Minimum Reporting / Monitoring Program
Surface Casing to	Cementing Requirement	Hydraulic Isolation	Casing Integrity	
BGWP	SC - cement returns to surface; Next casing string - cement returns to surface.	Cement integrity log and one of the following hydraulic isolation logs: - temperature; - radioactive; - cased hole neutron log; - any approved log capable of detecting gas movement.	Casing integrity log No casing patches or liners allowed	-Continuous monitoring and recording of annular pressure; -Continuous monitoring and recording of WHIP; -Annual packer isolation test; -Hydraulic isolation logging every 5 years; - Casing integrity logging every 10 years

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ERCB vs EPA Proposed Class for New CO_2 Injection Wells

	ERCB (Source: ERCB Proposed Directive)	EPA (Source – EPA Proposed Rule 40 CFR Parts 144 & 146)
Surface Casing Surface & 2nd casing	Set through base of lowest USDW Cement to surface	Set through base of lowest USDW Cement to surface
Packer	Opposite cement and within 15 m of perfed interval	Opposite cemented interval
Cement	Cement appropriate for type of injection fluid	
Pipe Metallurgy	Appropriate for the type of fluid injected	High strength steel alloy or fiberglass
Monitoring	•Continuous monitoring of WHIP and annular pressure	•Continuous monitoring of injection pressure, flow rate, volumes, mechanical integrity •Downhole auto shut-off •Corrosion monitoring •Position of CO2 plume and pressure front [1] •Groundwater quality and geochemical changes [1]

1 Addressed in ERCB scheme approval conditions

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ERCB Well Integrity Directives

- **Dir 51 – Wellbore Injection Requirements**
  - **Dir 08 – Surface Casing Min. Depth**
  - **Dir 09 – Casing Cementing**
  - **Dir 10 – Min. Casing Design**
- **Dir 36 - Drilling Blowout Prevention**
  - **Dir 20 – Well Abandonment**

Details can be found at:
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Select <Industry zone>; <Rules,Regulations…>; <Directives>

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D08 Surface Casing Depth

➢ Two Main Purposes for Surface Casing:

– Well control;

– Protection of Groundwater (BGWP) non-saline water (i.e. water containing < 4000 mg/l total dissolved solids).

D09 Casing Cementing

– Applies to conductor pipe; surface production, intermediate and liner casings;

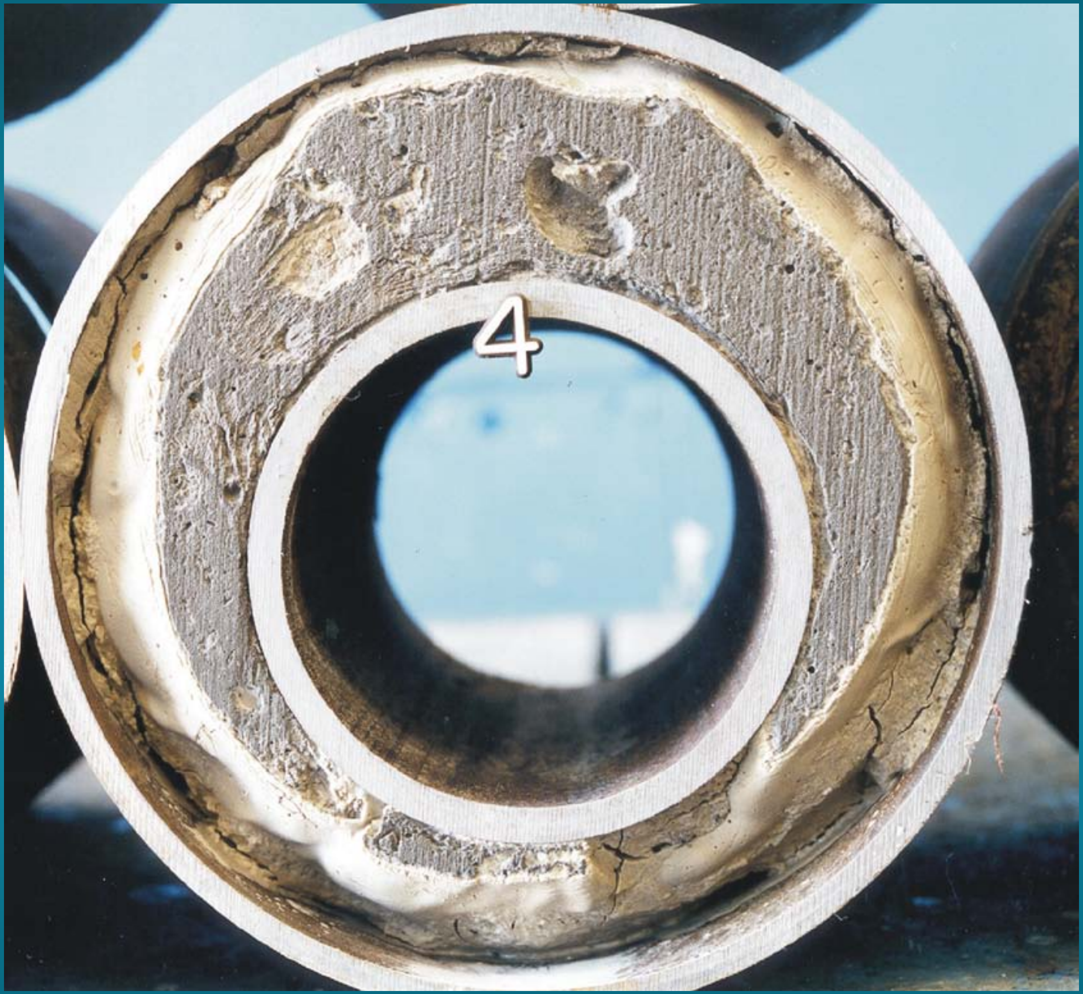
– Addresses cement top, application method, volumes, fillers/additives, temperature, record keeping.

➢ Cement Type & Placement:

– Higher cement porosity & permeability may contribute to cement degradation due to CO2;

– Cementing problems such as channeling, micro annuli, poor centralization or poor filter cake/ mud removal will lead to loss of integrity.

Cement with Poor Mud Displacement



Watson, T.L., Getzlaf, D., and Griffith, J.E., Specialized Cement Design and Placement Procedures Prove Successful for Mitigating Casing vent Flows—Case Histories; SPE 76333, Calgary AB, Canada, May 2002.

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D10 Minimum Casing Design

– Applies to surface, production, and intermediate casing as well as liners;

– Addresses design factors associated with:

Minimum burst-pressures & collapse-pressures;

Minimum tensile strength (tension).

D10 Minimum Casing Design (Updated 12_2009)

– To address sulphide stress cracking concerns, upgraded design factors & material specs now incorporate NACE MR0175/ International Association for Standardization (ISO) 15156. Also:

– Compliance and enforcement;

– Detailed design and metallurgy criteria for sweet, sour, and critically sour wells;

– Casing requirements for re-entry wells;

– Casing wear considerations;

– Design criteria for burst strength, body yield strength & tension;

– Design burst loads using assumed /calculated gas gradient.

D20 - Well Abandonment (Being Updated)

- Cover all non-saline (> 4,000 mg/l TDS) ground-water & isolate or cover all porous zones.
  - Addresses minimum requirements for abandonments, casing removal, zonal abandonments and plug backs.
- Well abandonment requirements need to become more stringent to ensure that CO2, EOR and CO2 storage is viable in the future;
- All wells, not just ones think in the project;
- Combination of hole conditioning prior to open hole abandonment & incorporate the best of the regulation.

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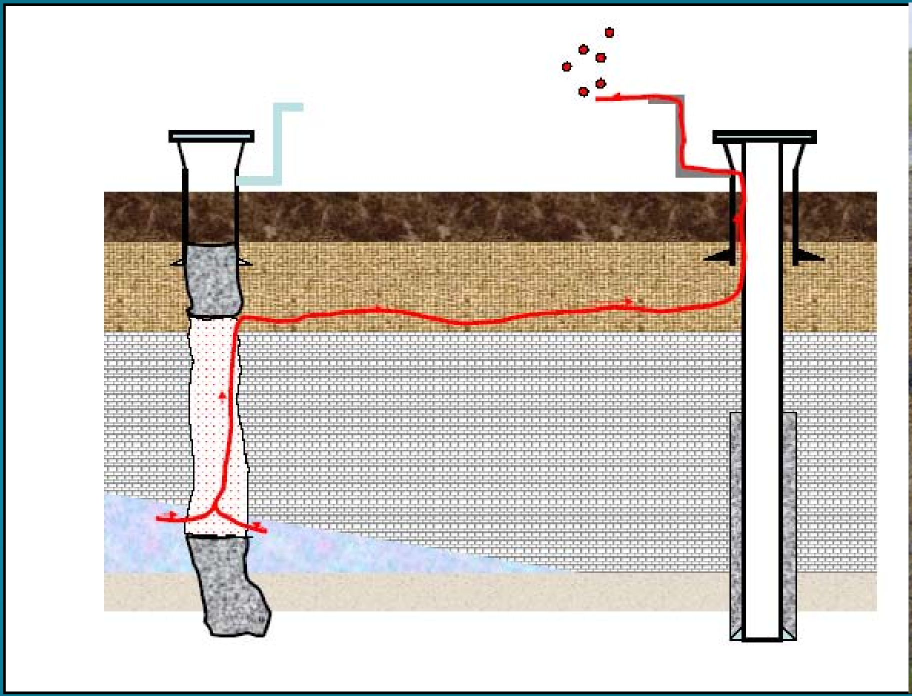
Low Abandonment Plug Can Lead to Cross-Flow

Result of Subsurface Cross-Flow



Watson, T.L., 2009. CO2 Storage: Wellbore Integrity Evaluation and Integrity across the Caprock; SPE 126292, Presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, USA, 2-4 Nov, 2009.

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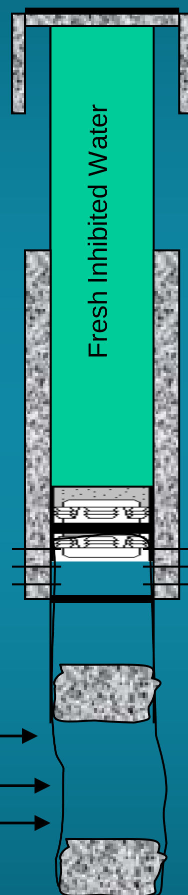
Abandoned Well: Sequestration Zone Exposed

CO2 or Increased Pressure Cross-Flow

Spud 1956-05-30
Abandoned 1996-07-04

Ground Water Protection Depth
300.8 mKB



2 sack cement plug

Surface Casing: 323.85 mm open hole. Ran 244.5 mm casing and landed at **187.5** mKB. No cement information available.

Cement Top Unknown

Production Casing: 200 mm open hole. Ran 79 jts, 139.7 mm, 20.83 kg/m, J-55, landed at **783** mKB. No cement information available.

Bridge plug at **752** mKB capped with 8 m cement.

Perforations **758.6-759.9** mKB

No Cement Plug in Ireton

Cement plug **1009-1041**mKB
35 sacks, tagged

Porous Zone- **1047.90** mKB

Cap Rock- **1087.20** mKB

Sequestration Zone- **1112.20** mKB

200 mm Open Hole

Cement plug **1120.14-1129.28** mKB
45 sacks

TD 1129.28 mKB

Need to Look at Zone of Influence. How Far Out Do We Have To Go?

Watson, T.L., 2009. CO2 Storage: Wellbore Integrity Evaluation and Integrity across the Caprock; SPE 126292, Presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, USA, 2-4 Nov, 2009.

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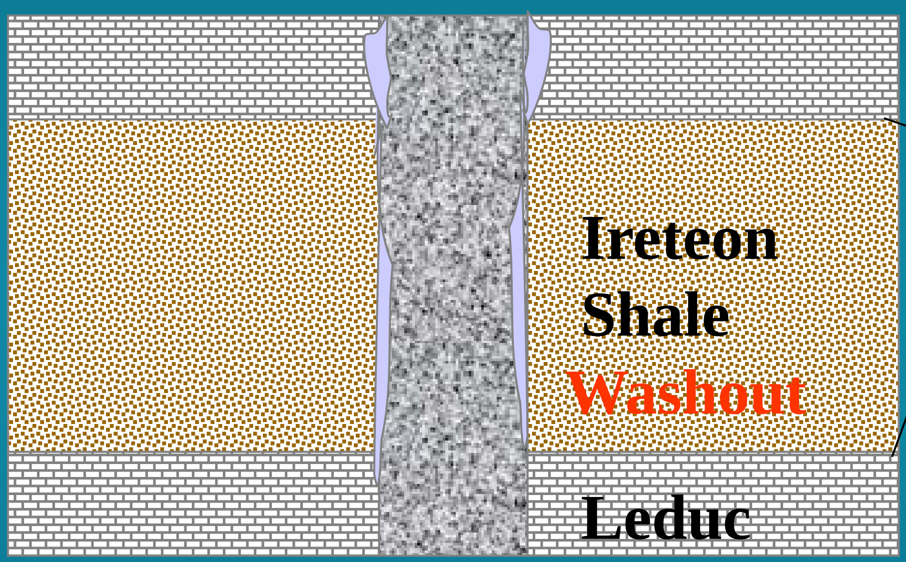
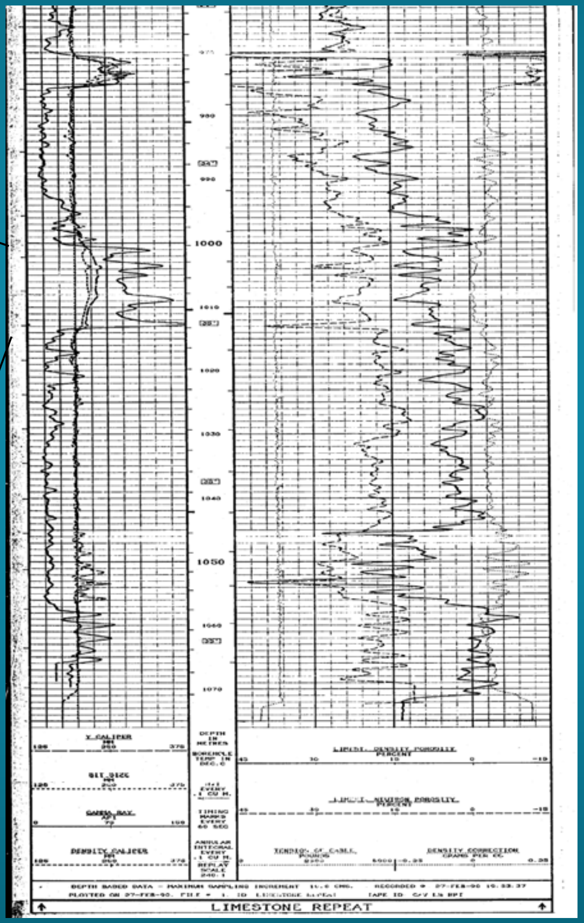
Open Hole Abandonment Challenges & Evaluation

Exacerbated if increased Pressure due to CO2 Injection (Ex: Redwater)





Depiction of cement plug with filtercake and washout

Watson, T.L., 2009. CO2 Storage: Wellbore Integrity Evaluation and Integrity across the Caprock; SPE 126292, Presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, USA, 2-4 Nov, 2009.

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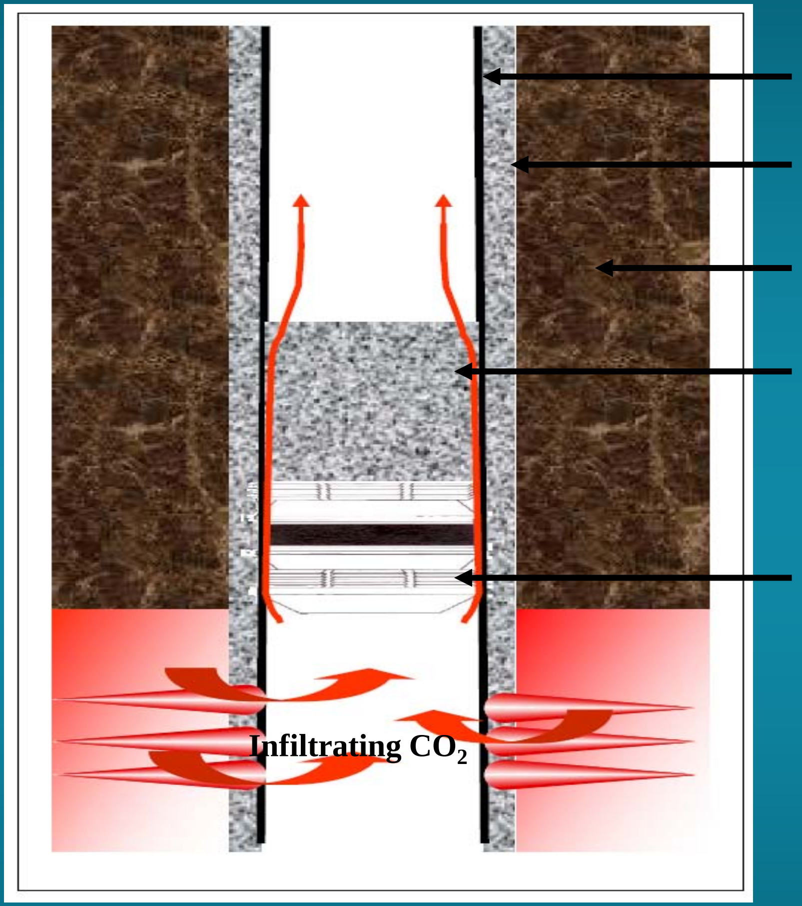
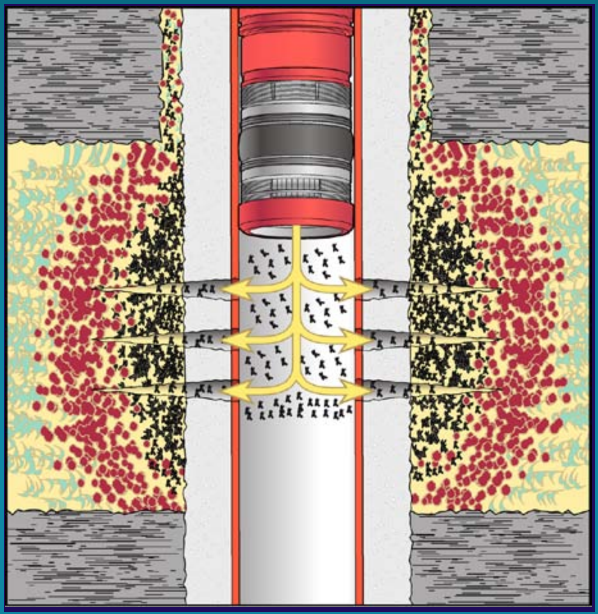
Improve Cased Hole Abandonment Techniques



Current Abandoned Wells



Need to Protect Future Modes of Operation (In Consultation)

Watson, T., Bachu, S., Identification of Wells with High CO2-Leakage in Mature Oil Fields Developed for CO2 Enhanced Oil Recovery. SPE 112924 Tulsa, OK, 19-23 April 2008

Remediation & New Well Designs

- **Abandoned Wells**
  - This is going to require a lot of money where wells are identified as problematic, in particular for open hole abandonments;
  - Section milling and squeezing at the zone/caprock interfaces;
  - New products such as ceramic cements and metal alloys may have good application
- **New Wells Design/Considerations**
  - Deviation of wells through the caprock;
  - Details of cementing, including: centralization, hole conditioning, mud condition, filter cake removal;
  - Cement design for low permeability/porosity;
  - Dead Legs.

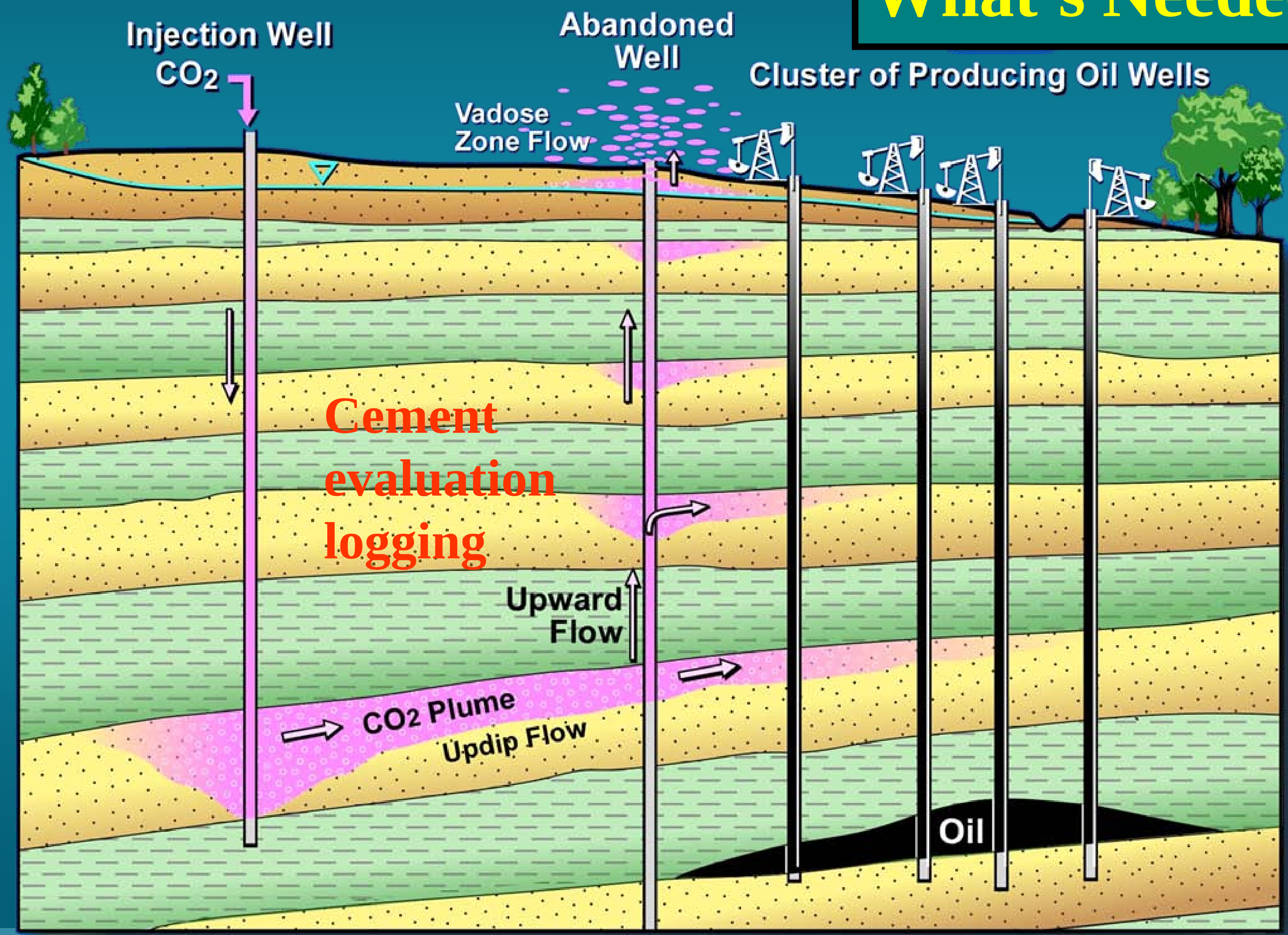
Watson, T.L., 2009. CO2 Storage: Wellbore Integrity Evaluation and Integrity across the Caprock; SPE 126292, Presented at the SPE International Conference on CO2 Capture, Storage and Utilization, San Diego, California, USA, 2-4 Nov, 2009.

What's Needed?

Casing inspection for external needs

Open hole evaluation of plugging techniques

Cement evaluation logging



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Other Future Concerns

Horizontal Drilling in Organic Shales: Multifracs. Would This Be Caprock Integrity Loss to Other Producing Conventional Fields and also to potential CO2 Sequestration Sites?

Questions & Discussion ???

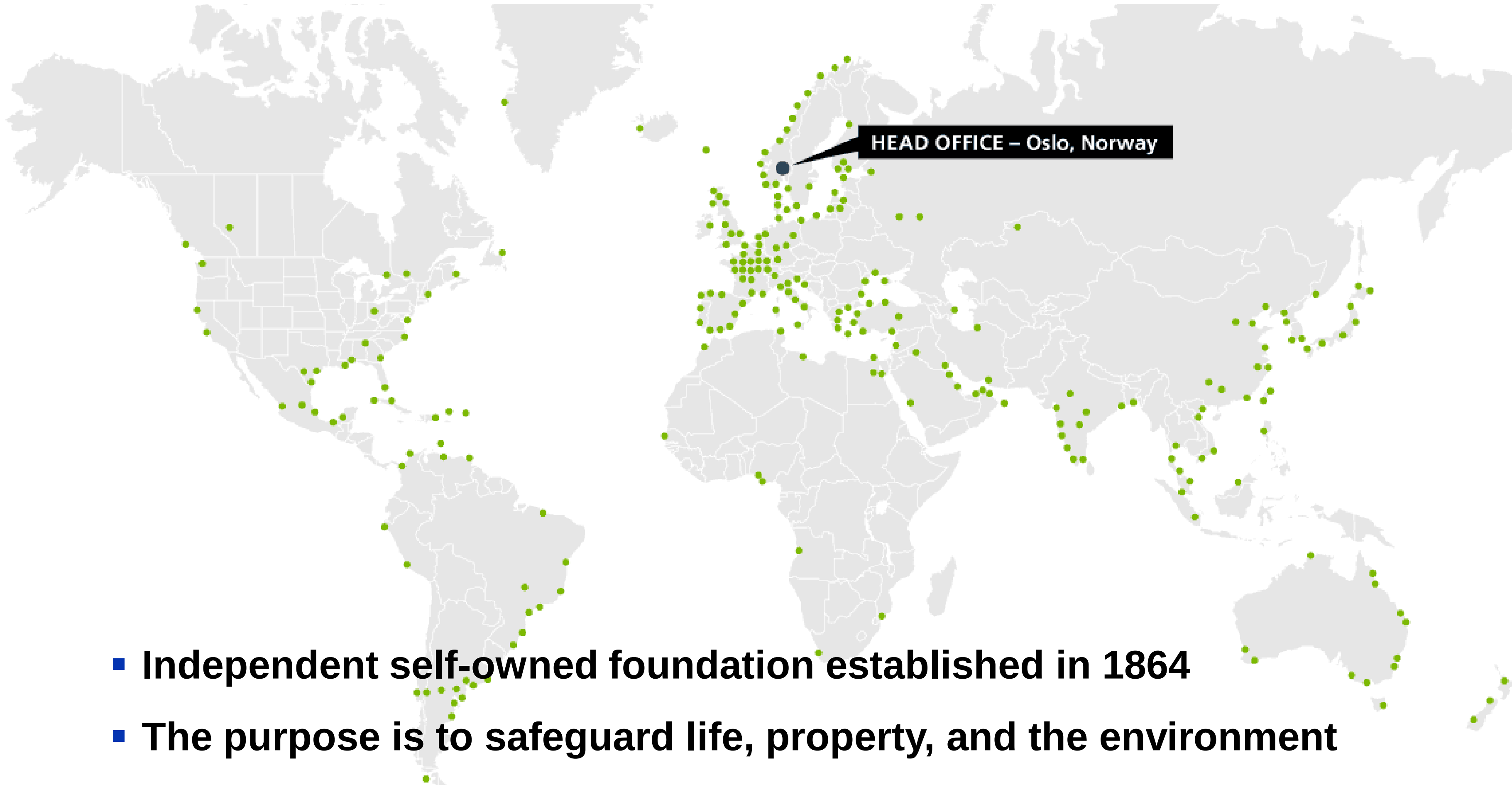
The CO2WELLS Joint Industry Project

- an opportunity to demonstrate industry know-how

Mike Carpenter
April 28, 2010

MANAGING RISK DNV

DNV



- **Independent self-owned foundation established in 1864**
- **The purpose is to safeguard life, property, and the environment**
- **Use profits to continuously develop our people and innovation**

Core competence

Industry:

- Energy sector – **CCS,** oil & gas, nuclear, renewables
- Maritime sector – DNV Class, design, logisitics
- Identify, assess and manage risks in their operations

Society:

- Technology development and knowledge sharing increase innovation and safety
- **Joint industry projects are key to obtaining reliable guidelines and standards**
- They allow industry players and authorities to join forces
- DNV's in-depth knowledge and independent role facilitate this process
- 30-40 such projects launched each year

MANAGING RISK

Decision support

Political decision to fund CCS?

Climate change • **Y/N**

- Cost
- Public opposition
- CO_2 leakage

Technical regulatory bodies

USA | Canada | UK | Australia | Germany | Norway | China

cementing | casing | operations | abandonment | etc...

Standards

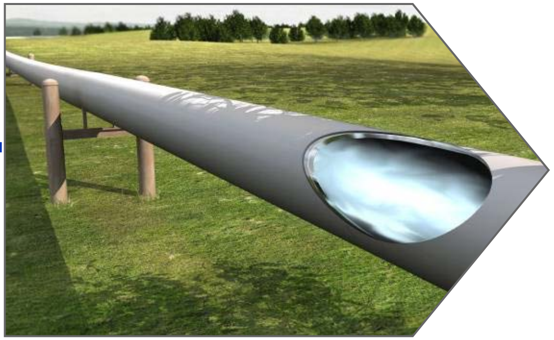
Propriety manuals & technology

Technical novelties in the CCS value chain

Capture

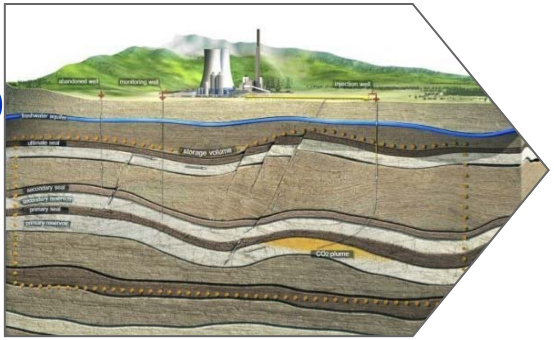
- Fossil power plants
- Natural Gas CO_2 reduction
- Other industrial processes

Transport



- Pipelines
- Ships

Storage



- Depleted oil or gas reservoirs
- Saline aquifers
- Enhanced Oil Recovery (EOR)

- Introduction of new technologies
- Up-scaling
- Accidental discharge and dispersion

- Corrosion
- Material selection and structural integrity
- Flow assurance and operational issues

- Qualification of sites
- Monitoring and verification
- Permanence of storage
- Long-timeframe well integrity

INTEGRATION

Technical novelties in the CCS value chain

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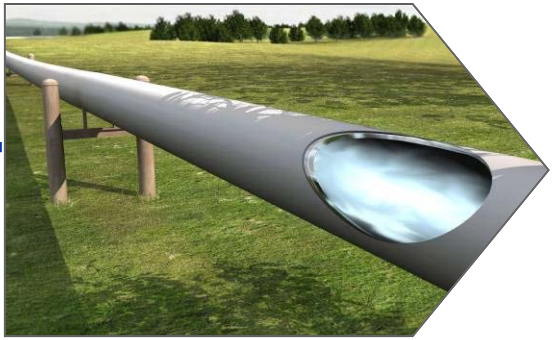
- Natural Gas CO_2 reduction
- Other industrial processes

Transport



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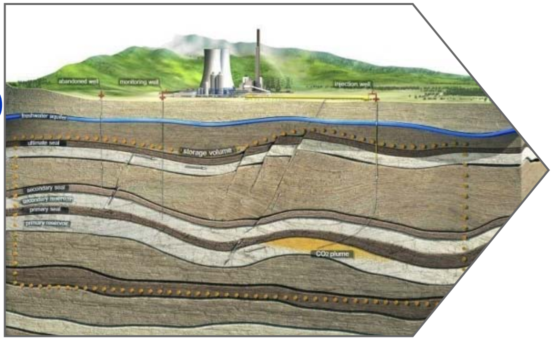

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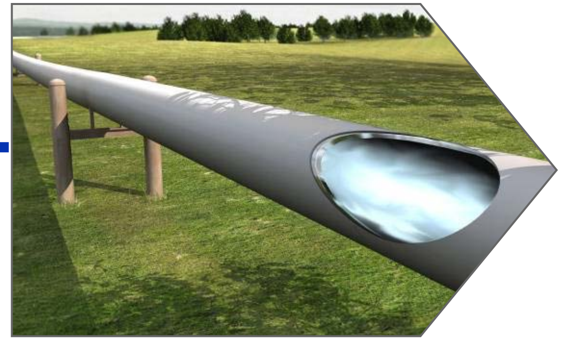

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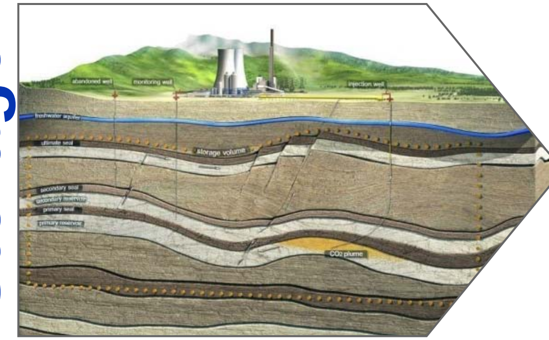

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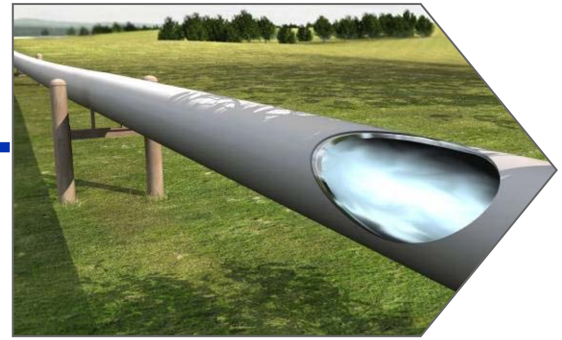

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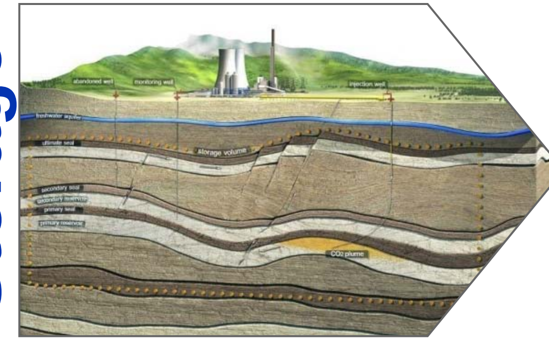

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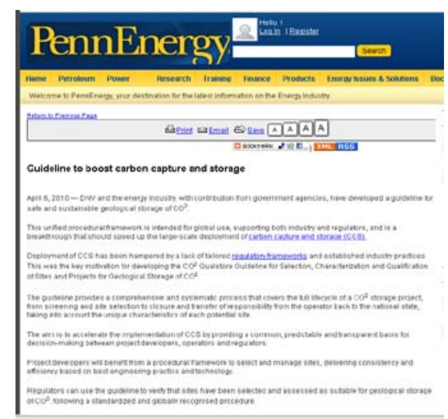
INTEGRATION

Vision: a guideline that builds on the success of CO2QUALSTORE

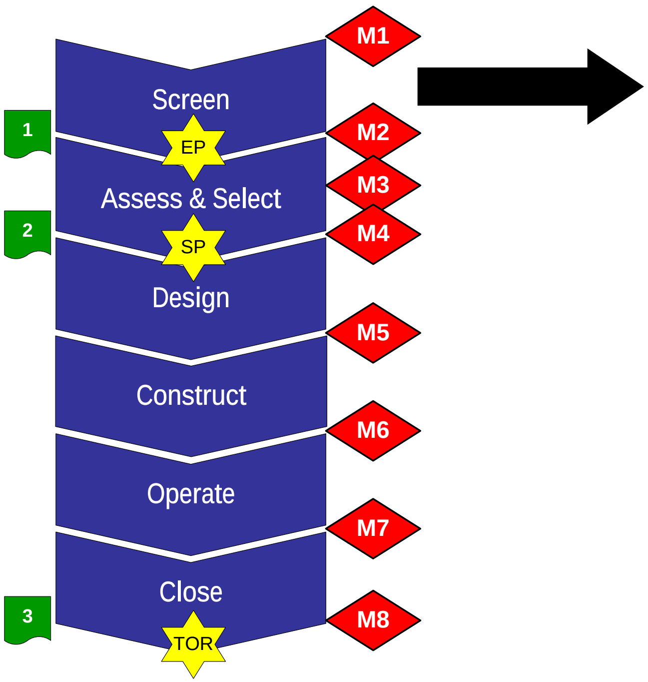
Partners

- The CO2QUALSTORE guideline was published in April 2010 and provides guidance on the selection and qualification of onshore and offshore CO2 storage sites.

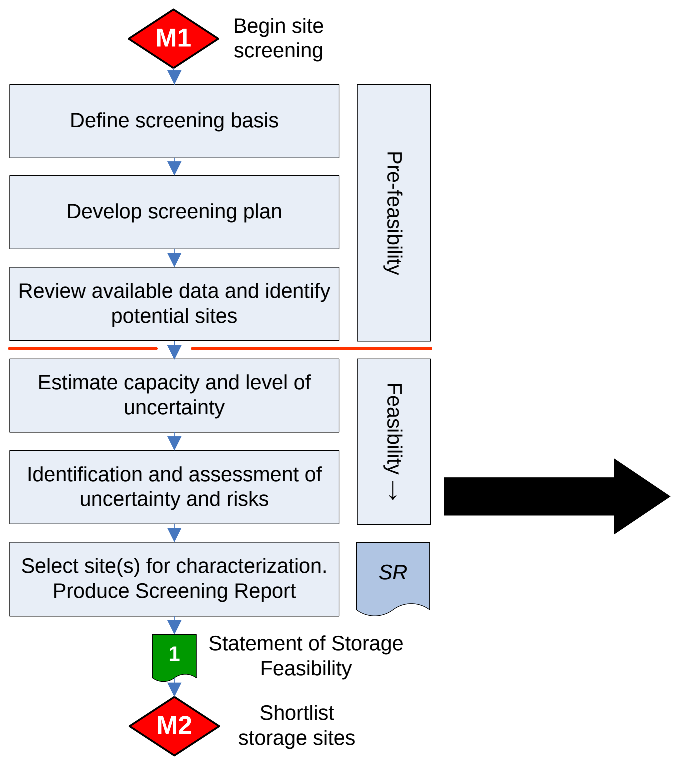


Press coverage in April 2010 for the publication of the CO2QUALSTORE guideline. See www.dnv.com/co2qualstore

CO2QUALSTORE guideline and well integrity



CO2QUALSTORE stages



Screen stage workflow

Typical questions related to wells:

- **How many?**
- **Abandoned?**
- **Active?**
- **Condition?**
- **Records?**
- **Age?**
- **Safeguards?**

MANAGING RISK

A comprehensive CO_2 wells guideline is required

Objectives:

- Develop framework for **risk assessment** of all types of wells at CO_2 storage sites
- Develop a procedure for **re-qualification** of wells for CO_2 injection
- Apply methodology to real life **case studies** and evaluate how guideline may help demonstrate compliance with regulatory requirements

The lack of a recognized framework for risk evaluation of abandoned wells currently poses a barrier to cost-efficient implementation of CCS in regions that have been subject to O&G activities

A comprehensive CO_2 wells guideline is required

- CO_2 injection is not new
- …but the political and legislative demands around CO_2 storage are new
- The transfer of liability issue puts new demands on transparency and information management.

This guideline provides:

1. an opportunity to demonstrate industry know-how
2. a technical, performance based approach
3. a chance for leading industry players to set the standard

- *Note: there is no expectation of sharing proprietary technology – this is about showing what works to a wider audience*

CO2WELLS guideline will be in two parts

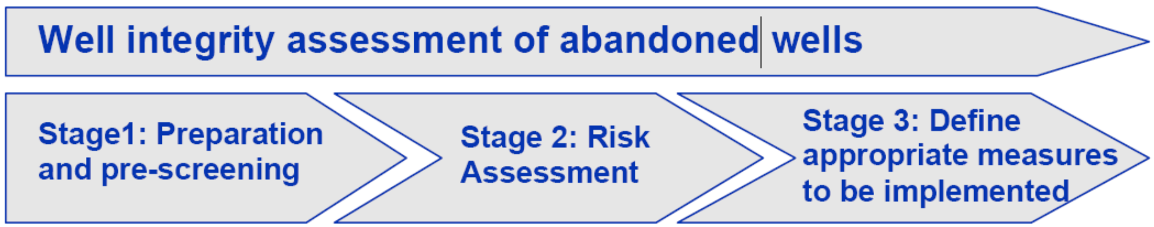
- **Guideline part A**
- Risk management of abandoned and active wells
- Establish a basis for a common industry approach based on industrial experience and scientific knowledge that serve as a basis for proper risk management

- **Guideline part B**
- Re-qualification of existing well infrastructure for CO_2 injection
- Provide a recognized approach to re-qualification of wells for CO_2 injection based on industrial procedures for technology qualification

Final guideline will provide a systematic approach to managing all the risks associated with new and exisiting wells at a CO_2 storage site (onshore + offshore)

Preliminary framework for part A

- DNV has developed a risk assessment methodology for abandoned wells that can be used to rank prospective CO_2 storage sites at an early stage:



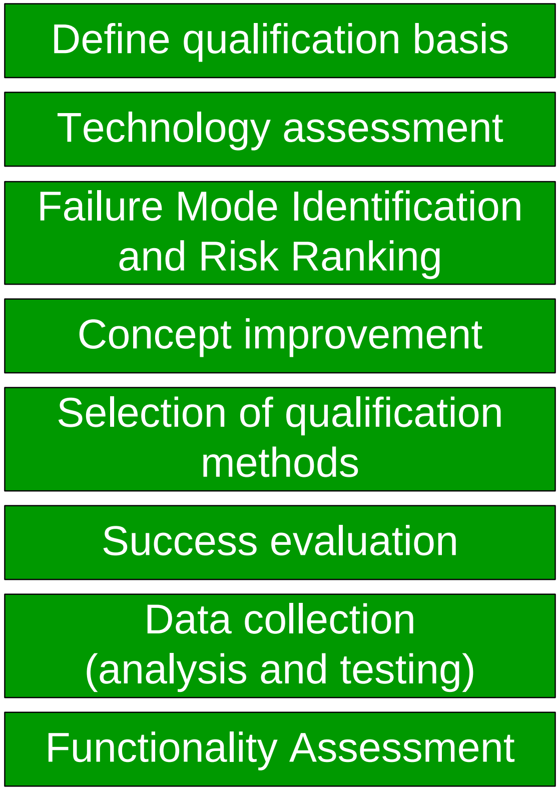
1) Categoize wells according to their need for further risk assessment (e.g. number and quality of known leakage barriers)

2) Perform a risk assessment to evaluate the integrity of abandoned wells. Produce a well register containing all risk elements considered relevant for each well and the level of their criticality.

3) Identify safeguards that can reduce the risk or uncertainty associated with specific wells.

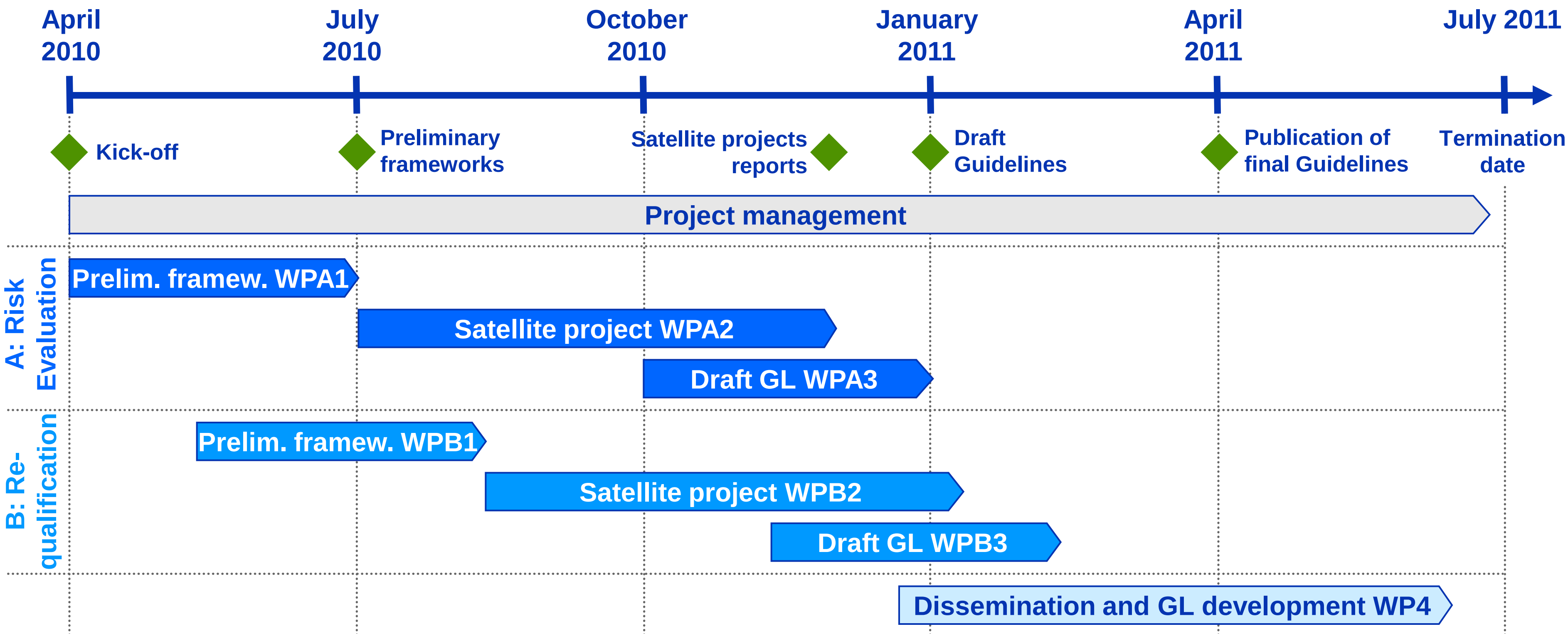
Preliminary framework for part B

- DNV proposes to develop a specific well re-qualification method based on technology qualification methodology DNV RP-A203
- The well re-qualification method will be applicable to:
  - well design
  - condition assessment
  - operation
  - contingency planning
- Industry experience shows that injection wells are more prone to failure than production wells
- Potential failure modes include fracturing of the cement-formation interface and corrosion of tubing and casing.



Flow chart for Technology Qualification from DNV RP-A203

Schedule



1. April – July 2010	Develop preliminary frameworks for parts A & B
2. July – Nov 2010	Industry case studies (USA, Canada, Europe, Australia)
3. Q1 2011	Publish final guideline

Who has joined so far?

<u>Operators (fee: 400,000NOK):</u>

- National Grid
- RWE Dea
- Vattenfall
- E.On Engineering
- Gassnova
- Gassco

Expressions of interest from:

- UK Health and Safety Executive
- Petrobras

<u>Regulators (free as observers):</u>

- UK Department of Climate Change
- UK Marine Management Organisation
- UK Crown Estate

Expressions of interest from:

- Australia Department of Resources, Energy and Tourism
- Alberta Energy Resources and Conservation Board
- Energy Resources, Danish Energy Agency
- State Supervision of Mines, Netherlands

Deadline for late participants is 8 July 2010.

Mutually beneficial collaboration with network

Benefits for this network:

- Formalise findings in a guideline
- See research results applied
- Take part in workshops
- Contribute to international industry/regulator dialogue

Benefits for the guideline:

- Coordination with other intiatives
- Complimentary scope of work - not overlapping
- Rigorous peer review of guideline
- Better uptake

Invitation to to join this project

1. The steering committee is open for new members. Their aim is to produce an industry guideline in dialogue with regulators.
2. Experienced operators can contribute to the common good of the industry, speeding up development and increasing the chance of a successful beginning to CO_2 storage.
3. This JIP will produce a guideline in 2011. As an operator or regulator you can collaborate in this process and have a say on what the guideline will propose as best practice.

Safeguarding life, property and the environment

www.dnv.com

MANAGING RISK DNV

Schlumberger
Carbon Services

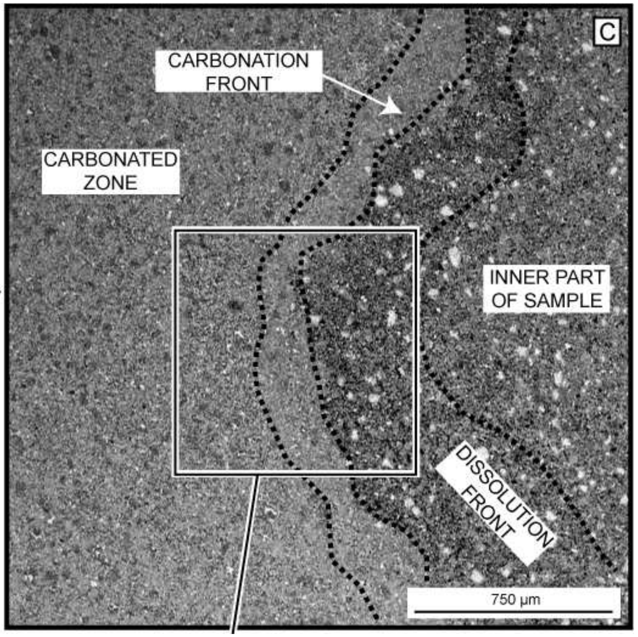
Investigating the Evolution of Cement Mechanical Properties in CO_2 Injection Wells and its Potential Effects on Well Integrity

Brice Lecampion, Daniel Quesada, Bruno Huet

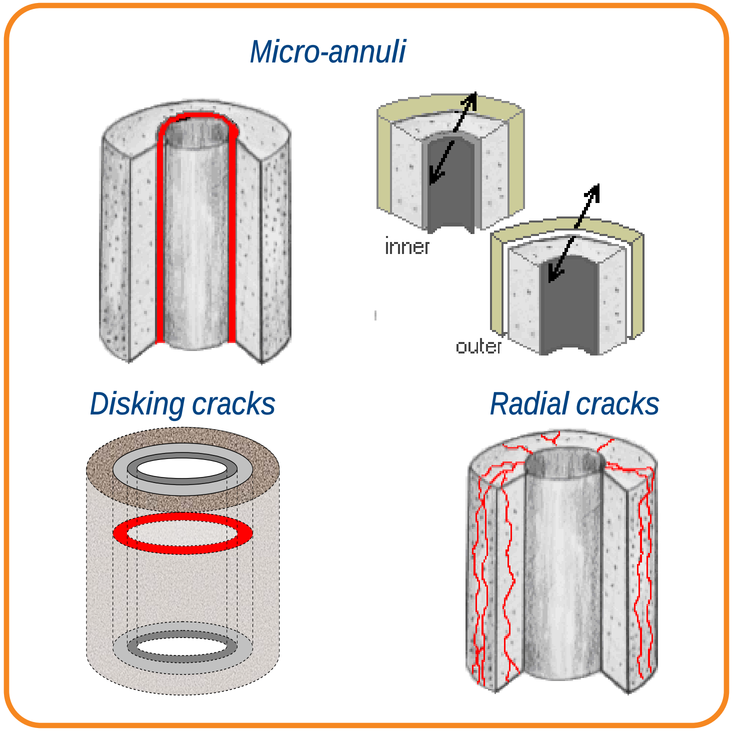
Motivations

Schlumberger Carbon Services

- The cement sheath of a cased and cemented well is known to be a common locus of leakage pathways.
- Class G cement is a heterogeneous material, even more so when carbonation occurs…
  Is carbonation benefic or detrimental for the well integrity ?
  Will the carbonated zone be more prone to failure ?



Taken from Rimmelé et al., 2006

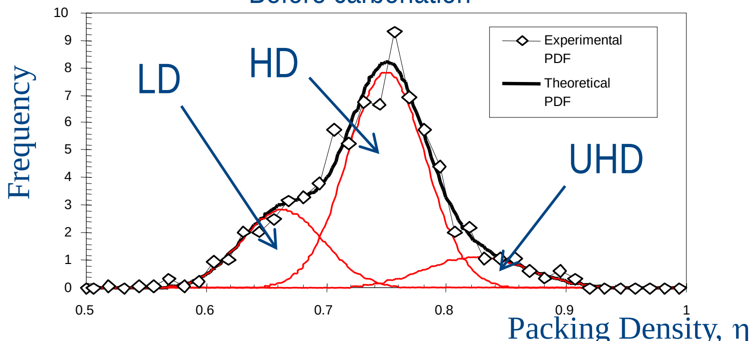


Main fracture layouts observed in cement sheaths

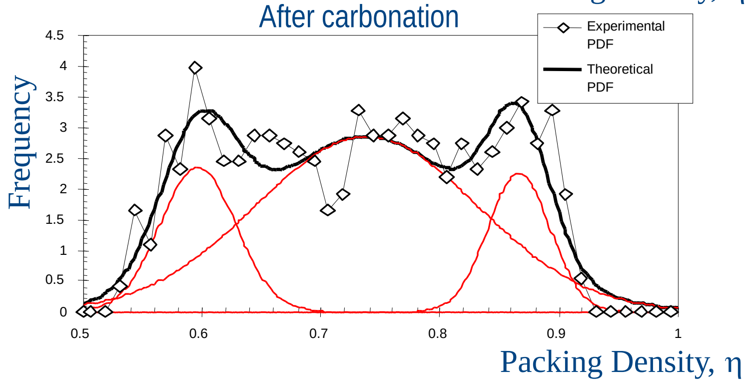
Experimental investigation: CSH matrix

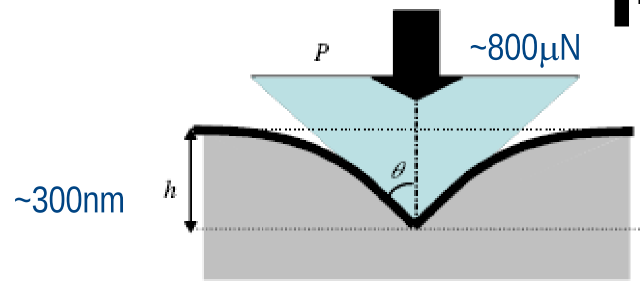
- Nano-Indentation grid, statistical deconvolution of the results [Ulm et al., 2004-2007]
  - Intrinsic properties of CSH “globule “
  - Low-Density & High Density Packing
- EPMA grid & statistical analysis

Before carbonation



After carbonation



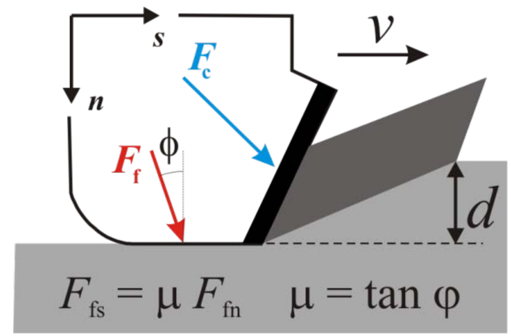


Vanzo and Ulm, 2009 (MIT CEE R09-01)

- CSH matrix in the un-degraded part is similar to the non-carbonated samples
- Carbonated matrix
  - Calcium Carbonate (1.5µm)- Decalcified CSH (Ca/Si=0.8) – Silica gel (10-20µm)
  - Highly disordered
- Carbonation depletes portlandite prior to attacking the C-S-H

Experimental investigation: Macro-scale

Repetitive Scratch tests along the axial length of the core: going toward the center of the core



[Detournay & Defourny, 1992]

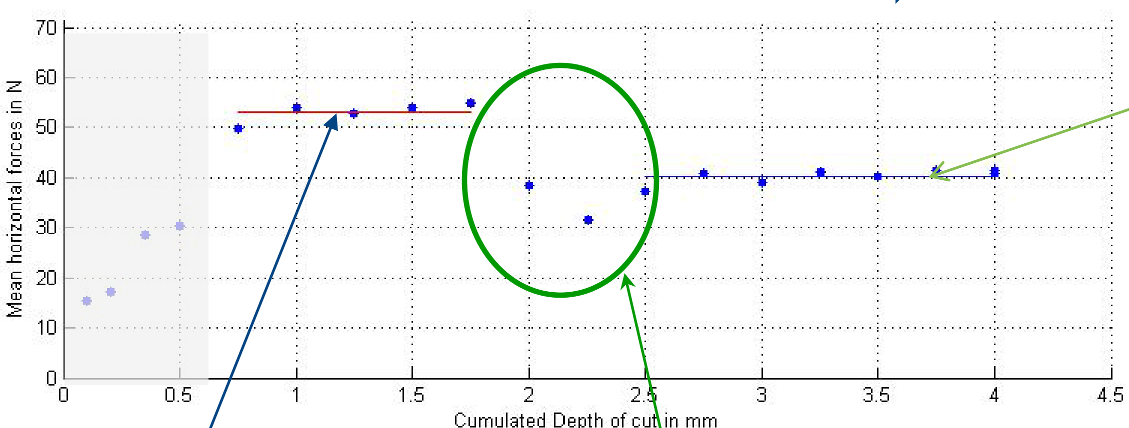
d ~ 0.1/0.25mm

w: 10/5/2.5mm

v ~ 1 cm/s

Evolution of mean Force as we scratch deeper in the carbonated cores (depth of each cut : 0.25mm)

Core Surface → Core Center



Un-degraded zone
ε=25.6MPa, UCS=42MPa

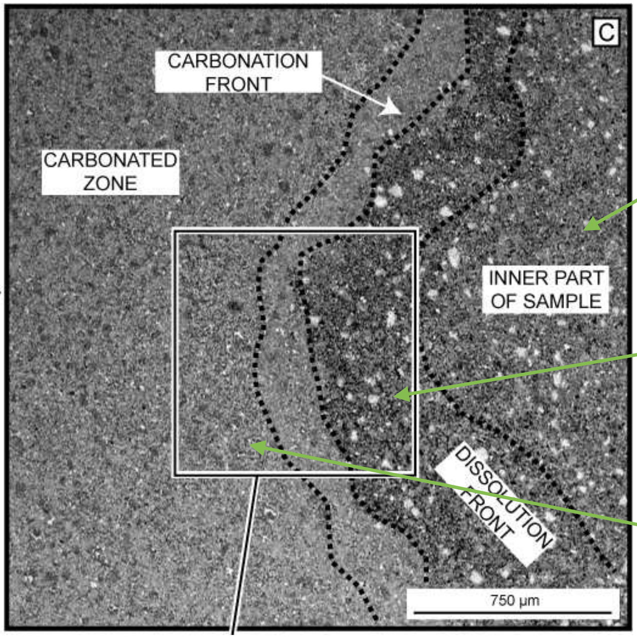
The center of the sample keeps the properties of the un-degraded material

Carbonated zone
ε = 35.06 MPa, UCS~57 MPa

Front

Material properties evolution: micromechanical estimates

Schlumberger Carbon Services



Taken from Rimmelé et al., 2006

Un-degraded material:

$$E = 21\,\text{GPa},\ \nu = 0.25,\ b = 0.66$$
$$V_p = 3690\ \text{m/s},\ V_s = 2020\ \text{m/s}$$

Match Ultrasonic measurements

Dissolution Front: CH replaced by pores

$$E = 12\ \text{GPa},\ \nu = 0.23,\ b = 0.84$$

Carbonated Zone:

Original CH replaced by Calcite (+11% volume increase)

From nano-indentation analysis :

Matrix as packing of Calcite & Decalcified CSH

$$E = 27\ \text{GPa},\ \nu = 0.26,\ b = 0.51$$

Ratio Carbonated / Uncarbonated :

Scratch

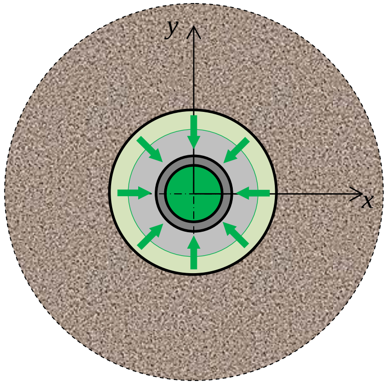
$$\frac{\varepsilon_{\text{carbo}}}{\varepsilon_0} = \frac{35.}{25.6} = 1.367$$

Up-scaling

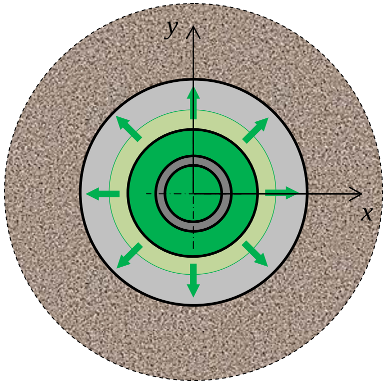
$$\frac{E_{\text{carbo}}}{E_0} = \frac{27}{21} = 1.283$$

Effect on Well Integrity

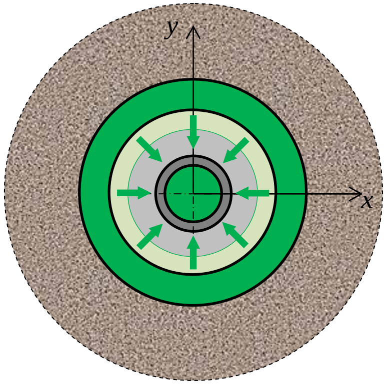
- Is carbonation detrimental or benefic for well integrity?
  - ➢ The dissolution front is a weak zone: can it become the locus of a new micro-annulus ? The answer probably depends on how carbonation occurs…
- Mechanical calculations performed on cross-sections perpendicular to well axis.
  - ➢ Tensile Failure (TF) and Mohr-Coulomb (shear) failure (MCF) conditions investigated for each component of the cement sheath (carbonated zone, dissolution front and uncarbonated/initial cement zone).
- Three critical carbonation scenarios (with different loadings) are investigated in the following:



Carbonation from formation (casing pressurized)



Carbonation from an inner micro-annulus (casing and micro-annulus pressurized)

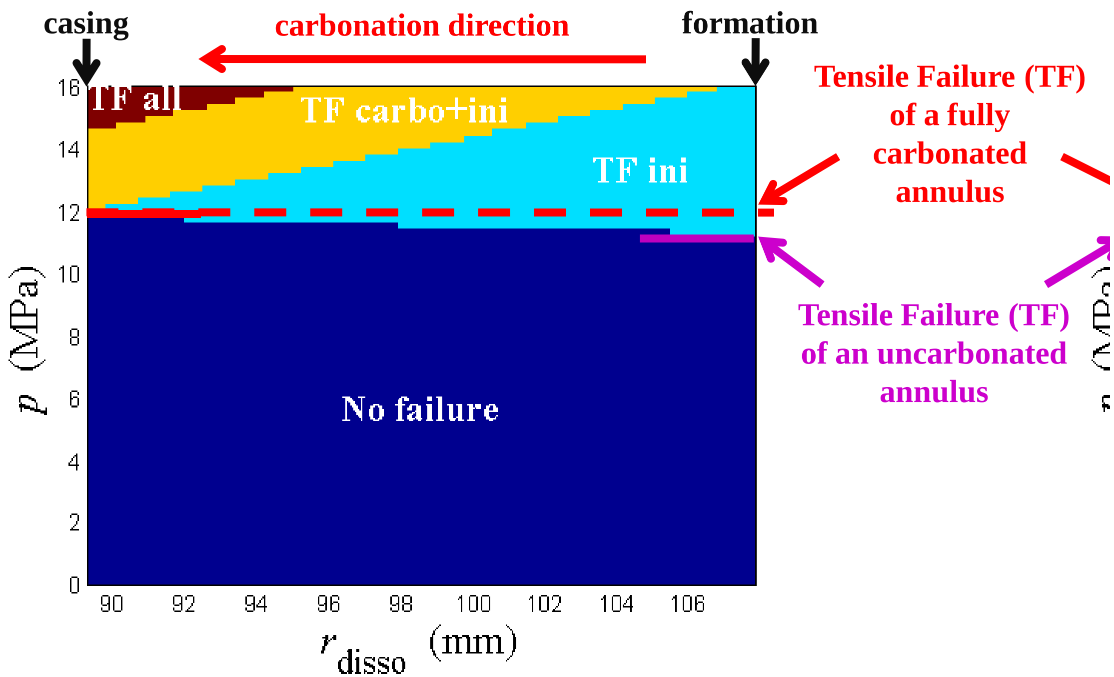


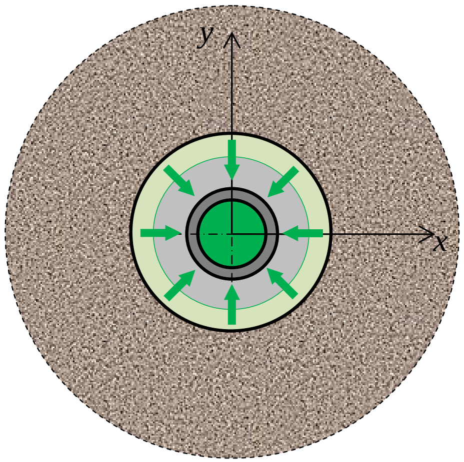
Carbonation from an outer micro-annulus (casing and micro-annulus pressurized)

Carbonation from the formation
Pressurization of the casing

Schlumberger Carbon Services

Dissolution front UCS = 25 MPa, TS=2.5 MPa





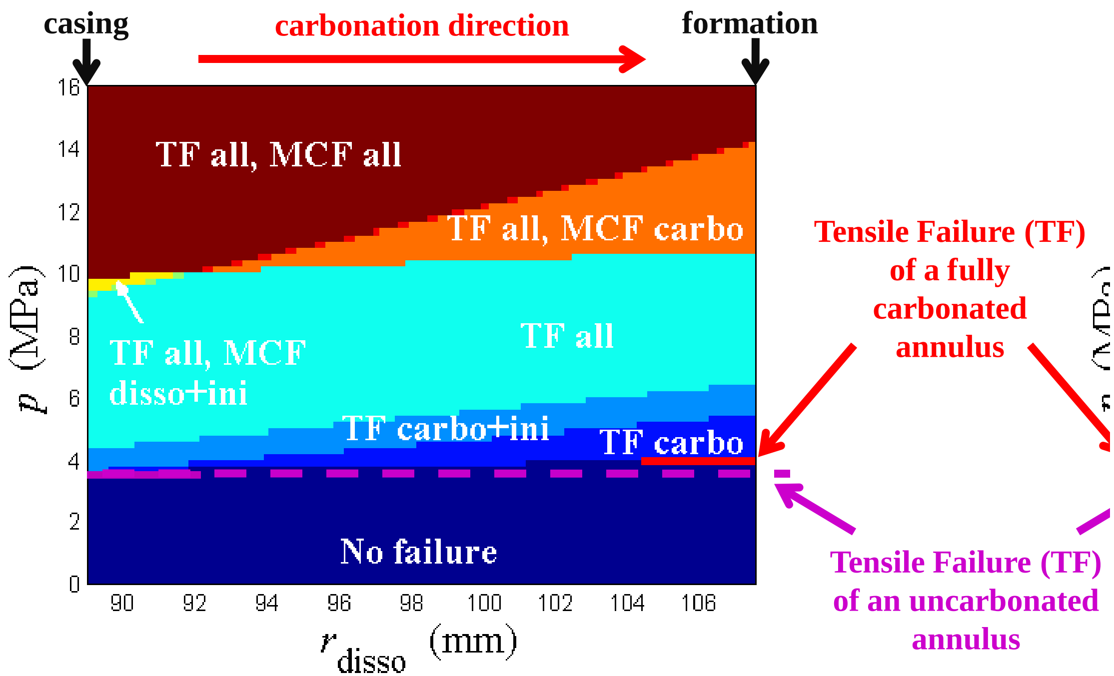
Carbonation from formation
(casing pressurized)

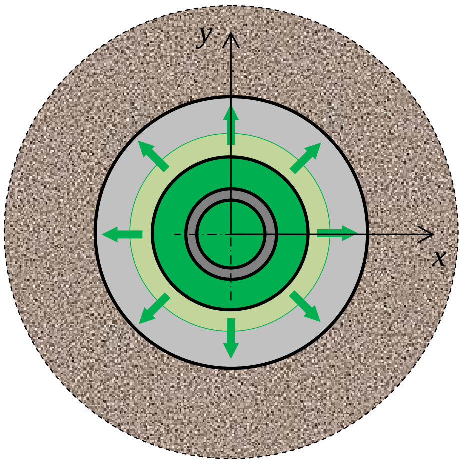
- Full carbonation: small effect on failure:
  fully carbonated vs. uncarbonated annuli: 5% increase of the failure load
- Partial carbonation:
  - For the **measured value of the dissolution front properties** (left), results are unchanged.
  - For **low failure properties of the dissolution front** (right), the partially carbonated annuli fails at the dissolution front, for one third to half the initial failure load.

Carbonation from an inner micro-annulus Pressurization of the micro-annulus

Schlumberger Carbon Services

Dissolution front UCS = 25 MPa, TS=2.5 MPa





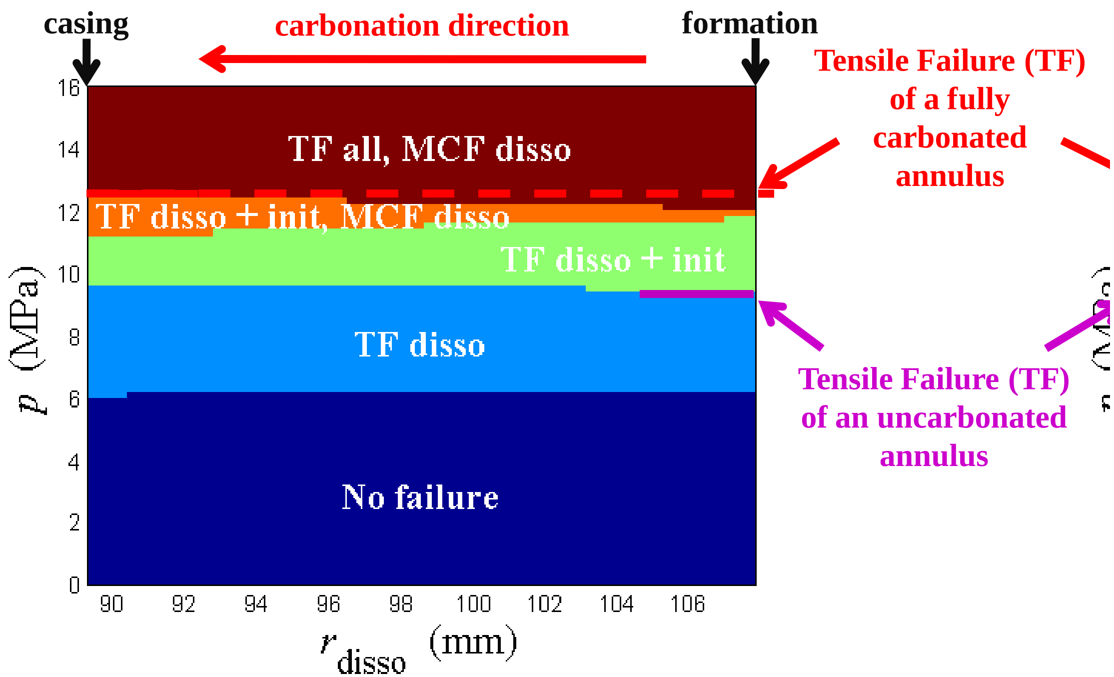
Carbonation from an inner micro-annulus (casing and micro-annulus pressurized)

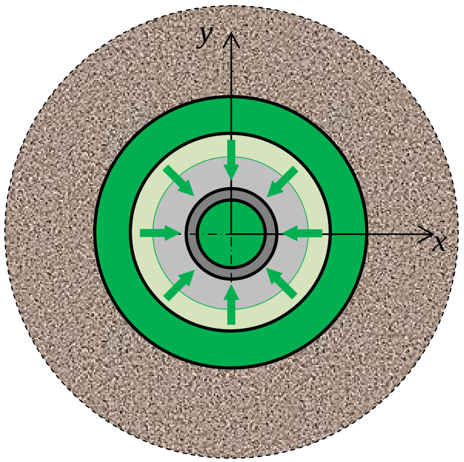
- Pressurizing a micro-annulus is detrimental (the failure load drops 70% compared to casing pressurization)!
- Full carbonation: small effect on failure (fully carbonated vs. uncarbonated annuli: 10% increase of the failure load).
- Partial carbonation:
  - For the measured value of the dissolution front properties (left), results are unchanged.
  - For low failure properties of the dissolution front (right), the partially carbonated annuli fails at the dissolution front, for one half to one third the initial failure load.

Carbonation from an outer micro-annulus
Pressurization of both casing and micro-annulus

Schlumberger
Carbon Services

Dissolution front UCS = 25 MPa, TS=2.5 MPa





Carbonation from an outer micro-annulus (casing and micro-annulus pressurized)

- **Full carbonation:** important effect on failure (fully carbonated vs. uncarbonated annuli: 34% increase of the failure load).
- **Partial carbonation:**
  - For the **measured dissolution front properties** (left), failure at the dissolution front. The failure load drops 37% compared to the uncarbonated case.
  - For **low dissolution front failure properties** (right), the partially carbonated annuli fails at the dissolution front. The failure load drops 70% compared to the uncarbonated case.

Conclusions

Schlumberger Carbon Services

- Understanding of cement carbonation & mechanical properties evolution at different scales being developed.
- Micro-annuli pressurization is strongly detrimental to mechanical integrity (inner & outer).
- Homogeneous (complete) carbonation effect:
  - Small in the case of carbonation from formation or from the inner micro-annulus.
  - Important in the case of the carbonation from the outer micro-annulus.
- Dissolution front further weaken the cement sheath. The strength of the dissolution front has a strong effect
  → needs to be better characterized.
- The same study needs to be done with respect to the thermal effects.

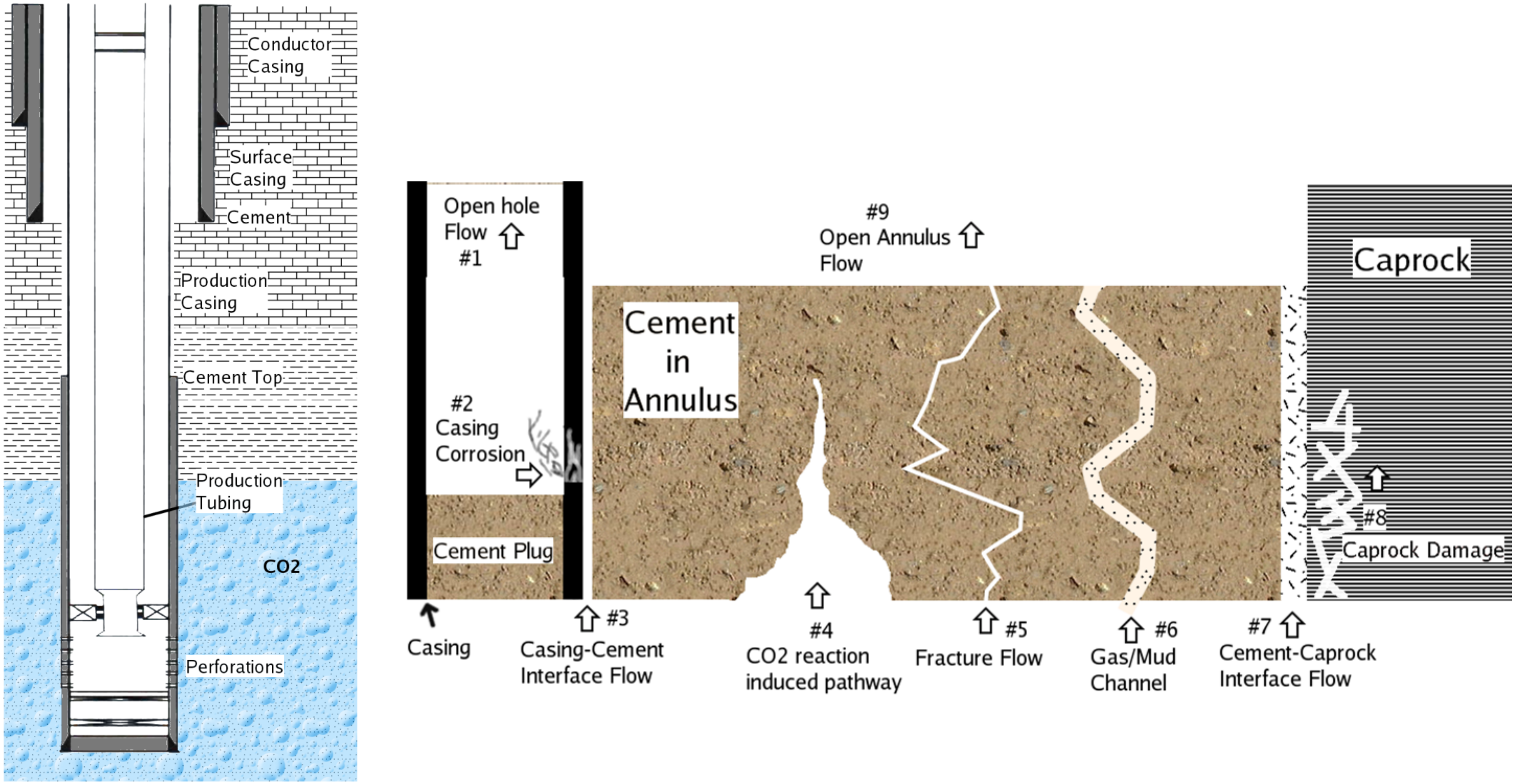
Assessing corrosion at the cement-steel interface in aqueous CO_2 environments

Jiabin Han and J. William Carey

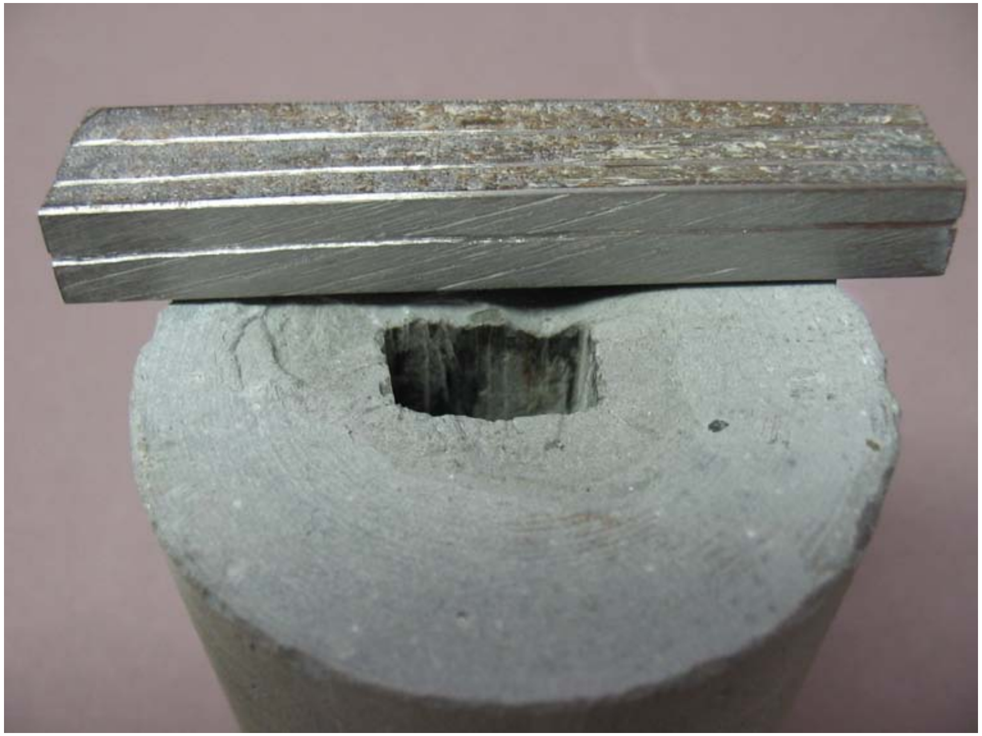
Los Alamos National Laboratory

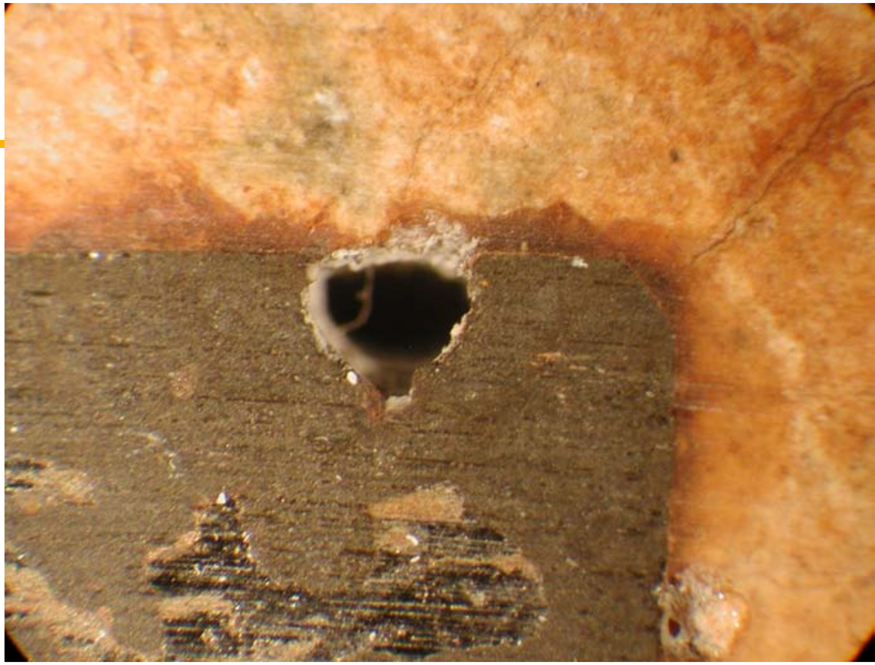
Los Alamos NATIONAL LABORATORY EST. 1943

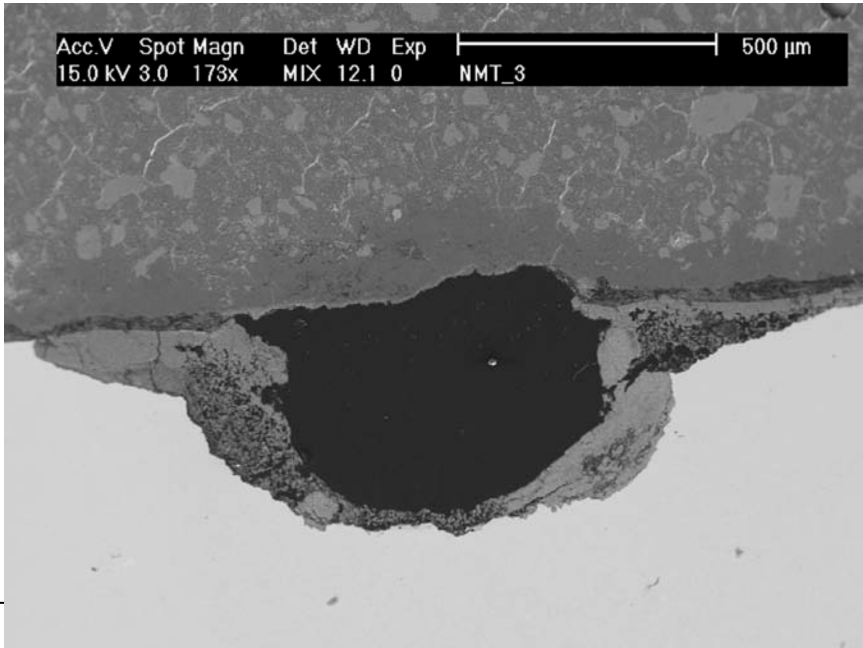
Leakage Pathways in Wellbore Systems



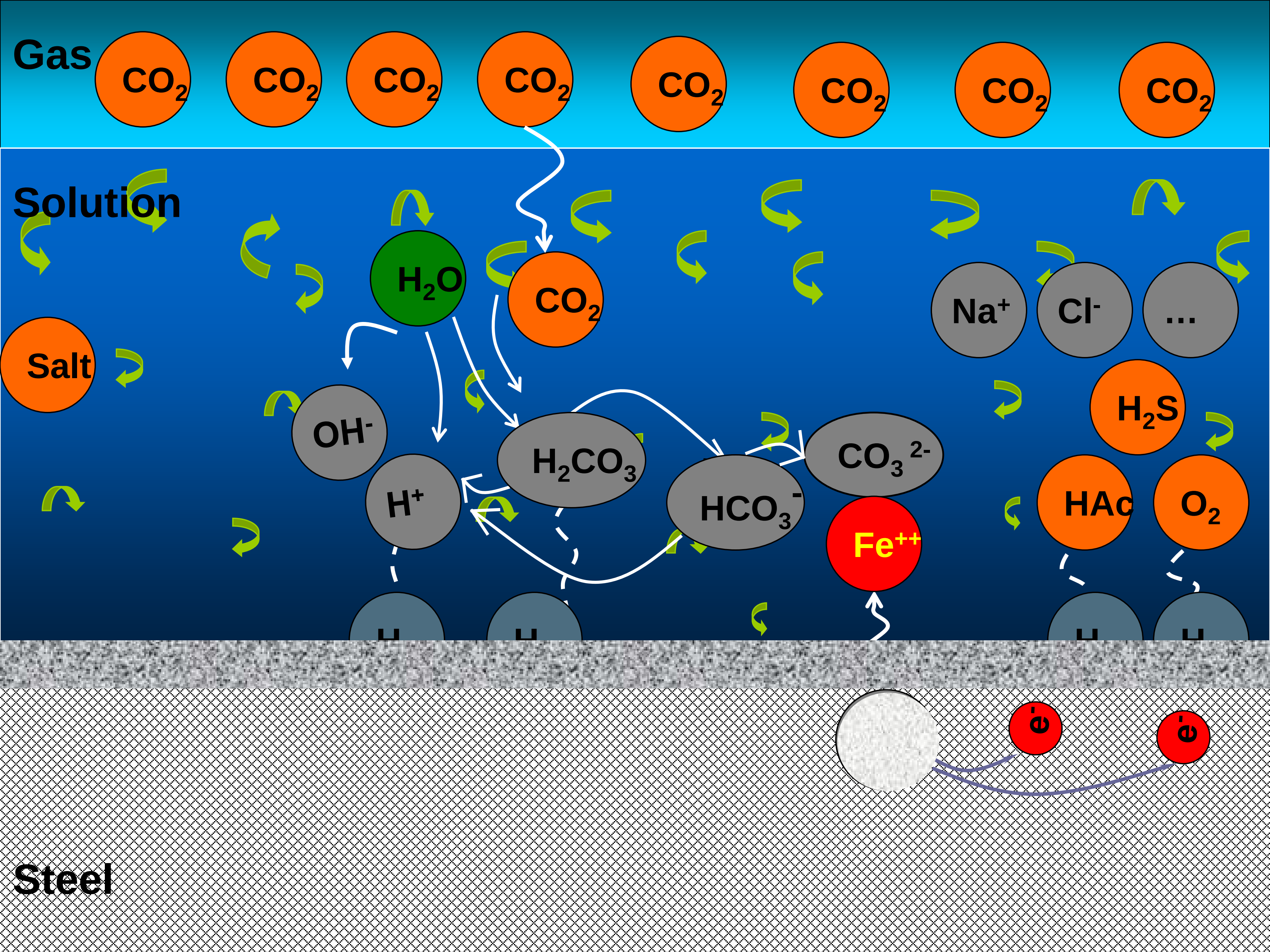
Interface Experiments







Carey et al 2010; IJGGC


Gas
CO2
Solution
H2O
Salt
OH-
H+
H2CO3
HCO3-
CO3 2-
Fe++
Na+
Cl-
...
H2S
HAc
O2
e-
Steel

Corrosion electrochemistry

- **Half cell reactions:**
  - Cathodic reactions:

    $2H_2CO_3(aq.) + 2e^- \rightarrow H_2\ (g.) + 2HCO_3^-\ (aq.)$

    $2H^+\ (aq.) + 2e^- \rightarrow H_2\ (g.)$

    $2H_2O(l.) + 2e^- \rightarrow H_2\ (g.) + 2OH^-\ (aq.)$

    …….

  - Anodic reaction:

    $Fe\ (s.) \rightarrow Fe^{2+}\ (aq.) + 2e^-$

Corrosion kinetics

- **Chemical reaction kinetics:**

$$r_r = k \cdot C_i^x \cdot e^{\left(\frac{E_a}{R \cdot T}\right)}$$

- **Electrochemical reaction kinetics:**

$$i_r = F \cdot C_i^x \cdot e^{\left(\frac{E_a}{R \cdot T}\right)} \cdot e^{\left(\frac{\alpha \cdot n \cdot F \Delta E}{R \cdot T}\right)}$$

Corrosion measurements

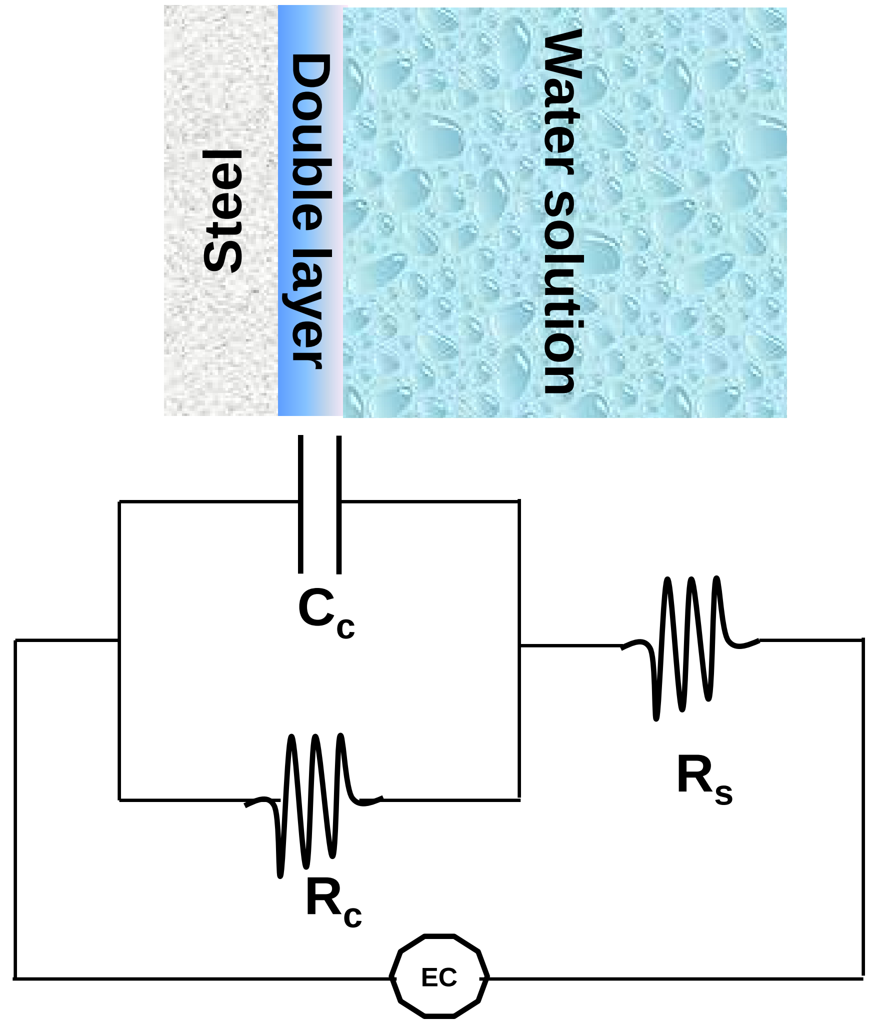
- **Overall Reaction kinetics: Measurement**

$$i_{net} = i_0 e^{\left[\frac{\beta_a \cdot n \cdot F}{R \cdot T} \cdot (E - E^{a}_{rev})\right]} - i_0 e^{\left[\frac{\beta_c \cdot n \cdot F}{R \cdot T} \cdot (E - E^{c}_{rev})\right]}$$

Corrosion measurements

- **Electrode-solution**

- **Measurements:**
  - LPR: $R_t = R_s + R_c$
  - EIS:
    - R_s at high frequency
  - $R_c = R_t - R_s$



pH measurement in cement micro-environment

27.5 mm

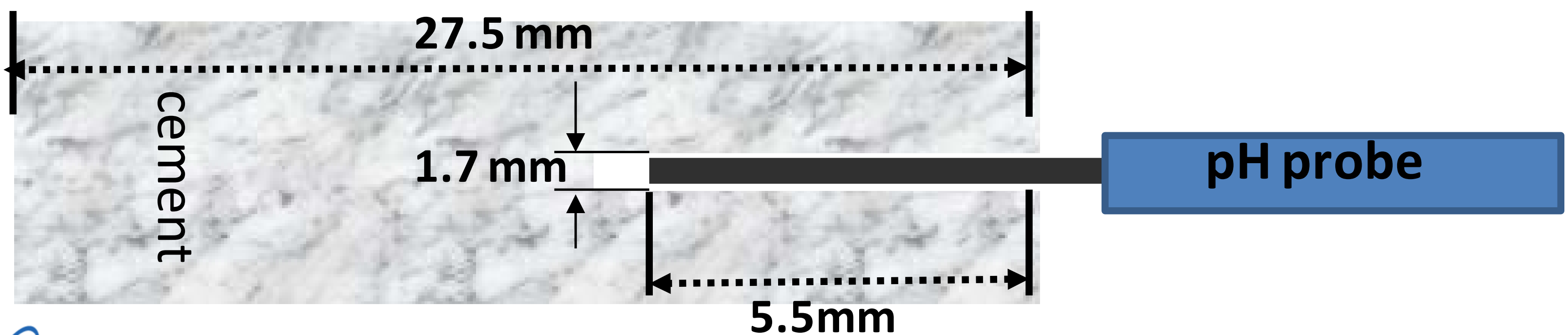
cement

1.7 mm

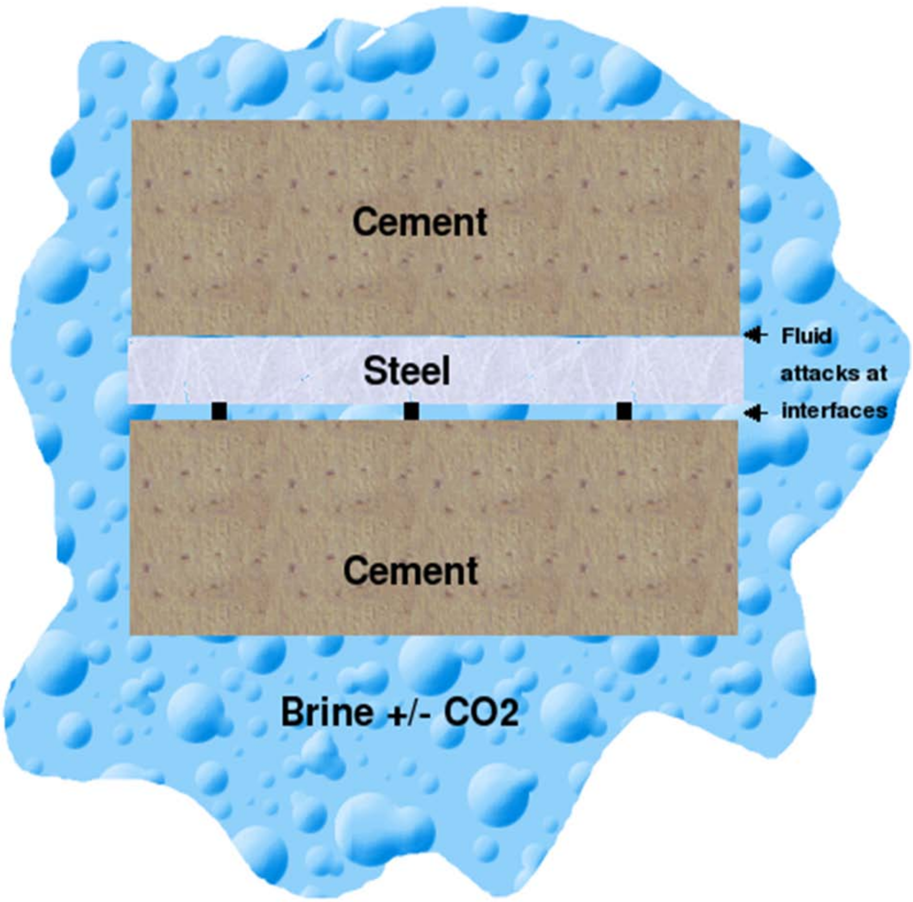
Glue seal

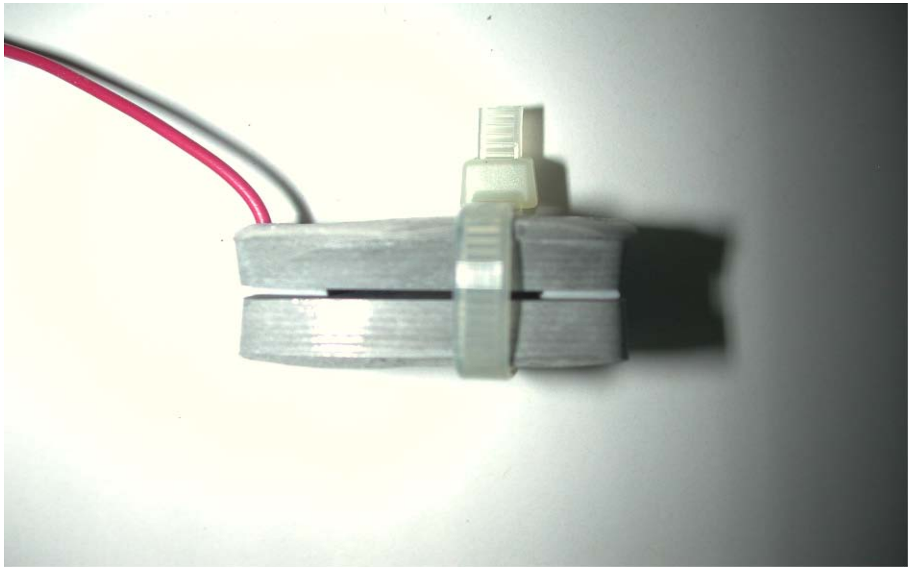
pH probe

5.5mm



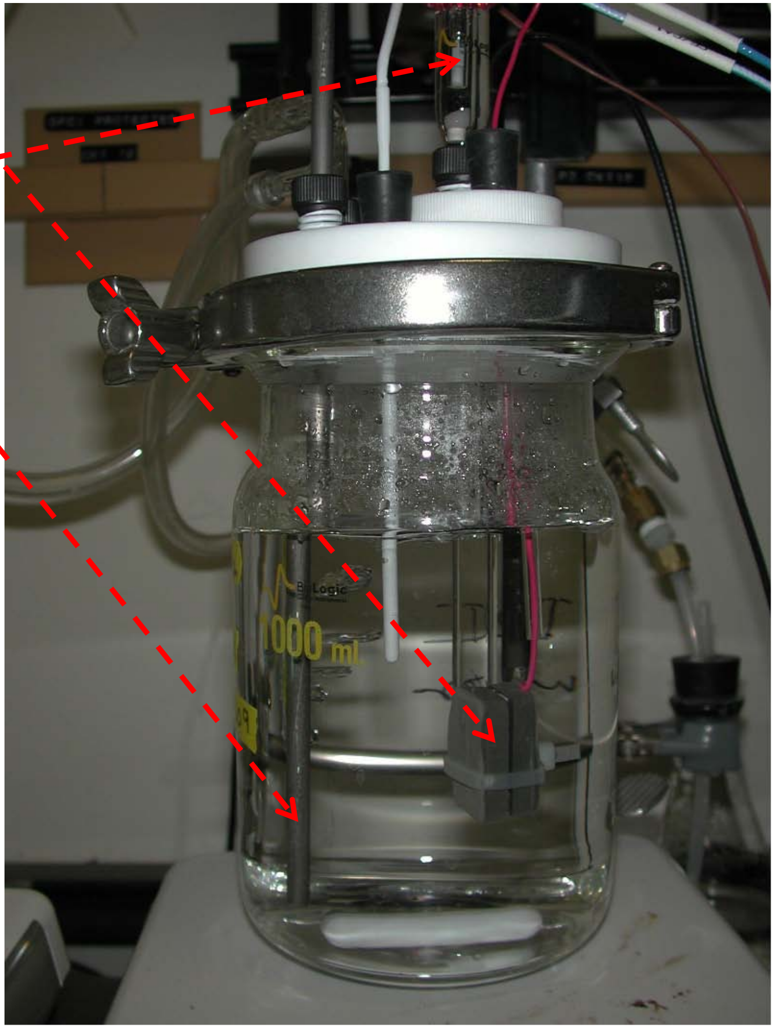
Cement-steel interface design





Experiments: Electrochemical glass cell

- **Electrodes**
  - Working electrode: steel sample
  - Reference electrode: calomel
  - Counter electrode: Titanium
- **Continuously stirred**
- **Positive CO_2 gas flow**
- **Electrochemical impedance spectroscopy**
  - Aqueous system resistivity
- **Linear polarization resistance**
  - Total system resistance



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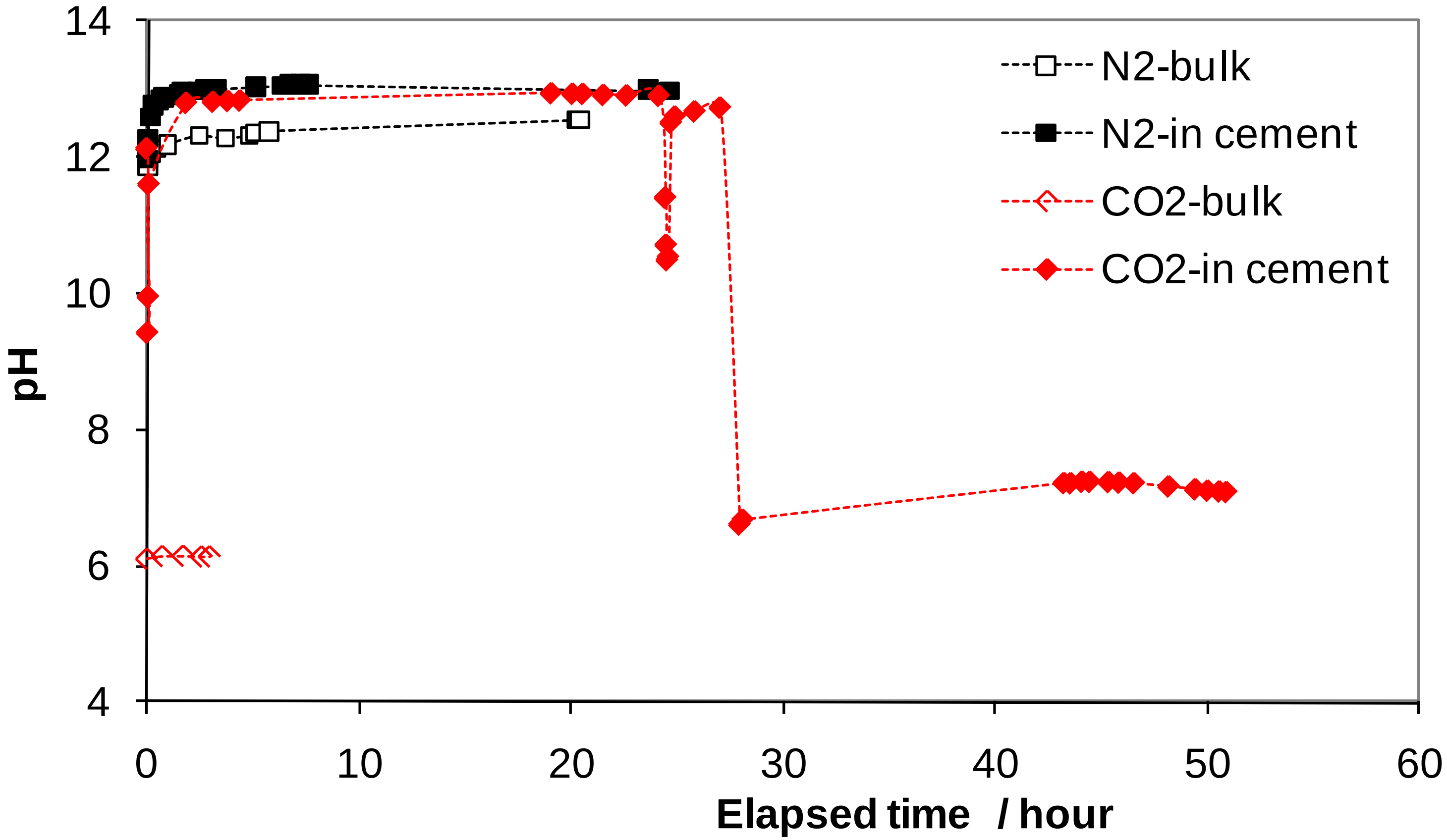
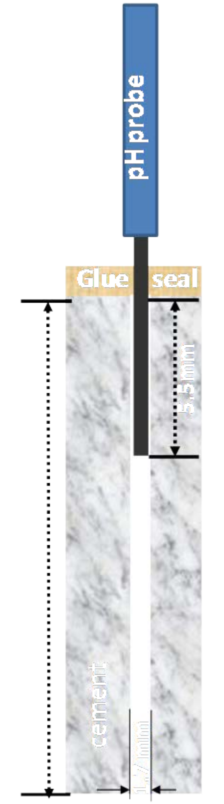
Local pH in cement





T=25 C, ω=300 rpm, P_{total}= 1bar

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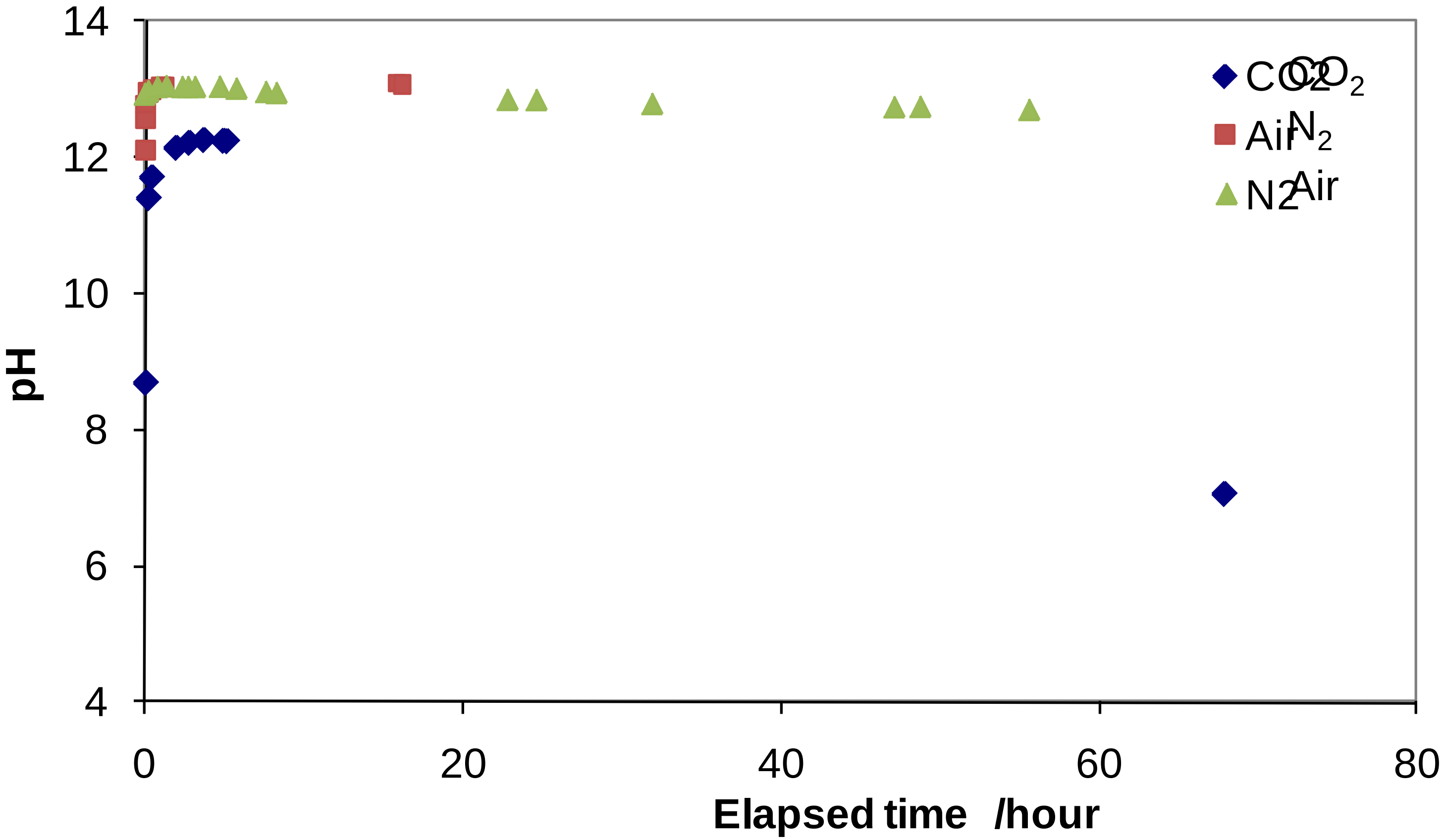
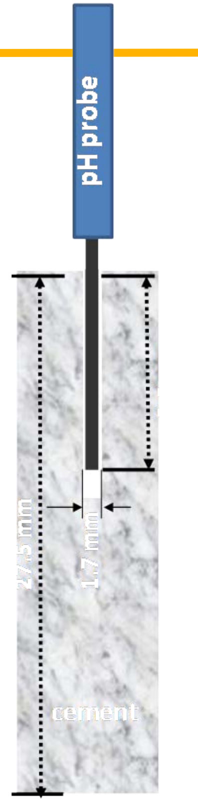
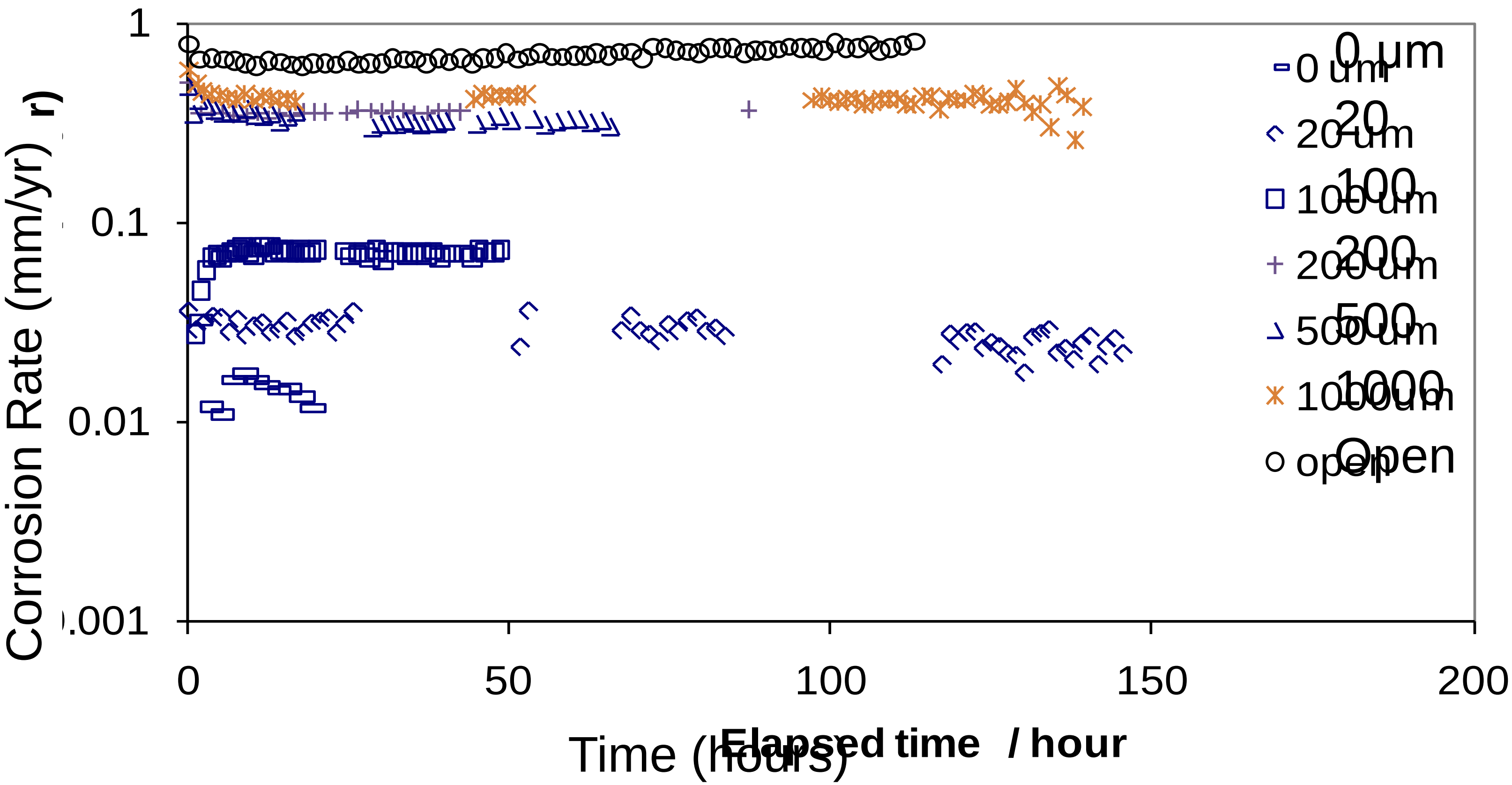
Results: Local pH in cement





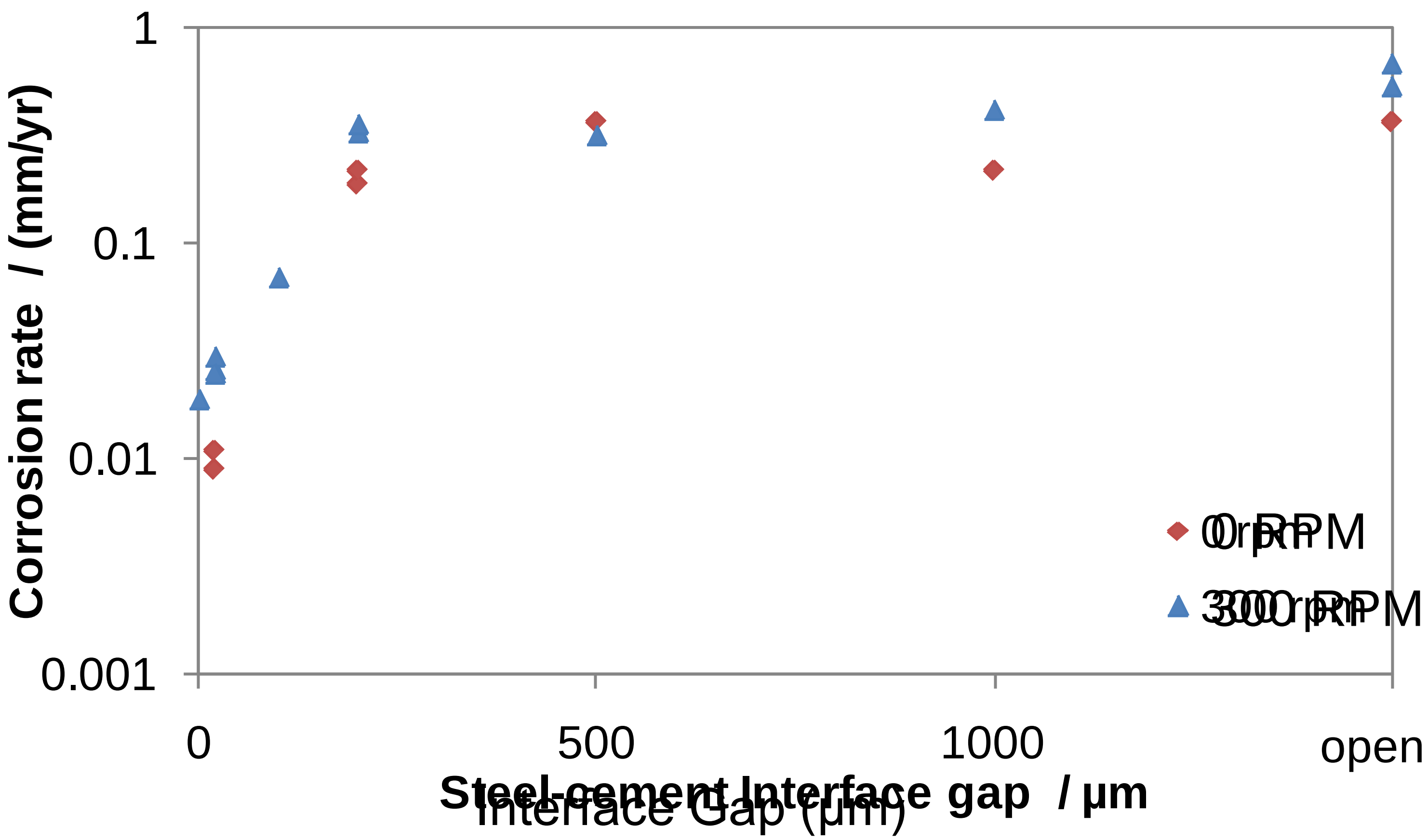
T=25 C, ω=300 rpm, P_{total}= 1bar

Corrosion - interface gap size effect



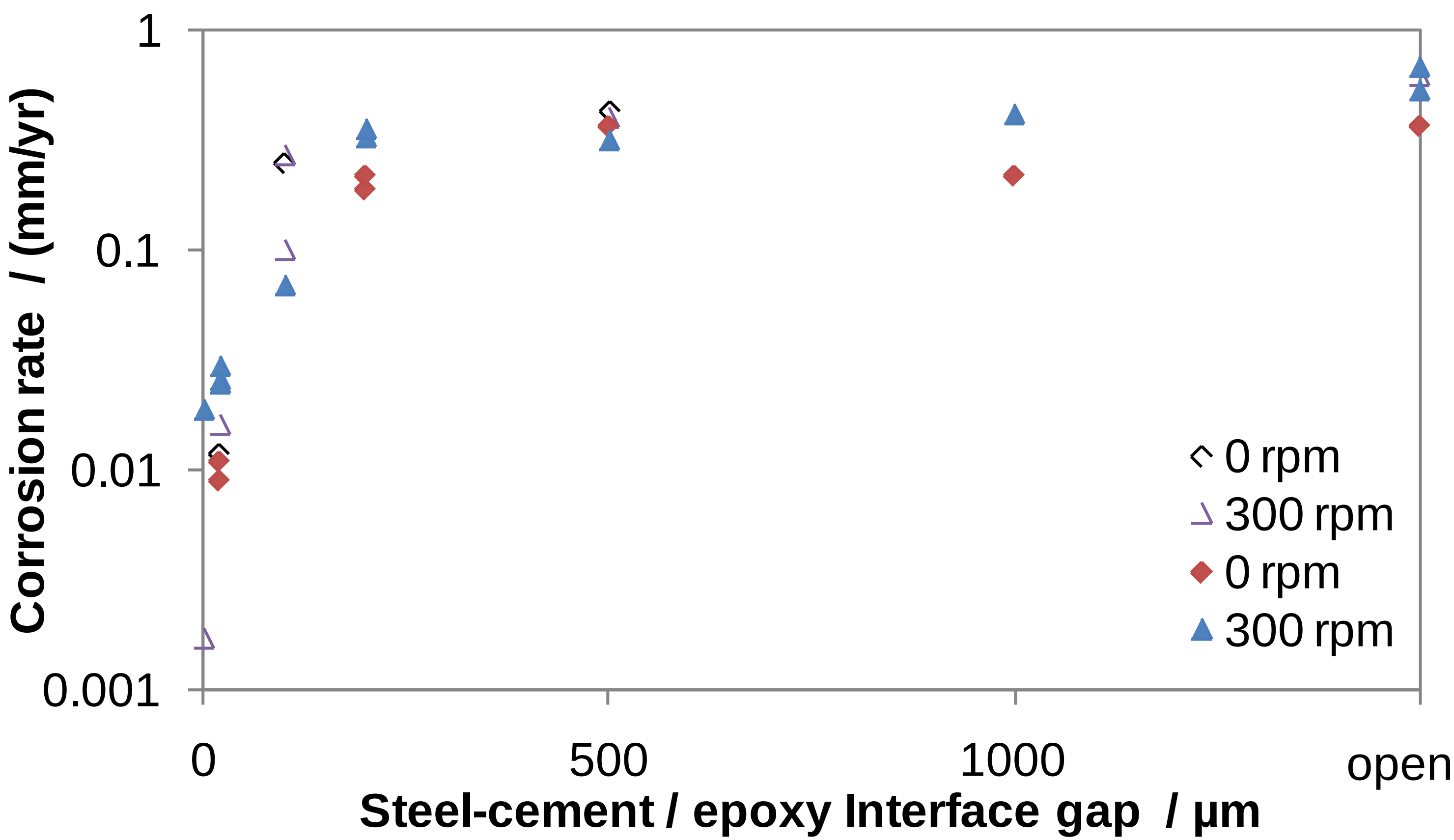
T=25 C, ω=300 rpm, P_{total}= 1bar

Corrosion – interface gap size effect



T=25 C, P_{total}= 1bar

Corrosion – cement versus epoxy



T=25 C, P_{total}= 1bar

Solid marks: steel-cement; Hollow marks: steel-epoxy

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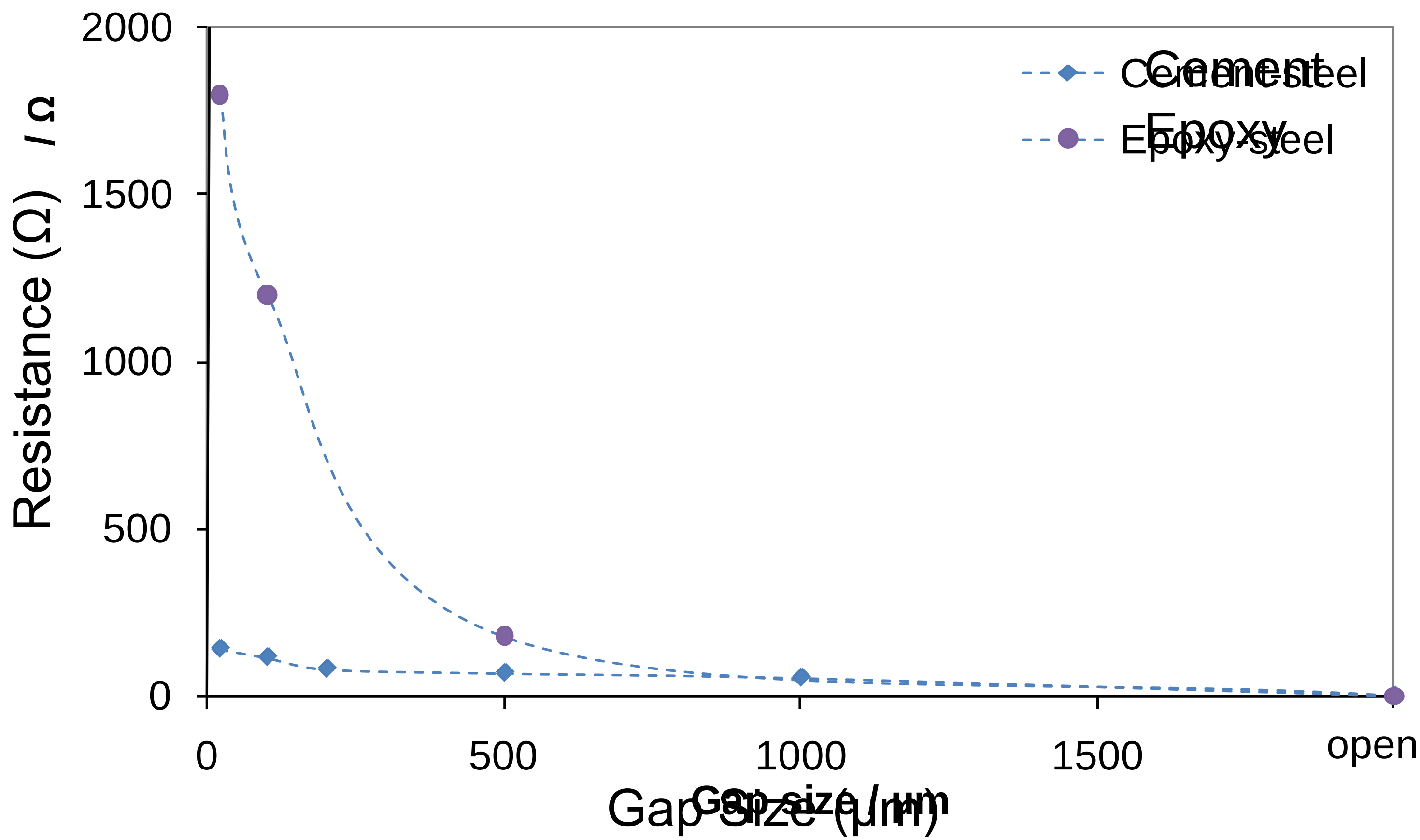
Corrosion – porosity of cement



Solution resistance at T=25 C, ω=300 rpm, P_{total}= 1bar

Conclusions

- **Local water chemistry in cement**
  - pH is > 12 in cement.
  - pH is decreased to <8 by CO_2.
  - pH is greater than bulk solution (≈ 0.5)
- **Corrosion rate increases as cement-steel interface gap size increase**
  - Corrosion is severe at large size (>100 µm)
  - Corrosion is minor at smaller size (>20 µm)
  - Porosity in cement allows corrosion to occur.

Future work

- **Work started at *in situ* high-pressure autoclave**
- **Apply interface gap results to wellbore environments**
  - Corrosion scale.
  - Passivation/depassivation
  - Localized corrosion
- **Obtained information will be incorporated in wellbore integrity model for risk assessment**

Acknowledgements

- **DoE—Fossil Energy**
  - 04FE04-09

- **CO_2 Capture Project**

Corrosion measurements

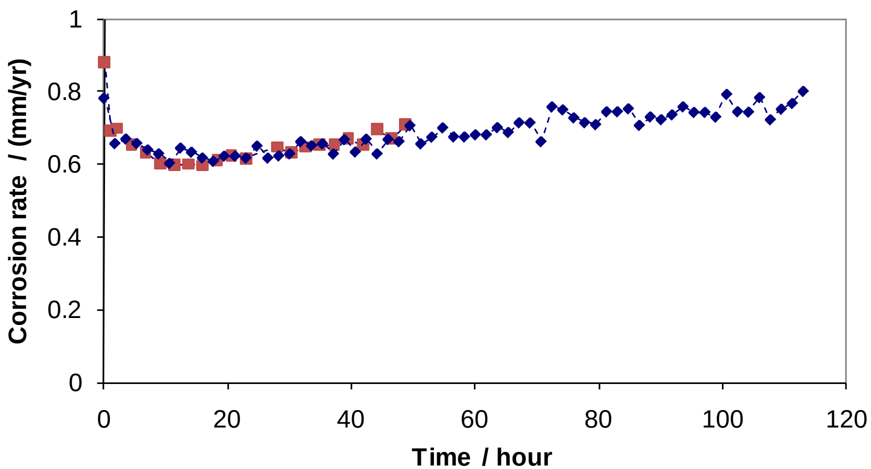
- **Reaction kinetics:**

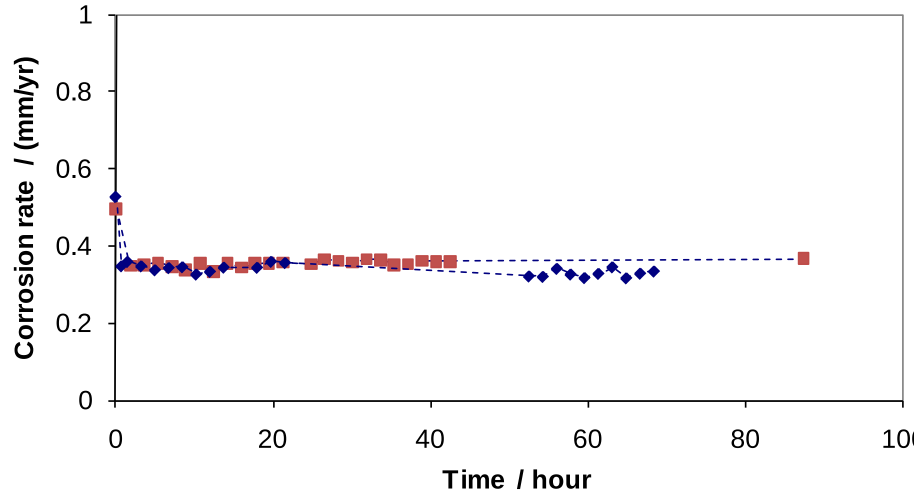
$$i_{net} = i_0 e^{\left[\frac{\beta_a \cdot n \cdot F}{R \cdot T} \cdot (E - E^a_{rev})\right]} - i_0 e^{\left[\frac{\beta_c \cdot n \cdot F}{R \cdot T} \cdot (E - E^c_{rev})\right]}$$

- **Linear polarization resistance: (<10 mV vs. OCP)**

$$i_{corr} = \frac{\Delta i}{\Delta E} \cdot \left(\frac{\beta_a \beta_c}{2.303(\beta_a + \beta_c)}\right) = \frac{B}{R}$$

Corrosion - reproducibility





Gap size=∞ um (open)

Gap size=200 um interface

T=25 C, ω=300 rpm, P_{total}= 1bar

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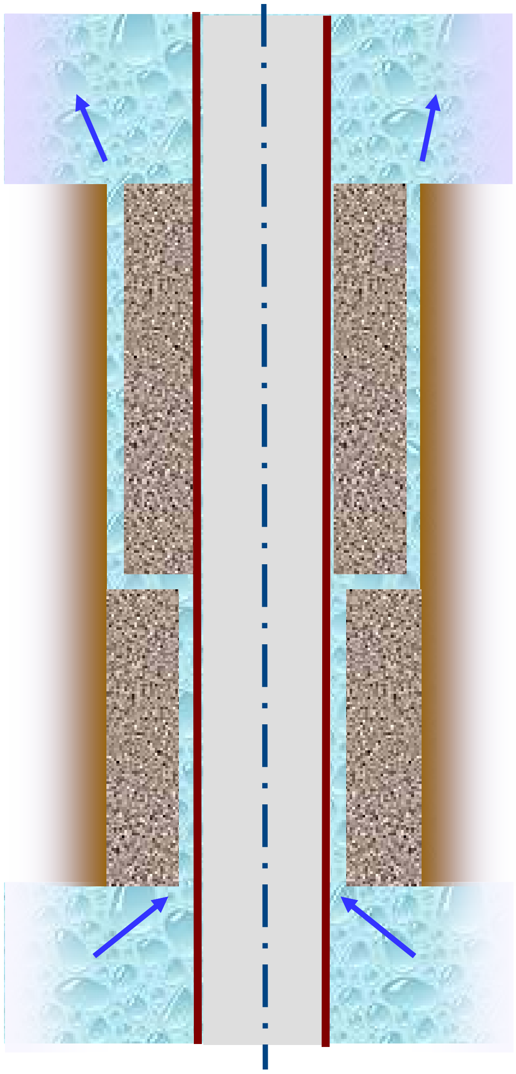
Stability of leakage pathways along a cemented annulus

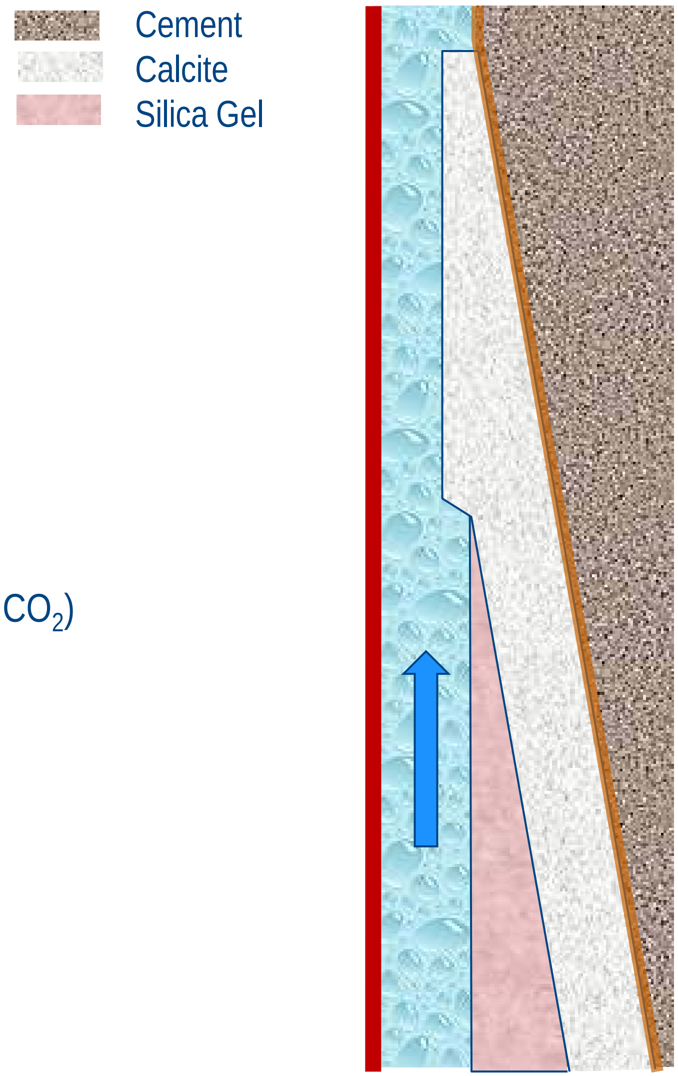
Laure Deremble, Matteo Loizzo,
Bruno Huet, Brice Lecampion, Daniel Quesada

Wellbore integrity failure

- Evidence of a defect:
  - Sustained Casing Pressure
  - Cement Bond log
  - Gas migration
- Defect leads to connectivity
  - Vertical connectivity
    - Inner/outer micro annulus
    - Radial crack
    - Mud channel
  - Horizontal connectivity
    - Disking crack



Origin and fate of a defect



Origin of a defect:

- Bad cementation job
- Cement autogeneous shrinkage (du to self-dessication)
- Pressure/temperature cycling

Evolution of a defect during the life of the well

- Pressurization of the defect (mechanics)
- Thermal expansion/ shrinkage
- Change in the volume of the material:
  - Drying shrinkage
  - Expansion du to cristallisation pressure of calcite
- Change in the mechanical materials properties (reaction with the CO_2)
  - Calcite precipitation
  - Silica gel layer (erosion)
- Clogging of the defect by a solid phase:
  - Precipitation of minerals in the defect space
  - Silica gel deposition
- Clogging of the defect by a liquid phase:
  - Sweating of the cement (reaction creates water)
- Corrosion of the casing

Precipitation of calcite in the defect space

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1. Description of the phenomenon

2. Simulation

3. Stability of the leakage pathway

Precipitation of calcite in the defect space

1. Description of the phenomenon
   - Reaction between the CO_2 and a cement core
   - Evolution of the defect under CO_2 flow
2. Simulation
3. Stability of the leakage pathway

Description of the phenomenon: A cement core in contact with CO_2

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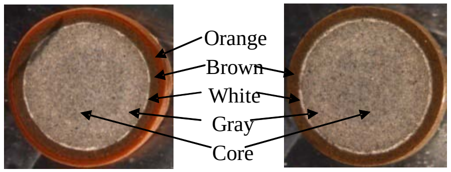
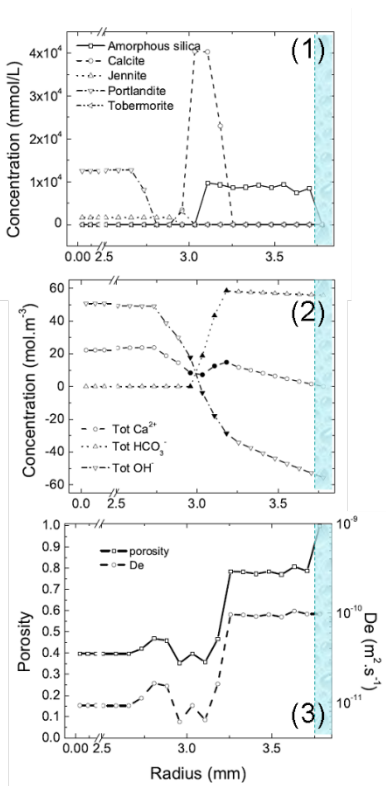
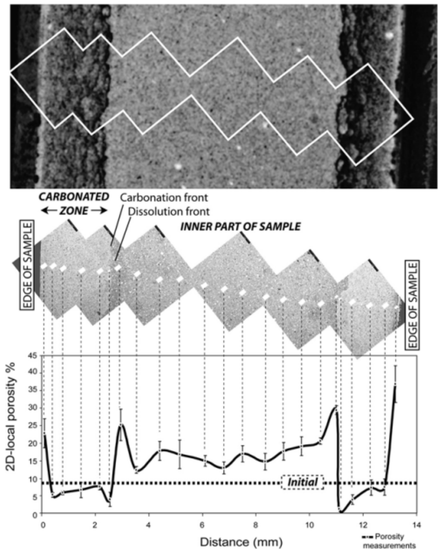


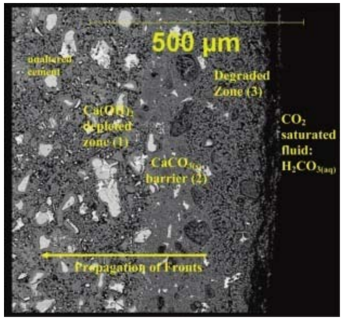
Duguid [2008], SPE 119504



Huet *et al.* [2010]



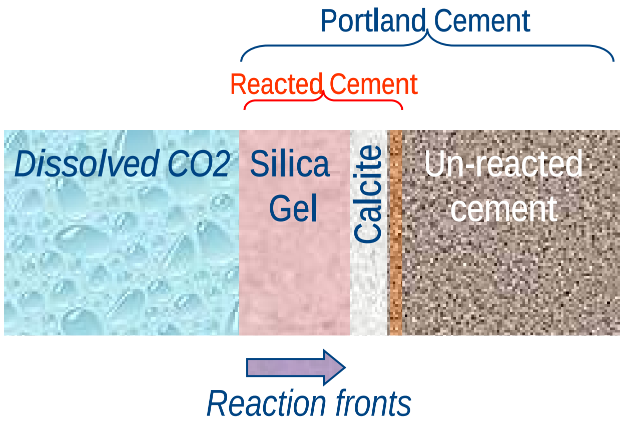
Rimmele *et al.* [2008], C.C.R.



Kutchko *et al.* [2008], Environmental Science & Technology,

Experimental evidences and numerical studies:

- Layer structure



- evolution in $t^{1/2}$ at constant boundary conditions

Description of the phenomenon: Reaction between the cement and the CO_2

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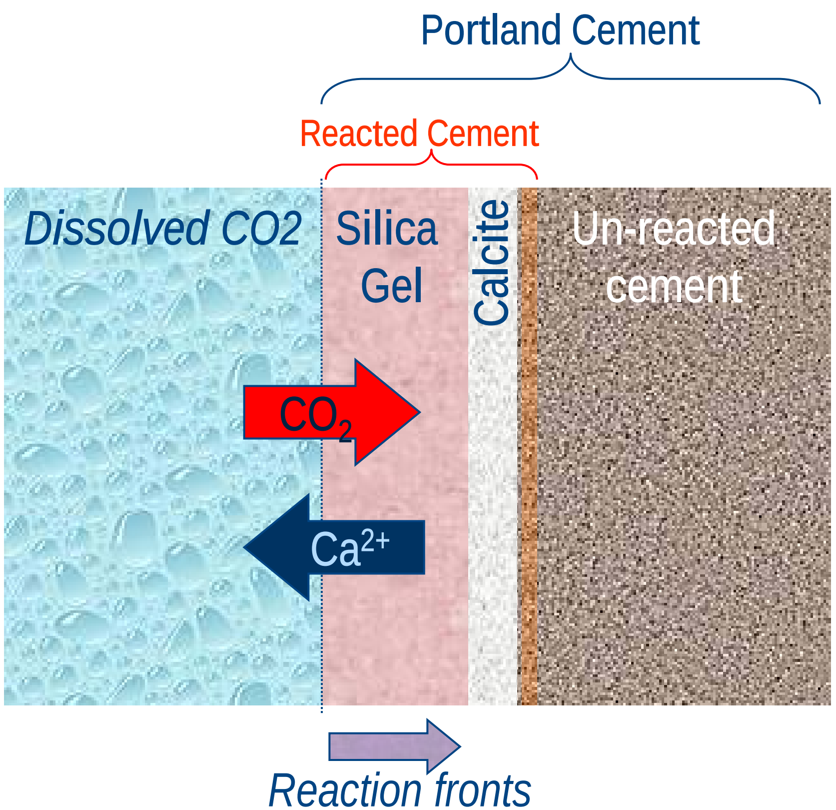
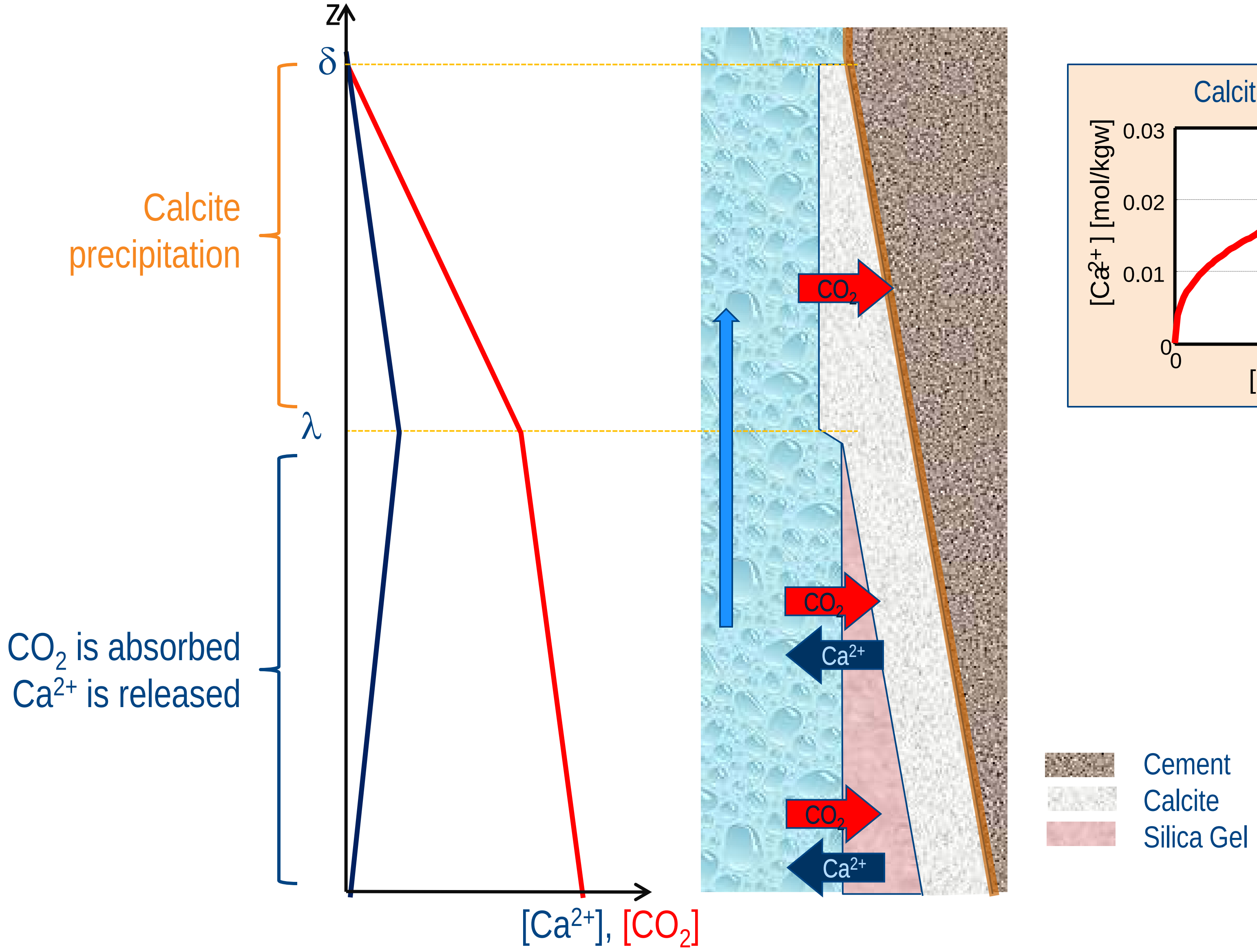
Calcite = $CaCO_3$
Portlandite = $Ca(OH)_2$

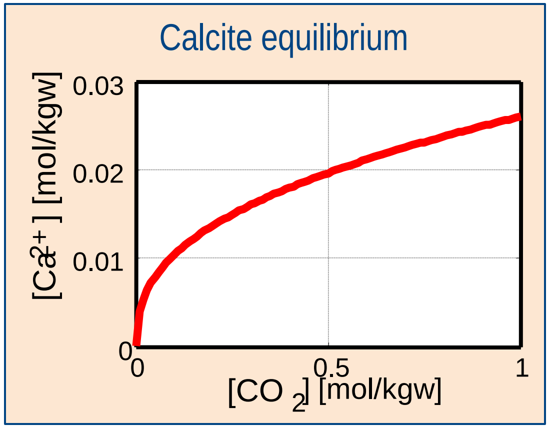
General mass balance:

- A brine charged with CO2 in contact with cement:
  - $[CO_2]$ decreases
  - $[Ca^{2+}]$ increases
- Flux in $t^{-1/2}$



Description of the phenomenon: CO_2 flowing in the defect space





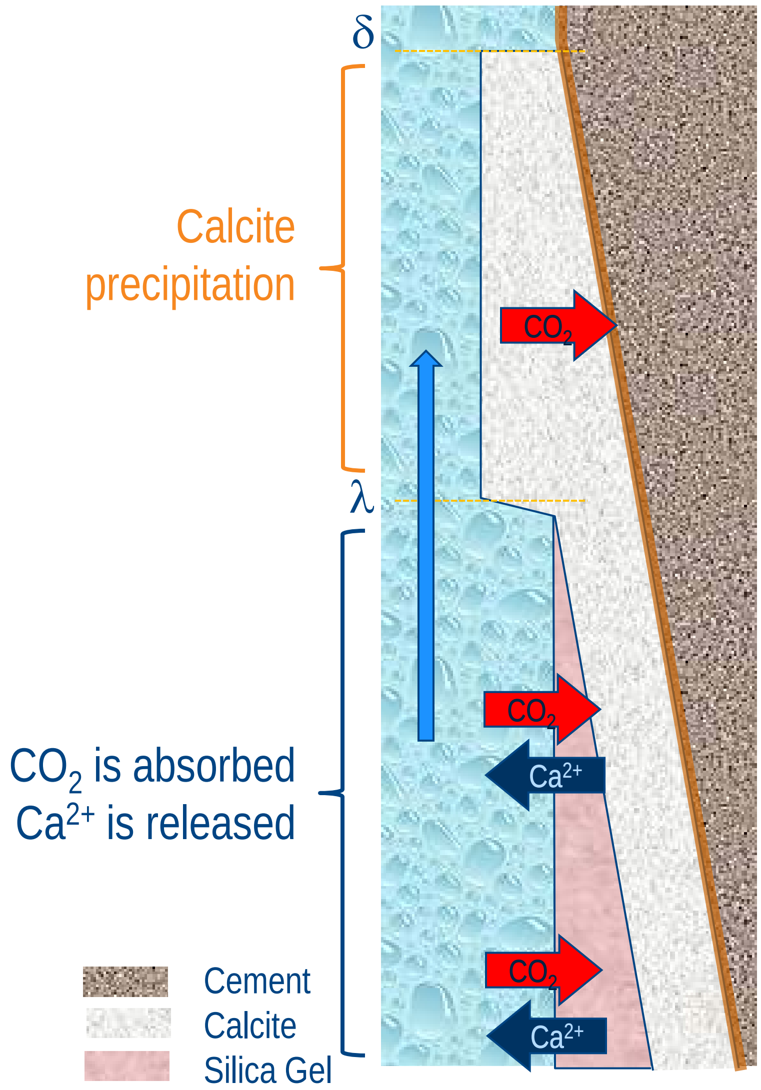
Description of the phenomenon: Evolution of the calcite precipitation zone

Masse balance over CO_2 :

Progression of the precipitation zone $z \in [\lambda, \delta]$

$$v.[CO_2] \sim \sqrt{\frac{\beta_1}{t}}\lambda + \sqrt{\frac{\beta_2}{t}}(\delta - \lambda)$$

$$\Rightarrow \begin{cases} \lambda \sim \sqrt{D_\lambda t} \\ \delta \sim \sqrt{D_\delta t} \end{cases}$$



Description of the phenomenon: Evolution of the calcite precipitation zone

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Masse balance over CO_2 :

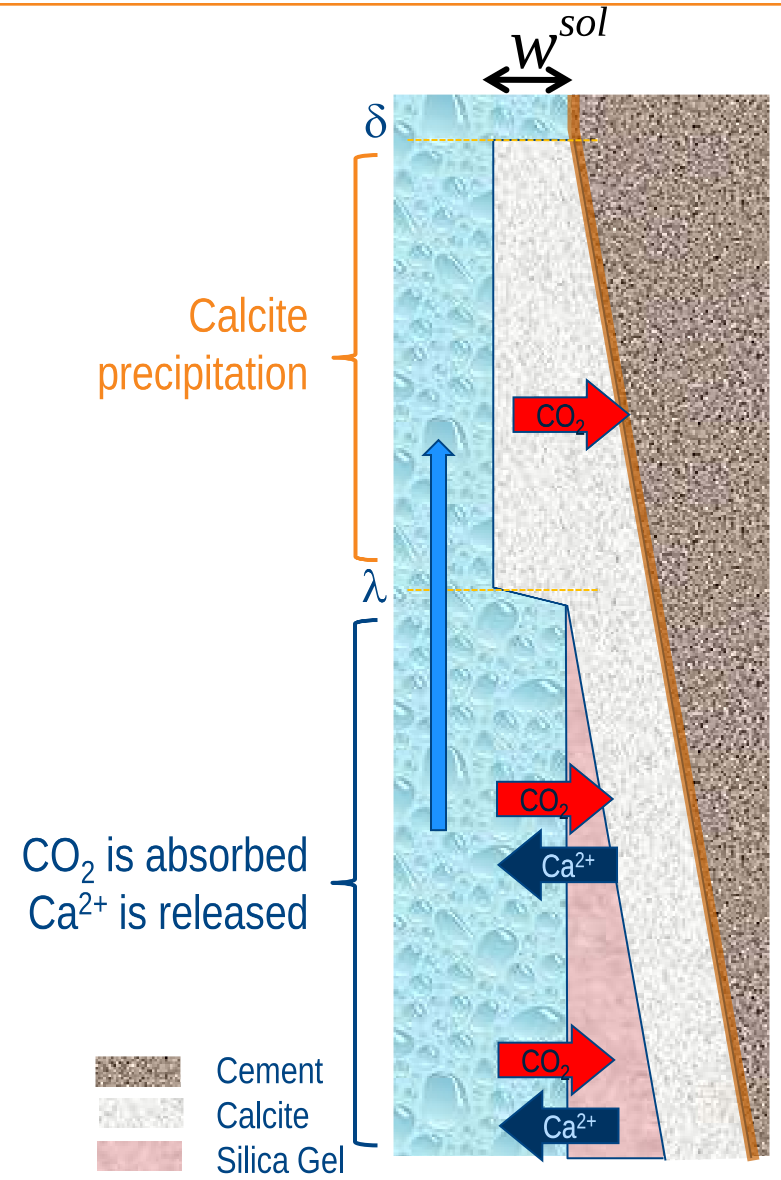
Progression of the precipitation zone $z \in [\lambda, \delta]$

$$\begin{cases} \lambda \sim \sqrt{D_\lambda t} \\ \delta \sim \sqrt{D_\delta t} \end{cases}$$

Masse balance over Ca^{2+} :

Progression of the calcite deposition layer width:

$$\zeta \frac{dw^{sol}}{dt}(\delta - \lambda) \sim \sqrt{\frac{\alpha}{t}}\lambda$$
$$\Rightarrow w^{sol} \approx \sqrt{\kappa t}$$



Description of the phenomenon: Evolution of the calcite precipitation zone

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Masse balance over CO_2 :

Progression of the precipitation zone $z \in [\lambda, \delta]$

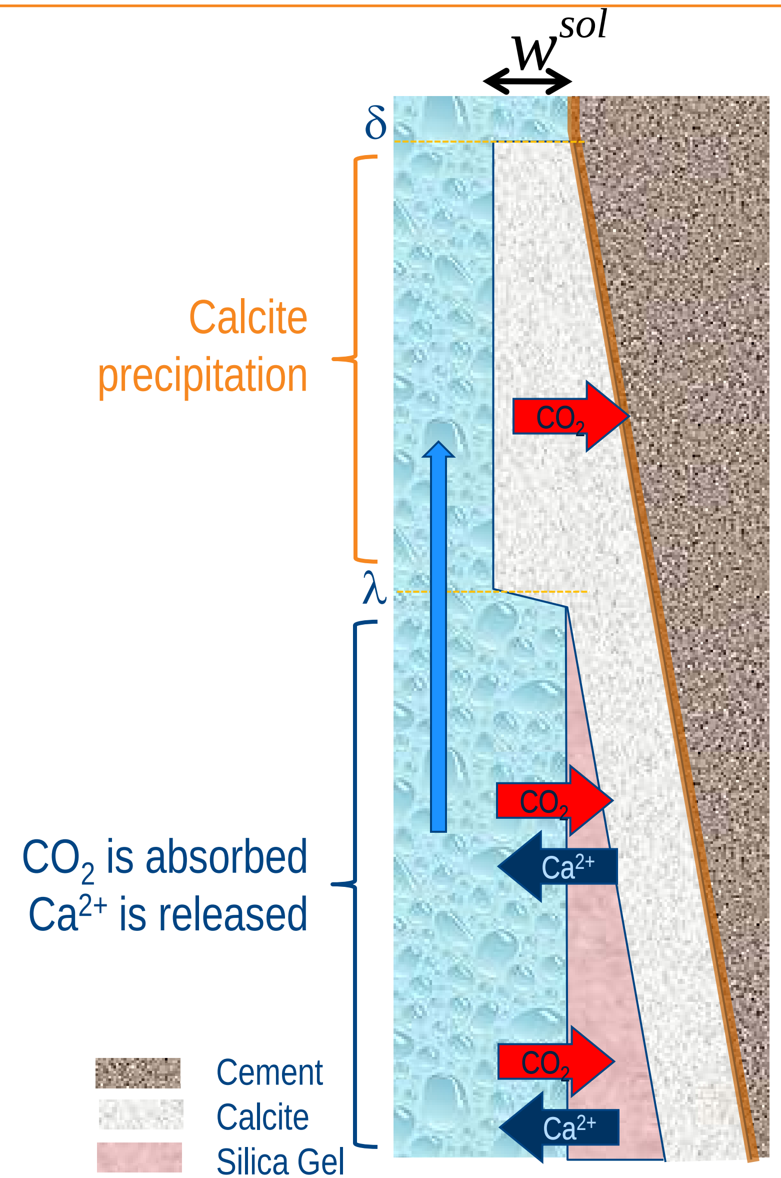
$$\begin{cases} \lambda \sim \sqrt{D_\lambda t} \\ \delta \sim \sqrt{D_\delta t} \end{cases}$$

Masse balance over CO_2 :

Progression of the calcite deposition layer width:

$$w^{sol} \approx \sqrt{\kappa t}$$

→ Evolution as $t^{1/2}$



Will the defect plug?

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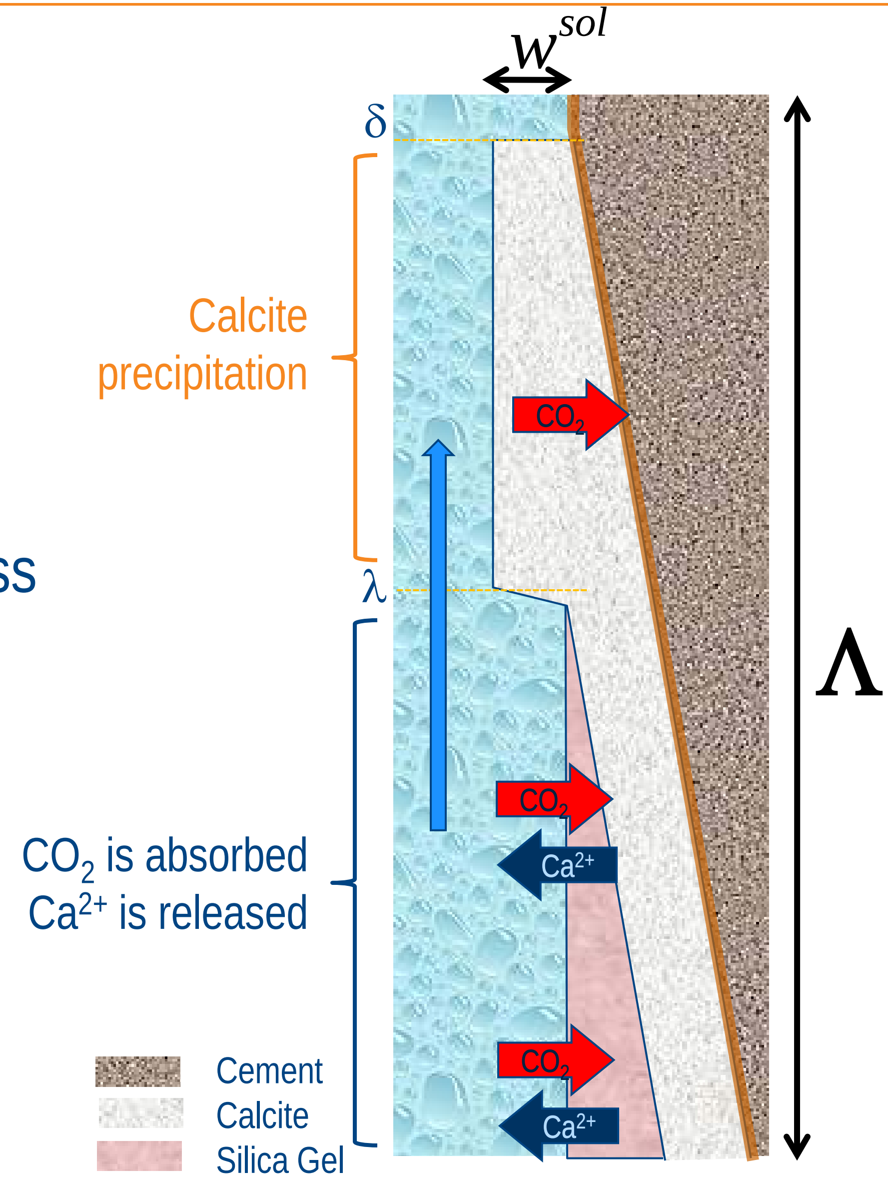
The defect may plug if

$$w^{sol} = w_0 \ \text{for}\ \lambda < \Lambda$$

i.e. if the speed of growth of the calcite deposition is higher than its progress in depth

$$\sqrt{\frac{\kappa}{D_\lambda}} < \frac{w_0}{\Lambda}$$



Precipitation of calcite in the defect space

1. Description of the phenomenon

2. Simulation
   - Writing the equations
   - Examples of numerical result

3. Stability of the leakage pathway

Writing the equation:
General mass balance

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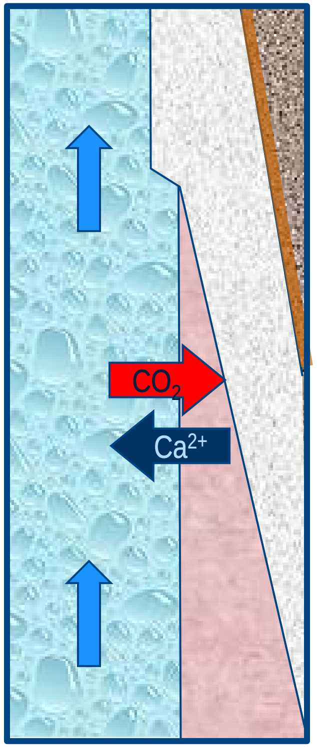
Balancing the convective flux and the flux coming from the reaction between CO2 and cement

$$\frac{\partial}{\partial t}\left(w_0 Z^k \sum_\beta S_\beta \ \zeta_\beta\right)+\frac{\partial}{\partial x}\left(w_0 \sum_\beta S_\beta \zeta_\beta \left(X_\beta^k v_\beta - D_\beta^k \frac{\partial X_\beta^k}{\partial x}\right)\right)= J_{cement}^k$$



Assumptions based on the physics of the phenomena:

- Chemistry: Integration over cement layers
- Hele Shaw assumption for flow rate in the defect
- Spatial decoupling of the 2 phenomena: “1+1D”

Writing the equation:
Focusing on the calcite precipitation

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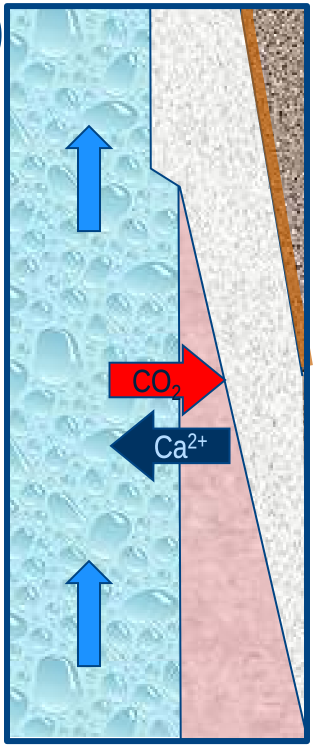
Assumption for this particular study

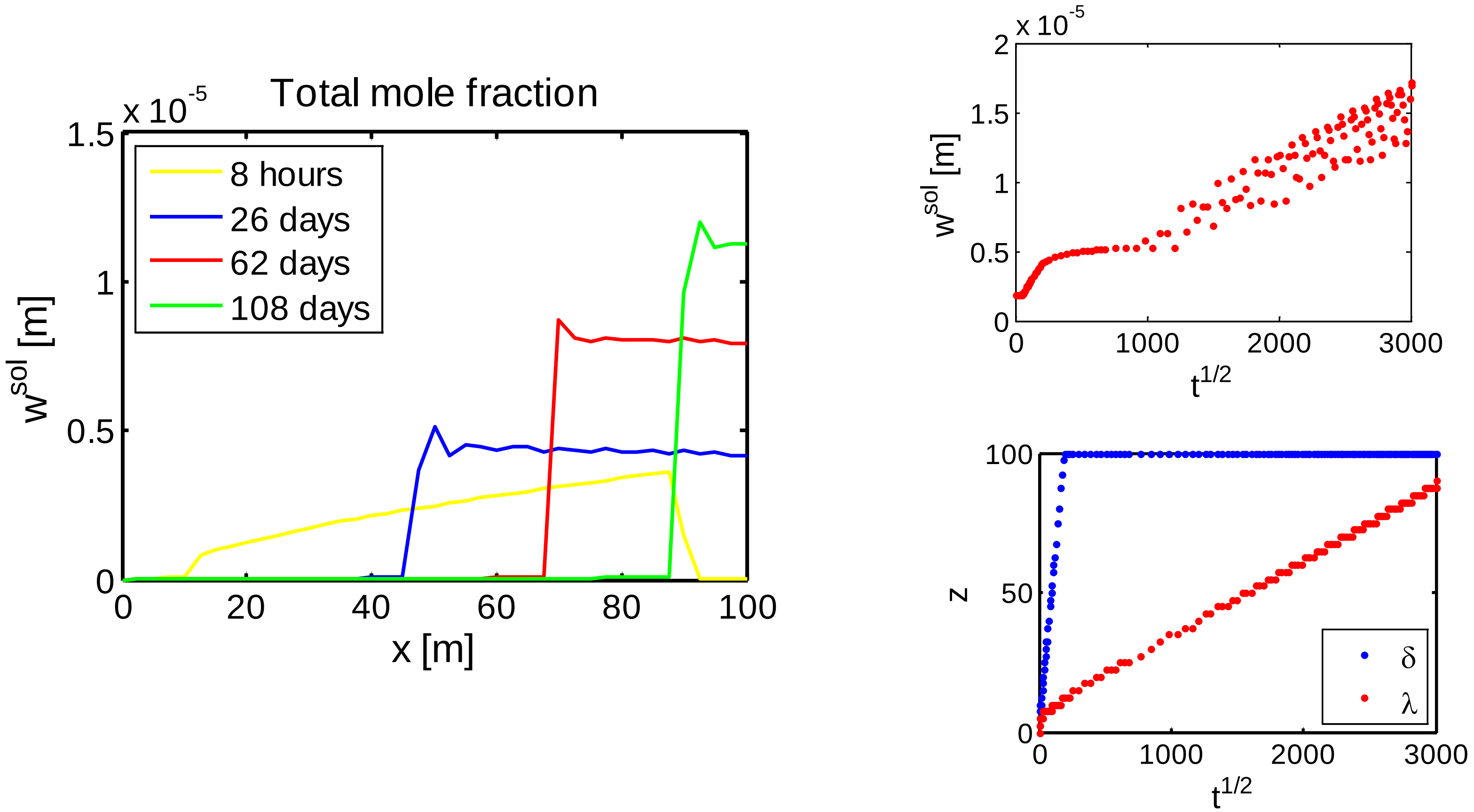
- Diffusion in the convective flow negligible (Péclet number>>1)
- No two-phases flow (bubbling, suspension, etc…)
- No mechanical effect (elasticity, etc…), no compressiblity



$$\frac{\partial}{\partial t}\left(Z^k\left(S_{liq}\ \zeta_{liq}+S_{sol}\ \zeta_{sol}\right)\right)+\frac{\partial}{\partial x}\left(vS_{liq}\ \zeta_{liq}X_{liq}^k\right)=J^k$$

Examples of numerical result:

- Evolution of the calcite precipitation zone with time



Examples of numerical result

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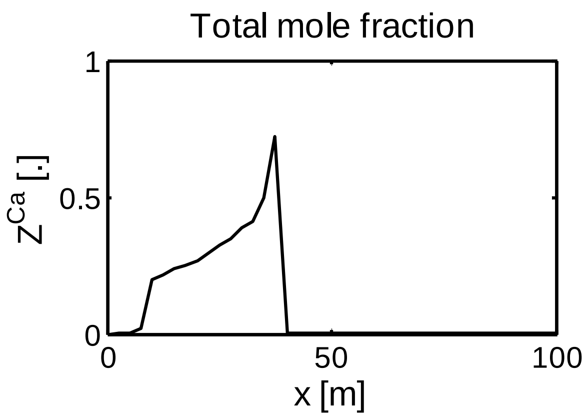
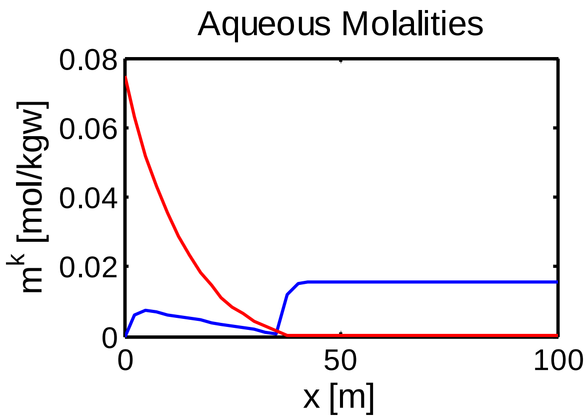
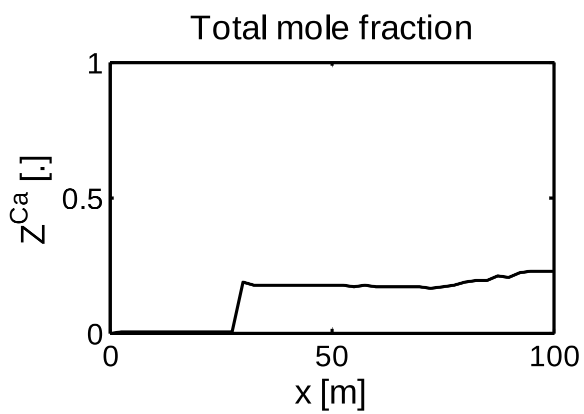
- Evolution for different downhole concentration:

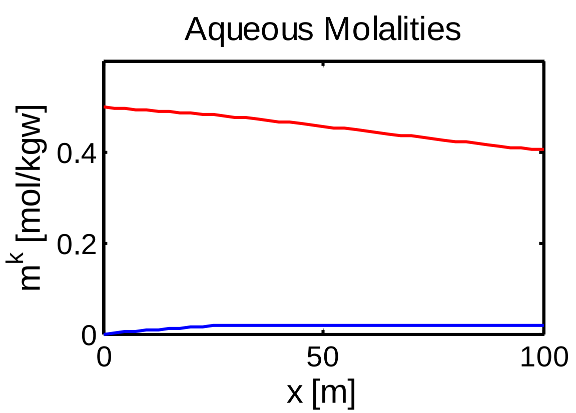
m^{CO2} =75mM
w = 100 mum
ΔP = 30 bars
3months





m^{CO2} =500mM
w = 100 mum
ΔP = 30 bars
23 months





Precipitation of calcite in the defect space

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1. Description of the phenomenon

2. Simulation

3. Stability of the leakage pathway

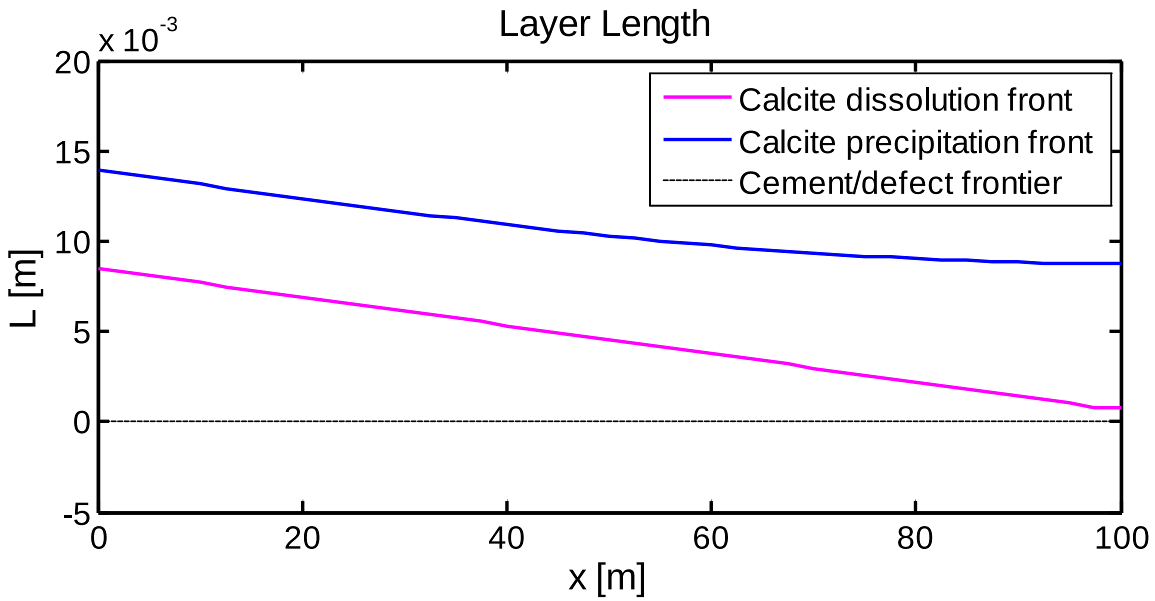
Is there a stability of the leakage pathway?

No stability of a pathway

→ 2 scenarios:

i. ☺ The calcite deposition clogs the defect and stop the evolution

ii. ☹ The calcite deposition do not clog the defect: it will be dissolved and the wellbore cement will fully react.



Stability criterion for risk assessment: Dimensional analysis

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$$\frac{\partial}{\partial t}\left(Z^k\left(S_{liq}\ \zeta_{liq}+S_{sol}\ \zeta_{sol}\right)\right)+\frac{\partial}{\partial x}\left(vS_{liq}\ \zeta_{liq}X^k_{liq}\right)=J^k$$

- 3 dimensionless groups: $\begin{cases} G_{\delta l}=\dfrac{\zeta_l}{\zeta_s-\zeta_l} \\ G_D=\dfrac{D_{calcite}}{D_{SG}} \\ G_\mu=\dfrac{w_0^4\Delta\tilde{P}m_0^{CO_2}\rho_w}{12\mu_f\Lambda^2D_1c_s}=\dfrac{t_\chi}{t_\mu} \end{cases}$

- 2 dimensional parameters: $\begin{cases} m_0^{CO_2} \\ m_0^{Ca^{2+}} \end{cases}$

- Characteristic values: $\begin{cases} Z_0^{CO_2}\approx\dfrac{m_0^{CO_2}}{m_w} \\ t^*=t_\chi=\dfrac{w_0^2m_0^{CO_2}\rho_w}{c_sD_1} \\ J^*=\dfrac{D_1c_s}{w_0} \end{cases}$

Stability criterion for risk assessment: Dimensional analysis

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$$\frac{\partial}{\partial t}\left(Z^k\left(S_{liq}\ \zeta_{liq}+S_{sol}\ \zeta_{sol}\right)\right)+\frac{\partial}{\partial x}\left(vS_{liq}\ \zeta_{liq}X_{liq}^k\right)=J^k$$

- 3 dimensionless groups: $\begin{cases} G_{\delta l}=\dfrac{\zeta_l}{\zeta_s-\zeta_l} \\ G_D=\dfrac{D_{calcite}}{D_{SG}} \\ G_\mu=\dfrac{w_0^4\Delta\tilde{P}m_0^{CO_2}\rho_w}{12\mu_f\Lambda^2 D_1 c_s}=\dfrac{t_\chi}{t_\mu} \end{cases}$

- 2 dimensional parameters: $\begin{cases} m_0^{CO_2} \\ m_0^{Ca^{2+}} \end{cases}$

- Characteristic values: $\begin{cases} Z_0^{CO_2}\approx\dfrac{m_0^{CO_2}}{m_w} \\ t^*=t_\chi=\dfrac{w_0^2 m_0^{CO_2}\rho_w}{c_s D_1} \\ J^*=\dfrac{D_1 c_s}{w_0} \end{cases}$

Stability criterion for risk assessment: Is the defect self-healing?

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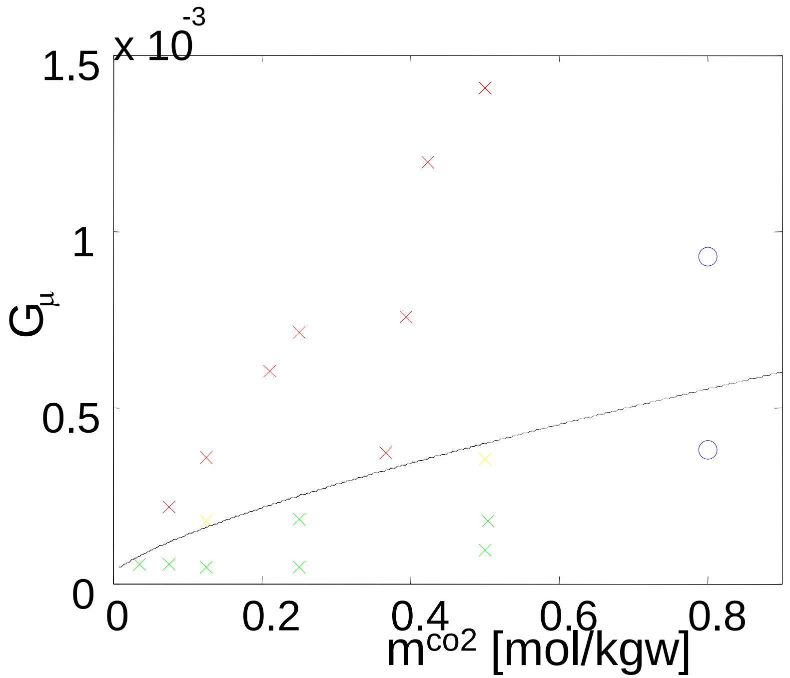
Simulation at constant cement properties

X: ☹ no plugging

X: ☺ plugging

$$G_\mu = \frac{w_0^4 \Delta \tilde{P} m_0^{CO_2} \rho_w}{12 \mu_f \Lambda^2 D_1 c_s}$$



Forecast for injection condition:

- 50 bars
- Defect over 100m of wellbore length
- Width of the defect : 100 µm or 80 µm

High sensitivity to the initial width of the defect

Conclusion

Summary:

- Calcite precipitation: mechanism of defect clogging
- Stability criterion for given defect and injection conditions

Way forward

- Experimental / Field evidence of clogging
- Other evolution of the defect width can be studied in that point of view
  - Corrosion
  - Expansion of the cement
  - Etc…

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Cement Carbonation in Brine: Controversy or consistency ?

Bruno Huet, Ines Khalfallah

Outline

- Experimental evidence on Portland cement: controversy?
  - Experimental conditions (Duguid, Barlet-Gouedard and Kutchko)
  - Rates
  - Main features
- Reactive transport modeling: consistency !
  - How to use
  - Simulation results
- Conclusion:
  - Consistency
  - Need for further experiments

Experimental evidence

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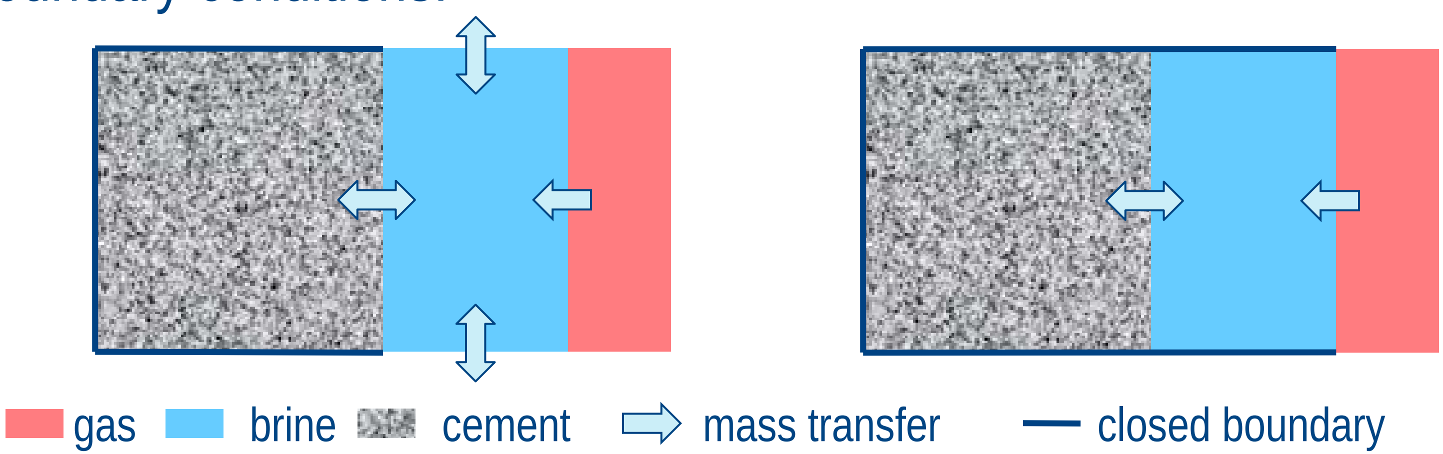
- Experimental conditions summary:

Parameter	Duguid	Barlet Gouedard	Kutchko
P [bar]	1	280	303
T [°C]	25	90	50
NaCl [molal]	0.5	0	0.17
Cement	Portland	Portland	Portland
Boundary conditions - Brine	Open	Closed	Closed
Boundary conditions - Gas	Open	Open	Open

- Boundary conditions:



Experimental evidence

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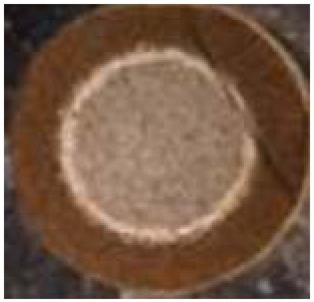
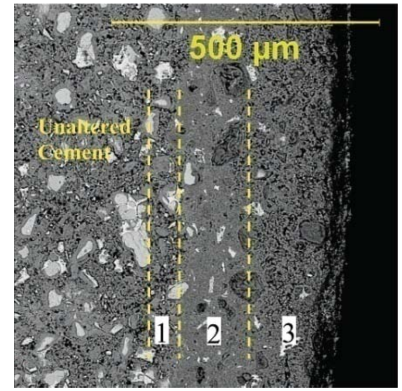
- Main features:



Duguid 2005, 2009

Barlet-Gouedard 2006



Kuchko 2008

- Reacted layer thicknesses

Initial cement

Parameter	Duguid	Barlet Gouedard	Kutchko
Ca depleted layer	~1 mm	<100 µm	~200 µm
Calcite layer	~200 µm	~1 mm	~200 µm
C-S-H layer	~ 0.5 mm ?	<100 µm	<100 µm

Experimental evidence

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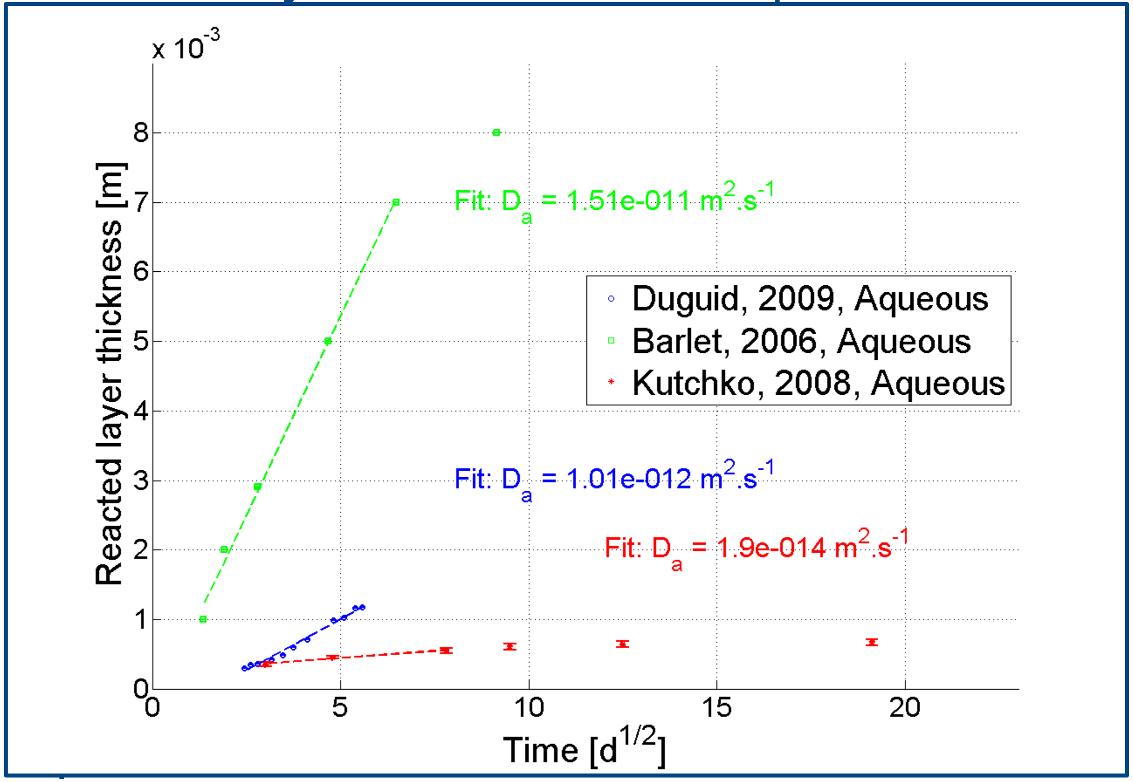
- Rates: total reacted layer thicknesses vs sqrt of time



- Two mechanisms:
  - Diffusion controlled
  - Passivation

The controversy

Schlumberger
Carbon Services

- Summary
  - Main different experimental conditions
    - Temperature
    - Boundary conditions
  - Main Mechanisms
    - Calcium depletion
    - Hydrates carbonation
    - Pore clogging

Outline

Schlumberger Carbon Services

- Experimental evidence on Portland cement: controversy?
  - Experimental conditions (Duguid, Barlet-Gouedard and Kutchko)
  - Rates
  - Main features
- **Reactive transport modeling: consistency !**
  - **How to use**
  - **Simulation results**
- Conclusion:
  - Consistency
  - Need for further experiments

Reactive Transport Models: how to use

Schlumberger Carbon Services

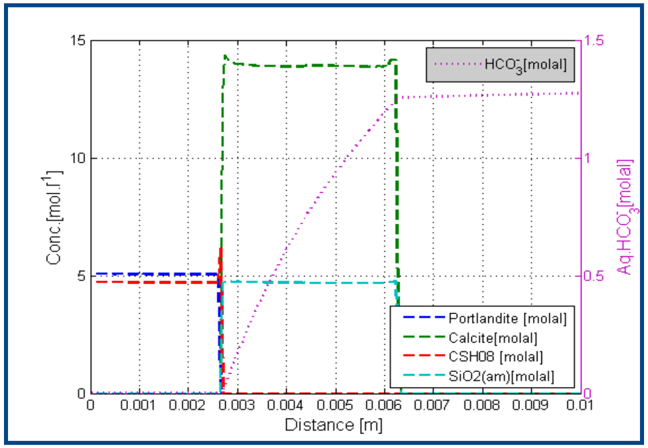
$$\frac{\partial}{\partial t}(\varphi C_i) = \frac{\partial}{\partial x}\left(\varphi D_p \frac{\partial}{\partial x} c_i\right)$$

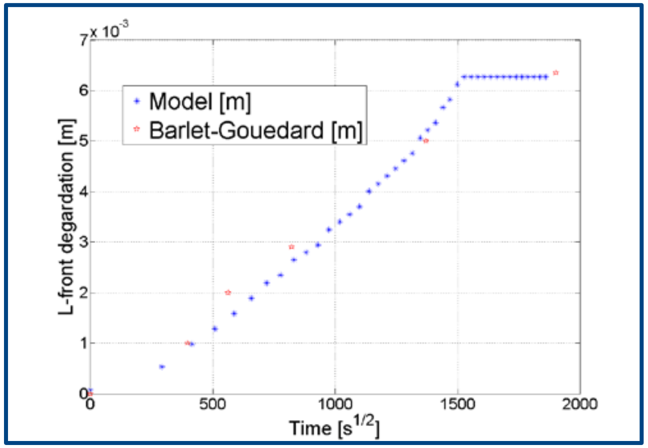
Reactive transport codes:

- DYNAFLOW, HYTEC, TOUGHREACT,.....

Simulate exact experimental conditions:

- Chemistry:
  - Full aqueous/mineral chemistry (dissolution/precipitation, hydrolysis, complexation)
  - Cement composition (CH, C-S-H, AFm, AFt)
  - Brine Composition (NaCl, CO_2)
- Transport:
  - Boundary conditions
  - Open or closed system (V_{brine}/V_{cem})
  - Diffusion (no advection): $D_e = \varphi \cdot D_b / \tau(\varphi)$





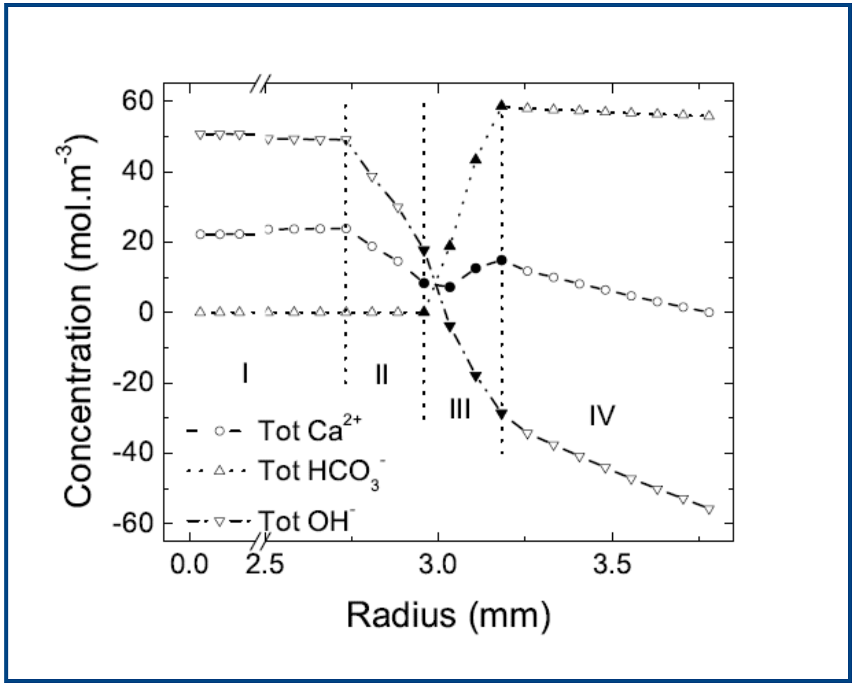
Analyze key features and compare with experiments:

- Spatial distribution of minerals and porosity
- Concentration profiles and fluxes of aqueous species
- Local equilibrium: no need for reaction kinetics

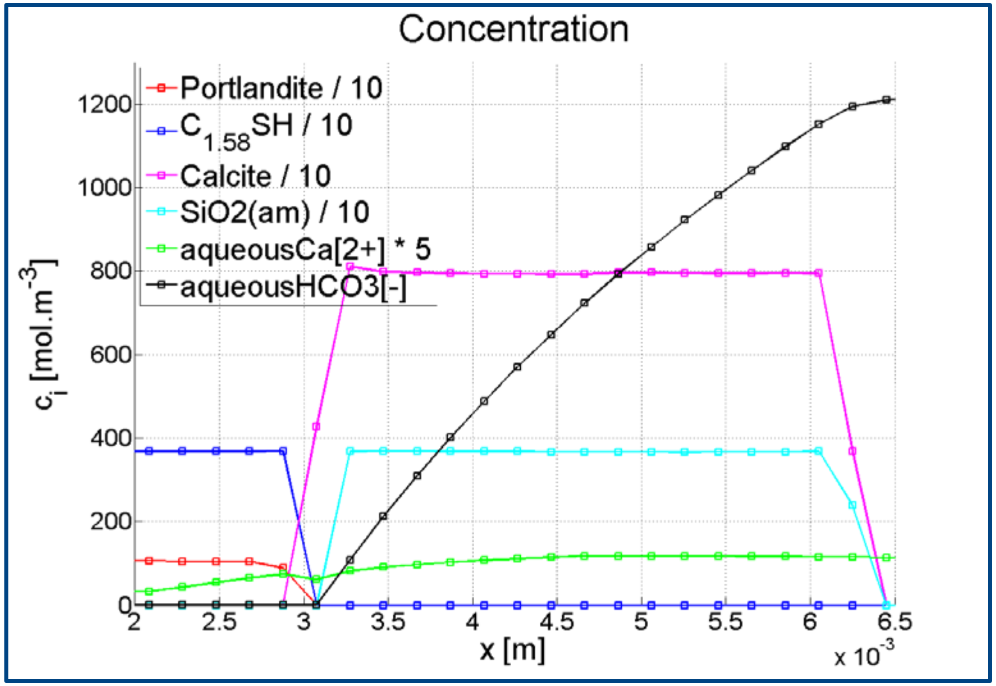
The "boundary conditions" effects: Duguid vs Barlet-Gouedard

Schlumberger Carbon Services

- Open system (= renewed brine):



- Closed system:

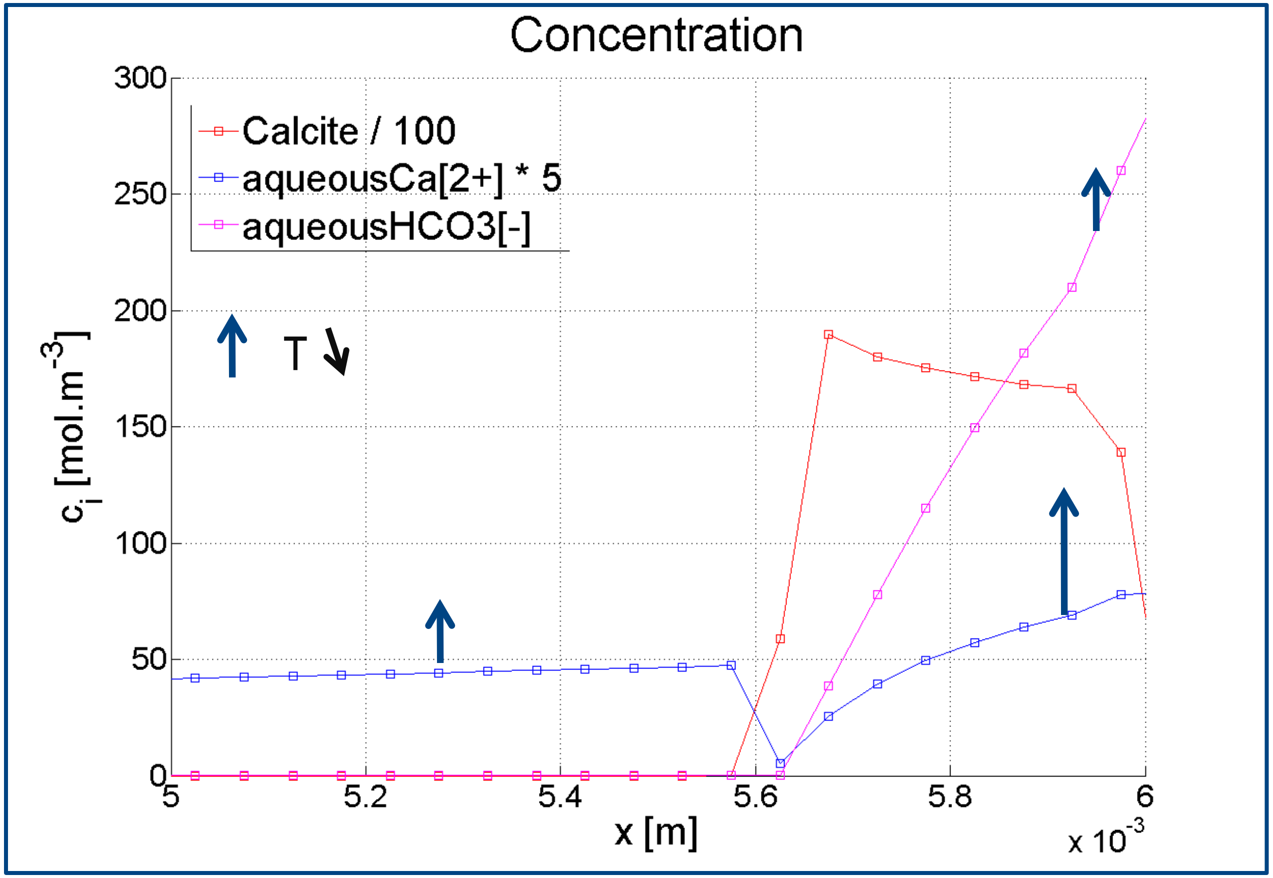


Huet et al. 2010

- Conclusion: Ca leaching vs CO_2 ingress

The “temperature” effects: Kutchko vs Barlet-Gouedard

- The “temperature” effects = Kutchko vs Barlet-Gouedard



- Calcium accumulation at calcite formation front ⇒ Pore clogging !

Conlusion

Schlumberger Carbon Services

- Consistency: reactive transport models can explain experiments
  - Three main mechanisms:
    - Calcium leaching
    - Carbonate ingress through carbonate layer
    - Pore clogging = accumulation of Ca in addition to C locally
  - Related to:
    - Boundary conditions
    - Temperature (phase solubility)

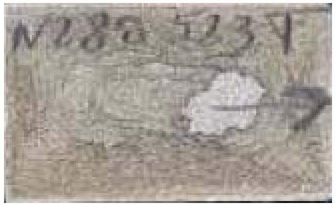
- Need for further experiments !
  - Check transition conditions between mechanisms

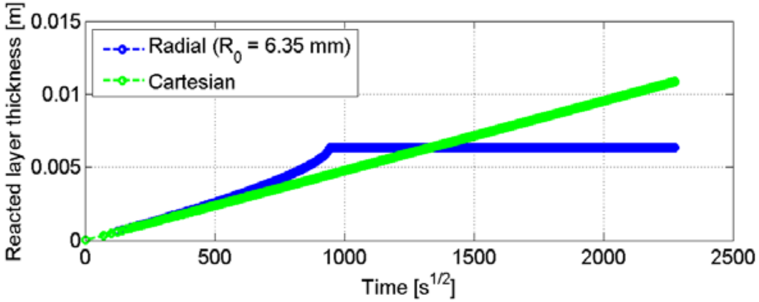
Schlumberger Carbon Services

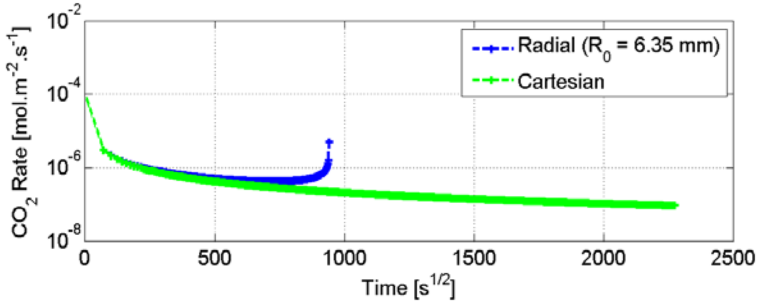
- Questions ?

D – Future experiments

- Design of experiments:
  - Initial conditions (i.e. cement composition):
    - Vary calcium reserve and tortuosity independently
  - Boundary Conditions:
    - Use only wet CO_2 for closed system:
    - Vary Aq{Ca} and Aq{CO_2}
  - Geometry:
    - 1 D Cartesian (and not radial):



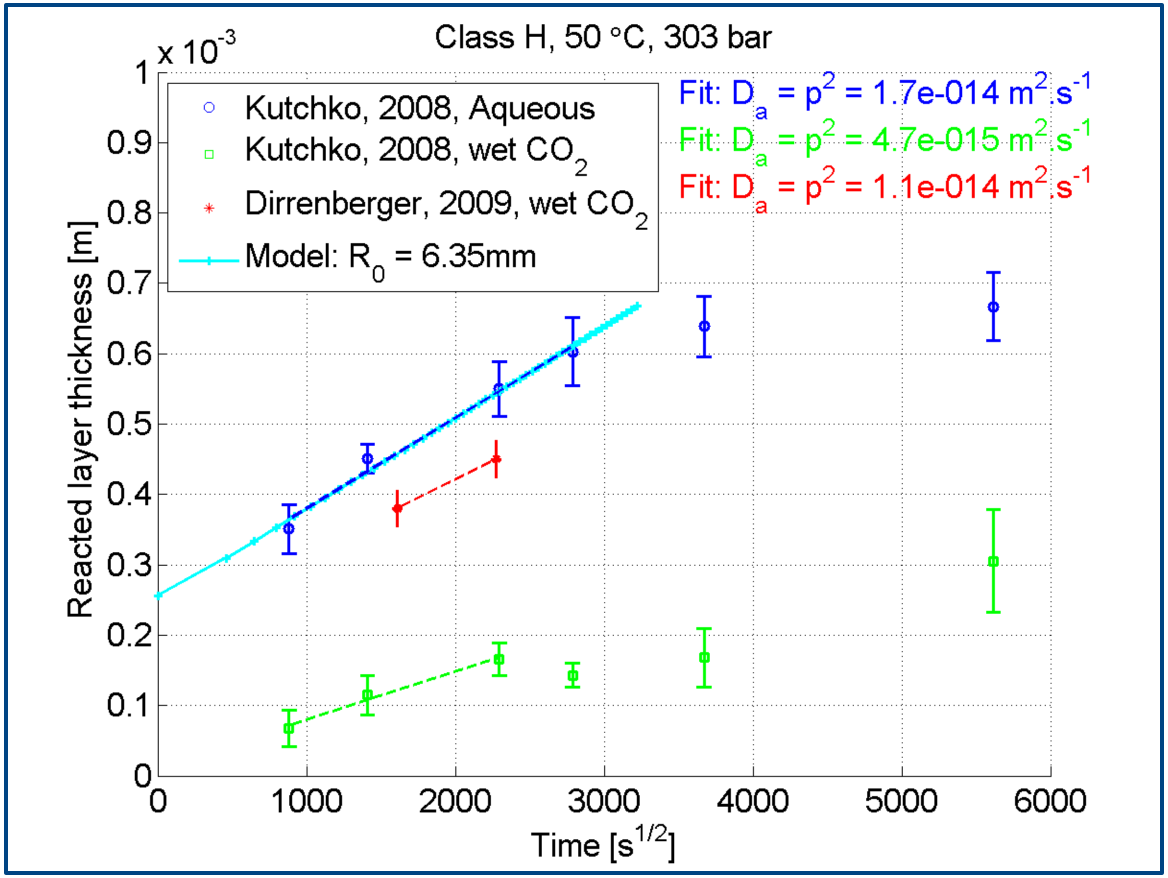




- Quantitative and local measurements:
  - Amount of CaCO3 formed
  - Effective diffusion coefficients

Class G/H, 40/50 C, 280/300 bars, water

- Experimental results:



6th Wellbore Integrity Network Meeting, The Hague, April 29-30, 2010

Performance of Portland Cement Systems in HTHP CO_2 Environment

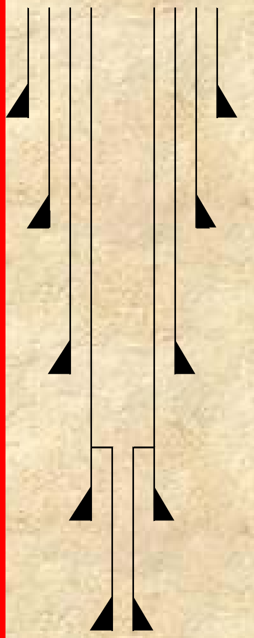
Andreas Brandl [1], Ragheb Dajani [2]

[1]BJ Services Company, [2]HESS Corporation

HTHP project - Cementing Challenges

- Narrow pore pressure – frac gradient windows
- 50% CO_2 at T>300 F, P>3,000 psi
- High ΔP & ΔT
- Offshore well

Casing (in)	TVD (ft)	Pore Pressure (ppg)	Frac Grad (ppg)	BHST (ºF)	ΔT Prod (ºF)	ΔT Prod TOC (ºF)	ΔP Prod (psi)	Max.% CO_2
26	1200	8.0	12.3	112	180	111.2	0	5
18.625	4230	8.7	14.0	200	121	188	2050	8
13.375	7200	13.5	15.5	275	88.2	124.1	3370	50
9.625	8284	15.8	18.5	315	73.4	88.8	-3731	50
4.5	10450	17.5	19.2	375	5	86.2	-9400	50



Long Term Zonal Isolation

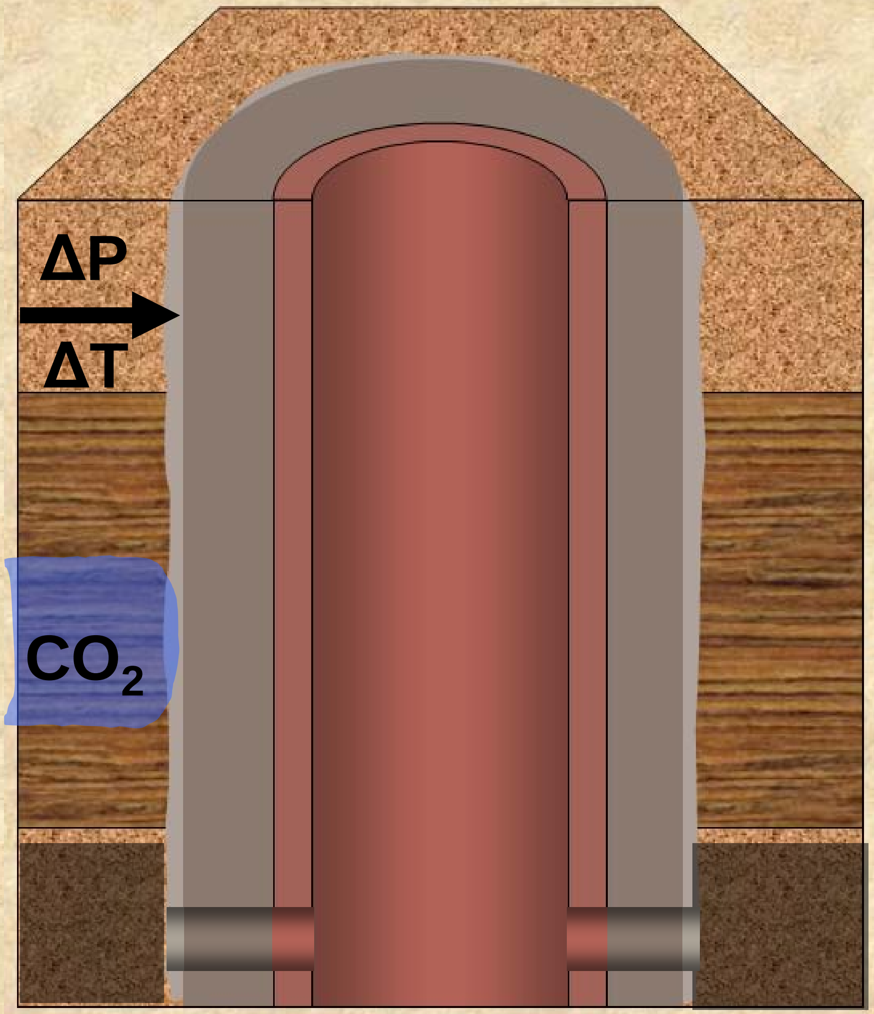
1. Follow best practices with a Portland cement system

   (reliable, field proven & practical)

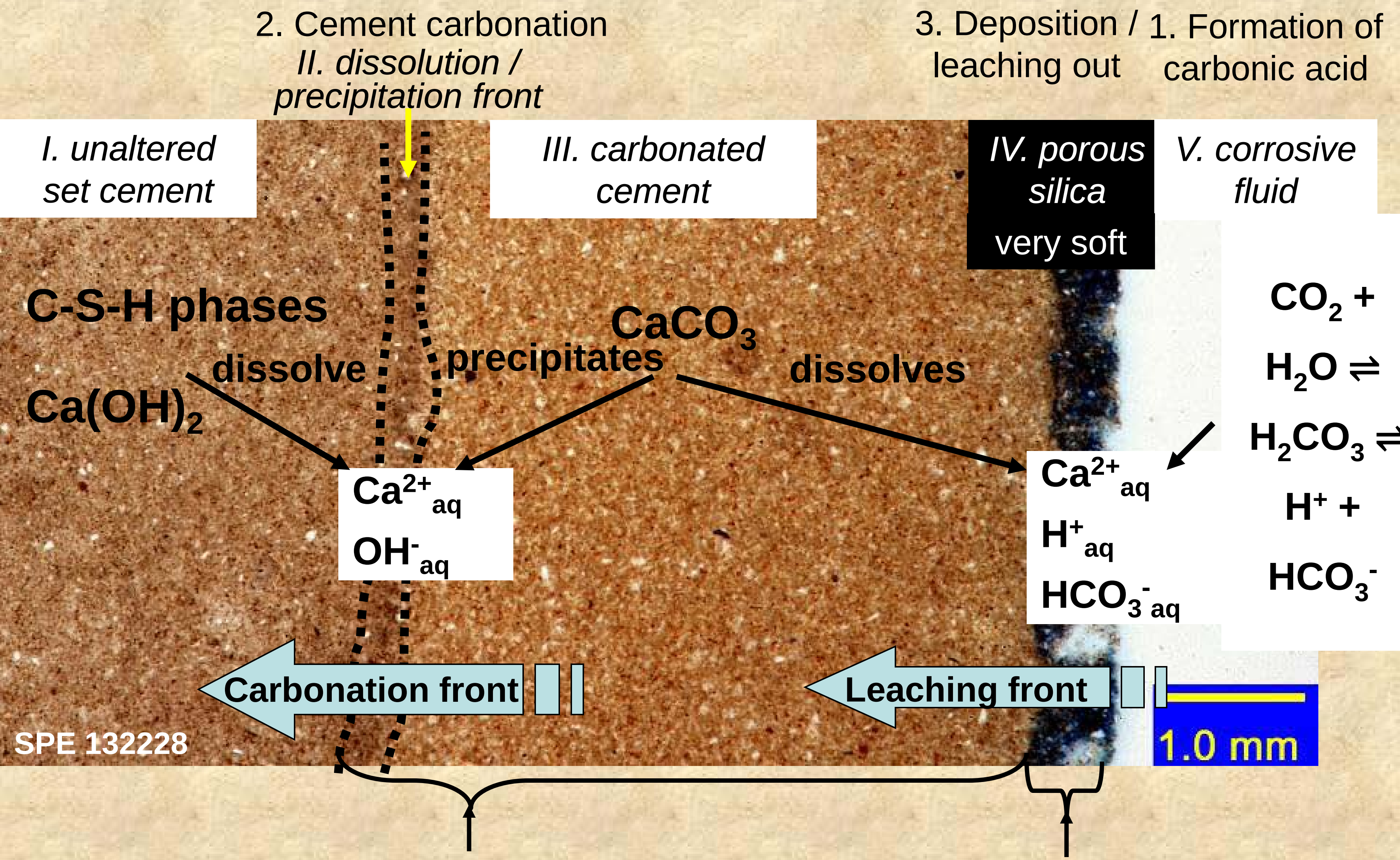
2. Good cement bonding

3. Design a cement system:
   - with suitable mechanical properties
   - preventing strength retrogression
   - mitigating corrosive attacks

     (Mg^{2+}, SO_4^{2-}, H_2S, CO_2 …)



CO_2 Attack: Cement Thin Section



Initial sealing by carbonation is followed by detrimental leaching

Results from Field Studies

- Portland cement degradation in a well due to CO_2 is a very slow process (<10 mm / 30 yrs) J.W. Carey et al. 2007

- Degradation mainly occurs along existing or induced pathways B. Kutchko et al. 2009

$\Rightarrow$ Defects, existing annuli & leakage pathways accelerate the CO_2 attack

- Pozzolan/Portland cement systems inhibit CO_2 migration after carbonation W. Crow et al. 2009

$\Rightarrow$ Cements ability to resist CO_2 attack is secondary to the ability to obtain a good initial cement bond

http://www.ieaghg.org/docs/monitoring/2009_4_secured_summary_only.pdf

Tested Portland Cement Systems

cement system	"pozzolan"	"conventional"
base blend	class G +silica flour +pozzolan	class G +35% bwoc silica flour
slurry density (lbs/gal)	15.0	15.0
water:solid (wt/wt)	0.55	0.72
portlandite (wt%)	not detected	not detected
Oxidic composition of set cement systems (calculated from EDS analyses)		
CaO (wt%)	46.6	47.5
SiO_2 (wt%)	40.8	39.8
CaO/SiO_2 (mol/mol)	1.1	1.1
C (wt%)	2.4	2.3

- Comparison based on same density and same amount of formal CaO
- Sufficient silica to prevent strength retrogression (T=300 F)

CO_2 Tests

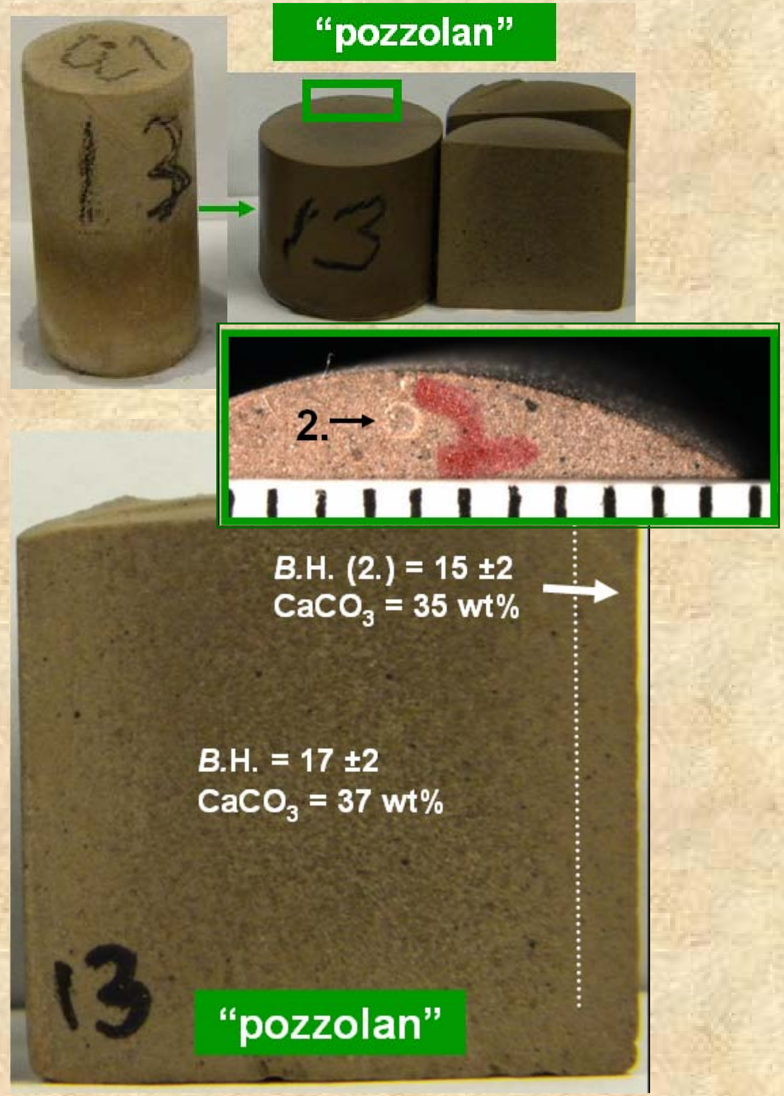
Pozzolan ⟷ **Conventional**

- **Specimens pre-cured at 3,000 psi & 300 F for 96 hrs**
- **Exposure to CO_2 loaded water at 3,000 psi & 300 °F**

HTHP curing chamber connected to a CO_2 bottle

Cement cylinders (1” dia, 2“ length) exposed to CO_2 for up to 6 months

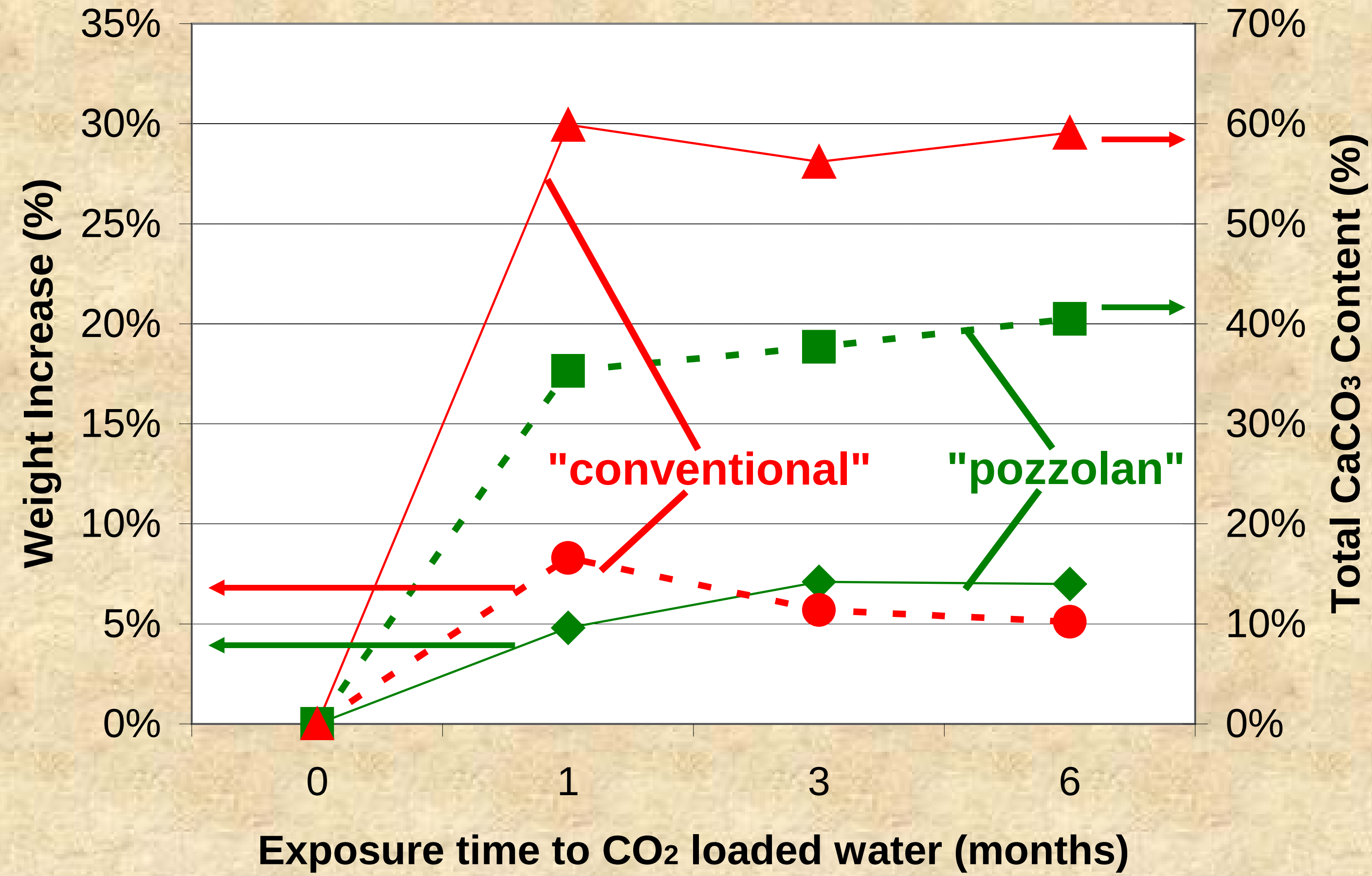
After 1. month exposure to CO_2



- No more alkalinity left (CO_2 diffusion completed)
- **"conventional": stronger carbonation & soft brownish rim**

Exposed to CO_2 over 6 months

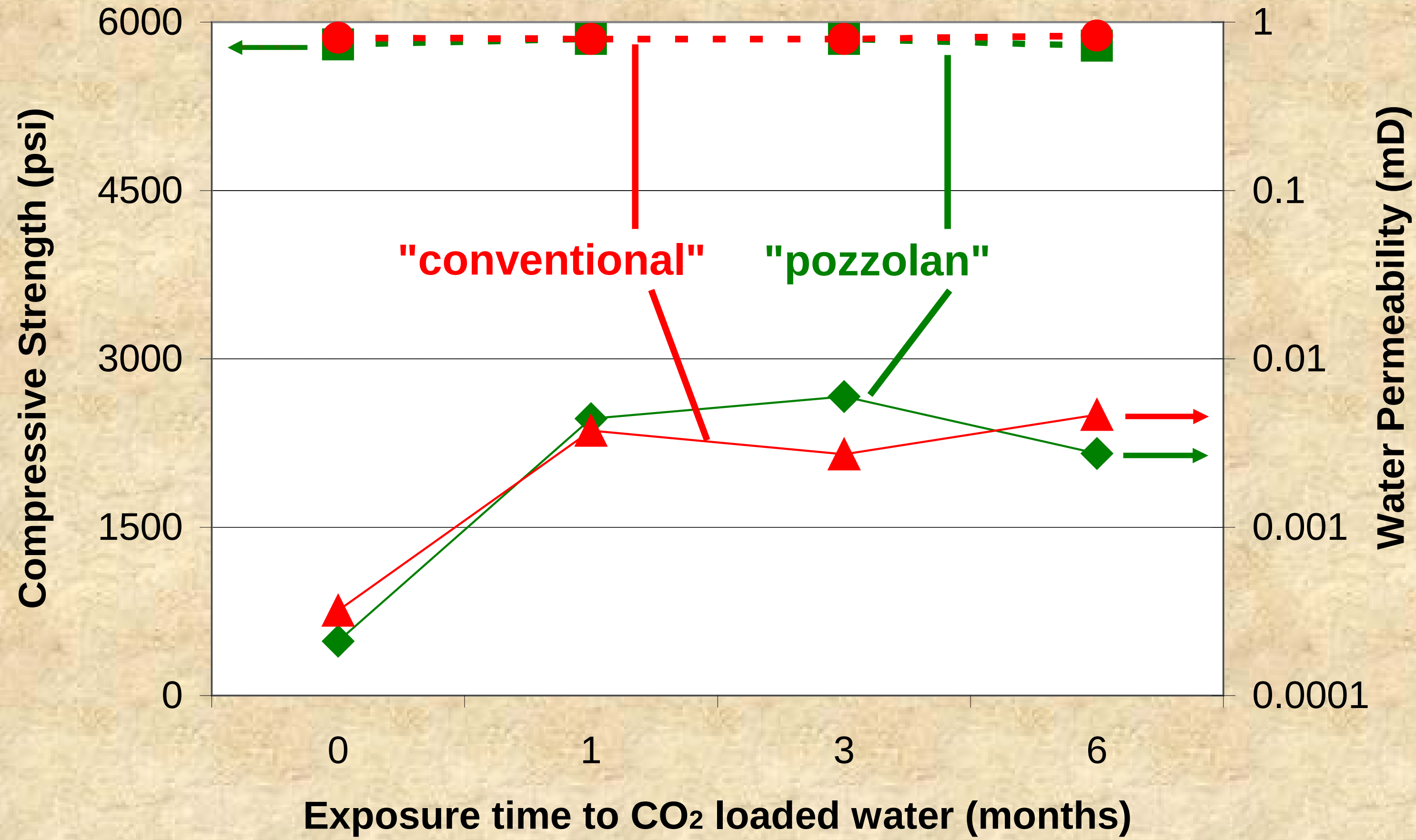
(300 F, 3,000 psi)



- Increase in weight **(“pozzolan”: 4-7%**, **“conventional”:8-5%**)
- Less carbonation for **“pozzolan”: 35-40%** vs. **“conventional”: 56-60%**

Exposed to CO_2 over 6 months

(300 F, 3,000 psi)



- High compressive strength (>5,000 psi)
- Sufficient low water permeability (<0.01 mD)

Effect of CO_2 on Cements' Mechanical Properties

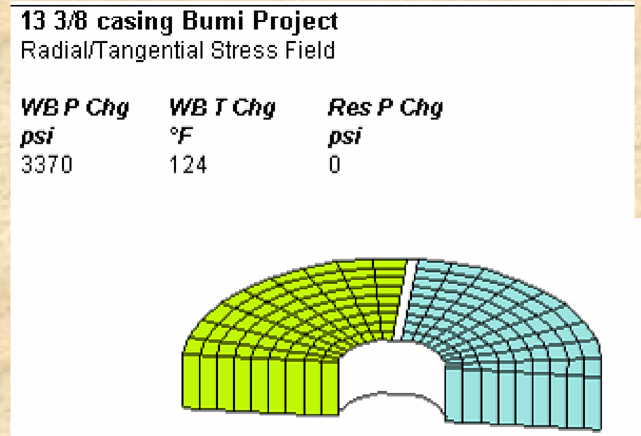
Cement system	density (ppg)	Young's modulus (Mpsi) Confining Stress: 1000 psi	Poisson's ratio Confining Stress: 1000 psi	Compressive strength (psi) Confined	Tensile strength (psi) Unconfined
After 96 hrs curing at 3,000 psi / 300 F (before CO_2 exposure)					
Pozzolan	15.0	1.52	0.32	>5,800	354
Conventional	15.0	2.07	0.33	>5,860	258
After 30 days exposure to CO_2 at 3,000 psi / 300 F (high carbonation)					
Pozzolan	16.1	0.85	0.26	>5,850	468
Conventional	16.5	1.17	0.23	>5,850	438

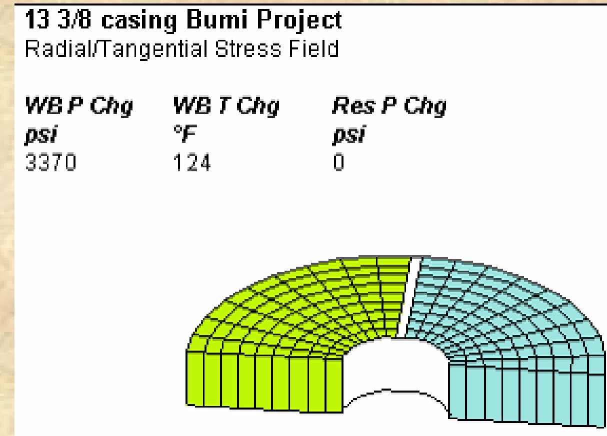
Numerical Wellbore Stress Model

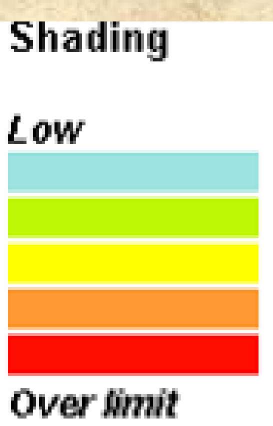
Pozzolan

Conventional

Before exposure to CO_2

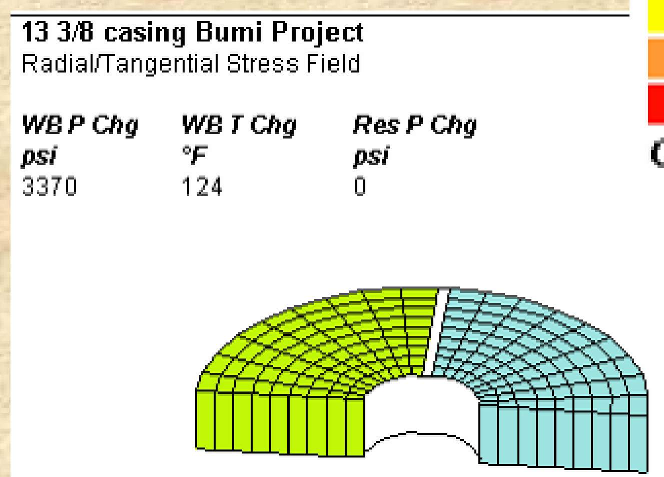


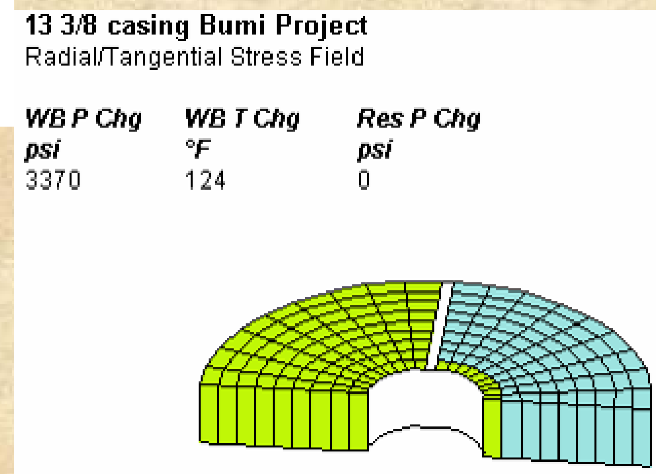




Portion of cement strength
<25%
25-50%
50-75%
75-100%
>100%

After exposure to CO_2



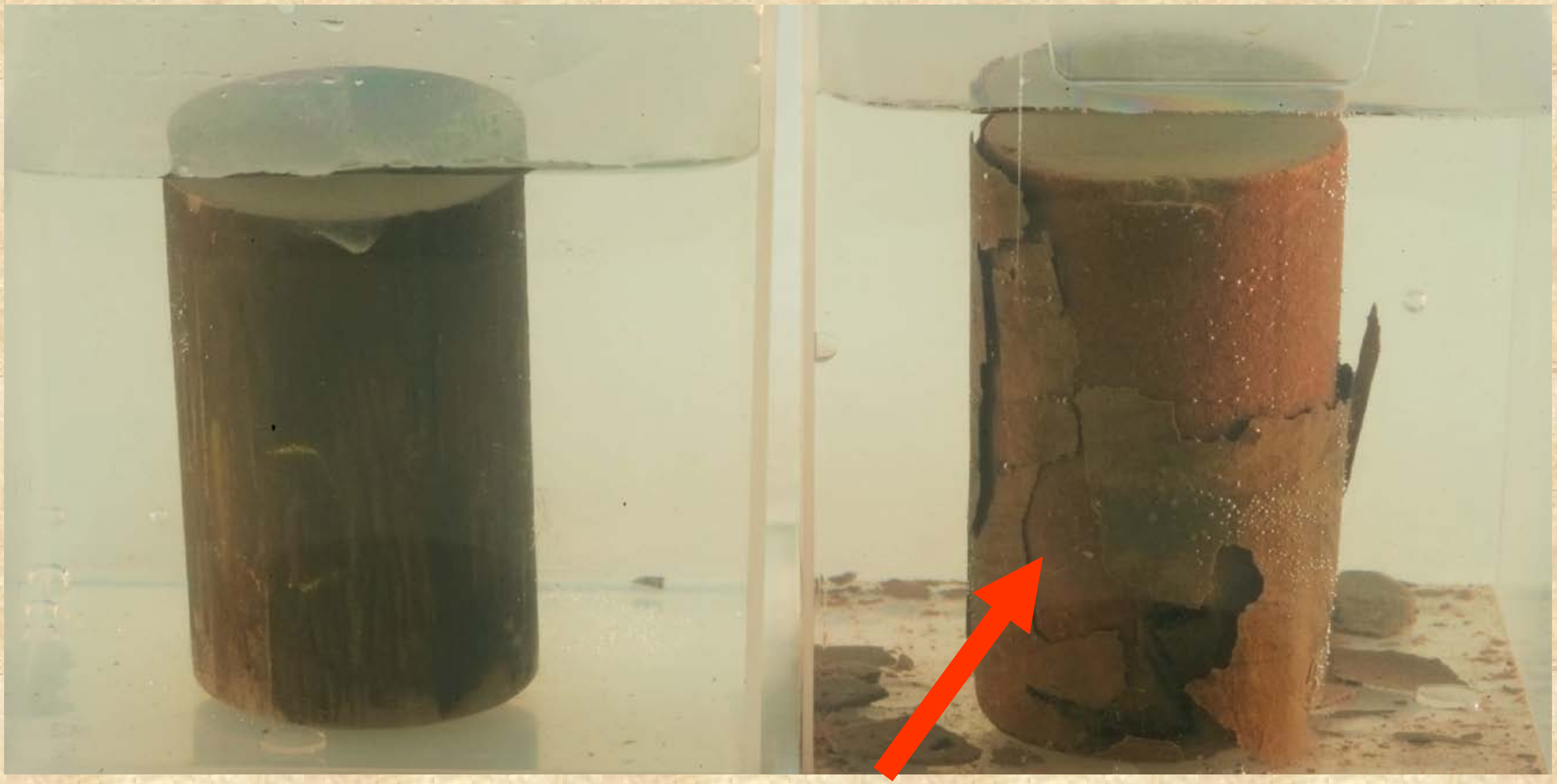


Systems were designed to pass the model withstanding ΔT and Δp

After 6 months exposure to CO_2

Pozzolan

Conventional

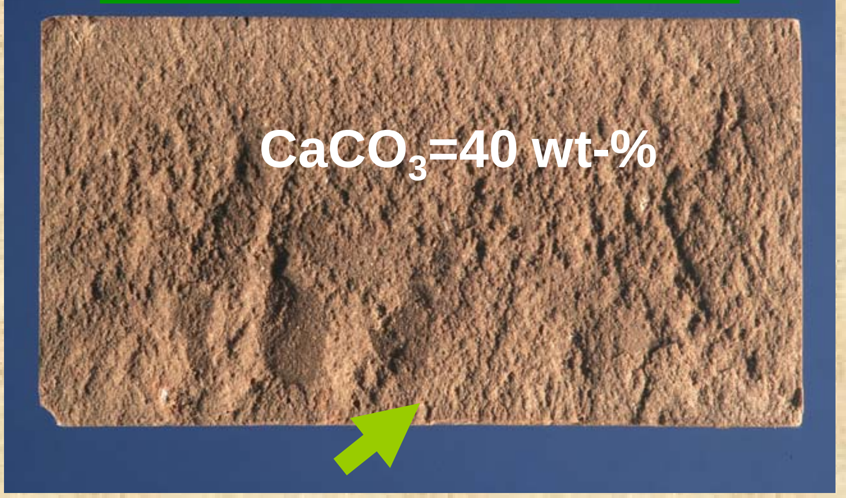


Cement specimen flaked off (diameter Δ=-0.6 mm)

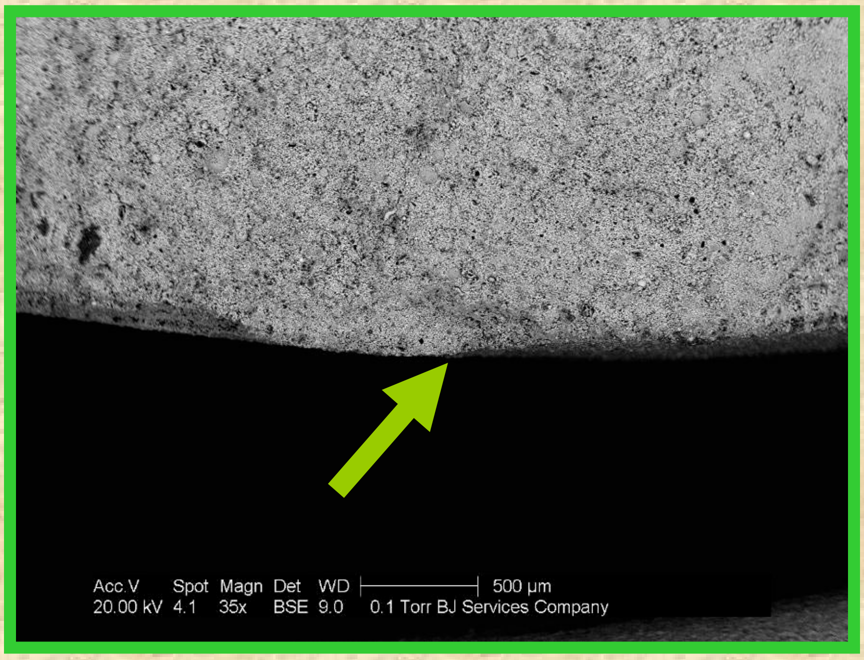
Cement bond failure (migration pathways) =>loss of zonal isolation

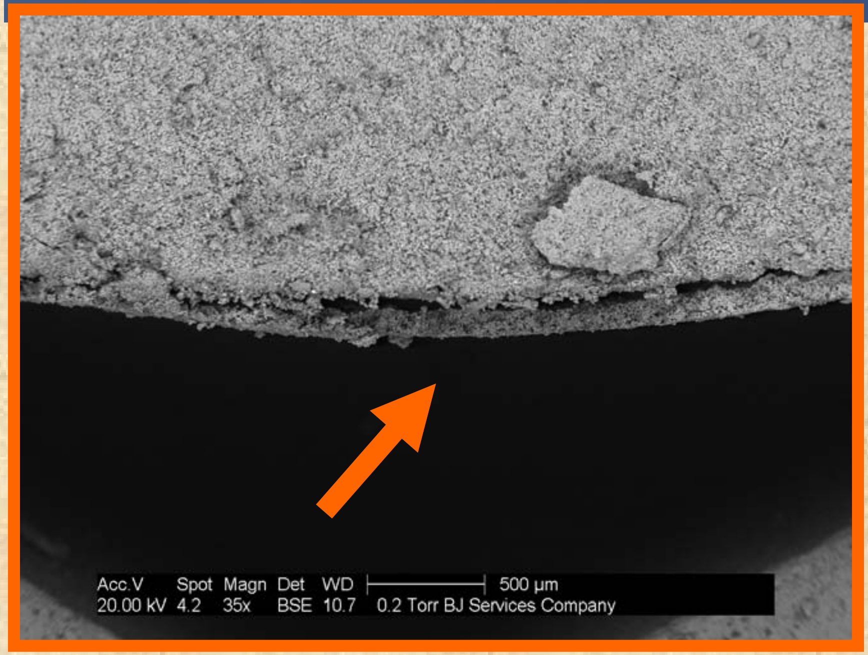
After 6 months exposure to CO_2

Pozzolan



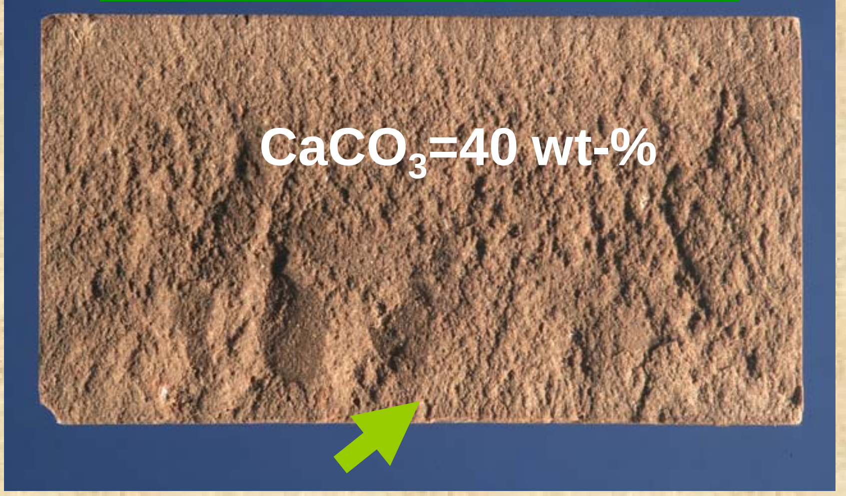
Conventional

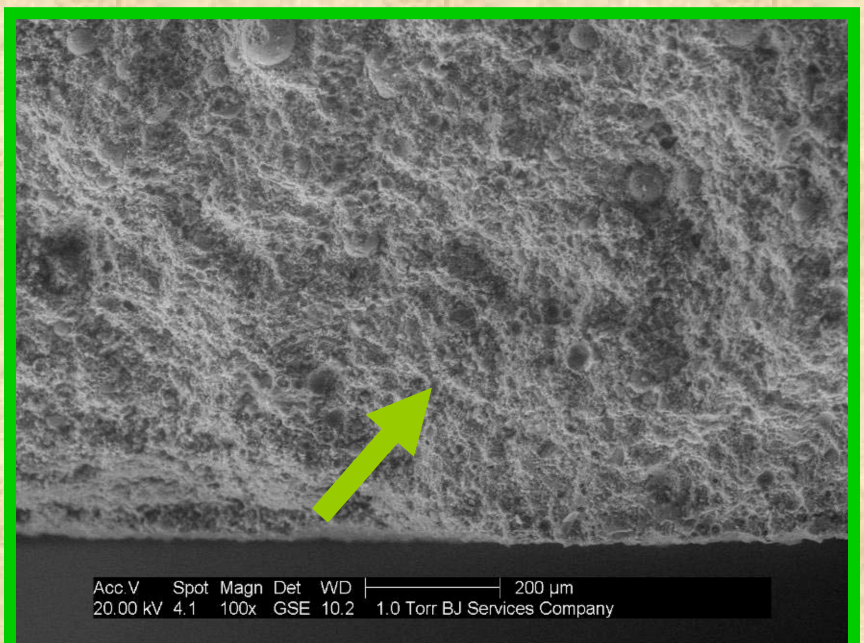




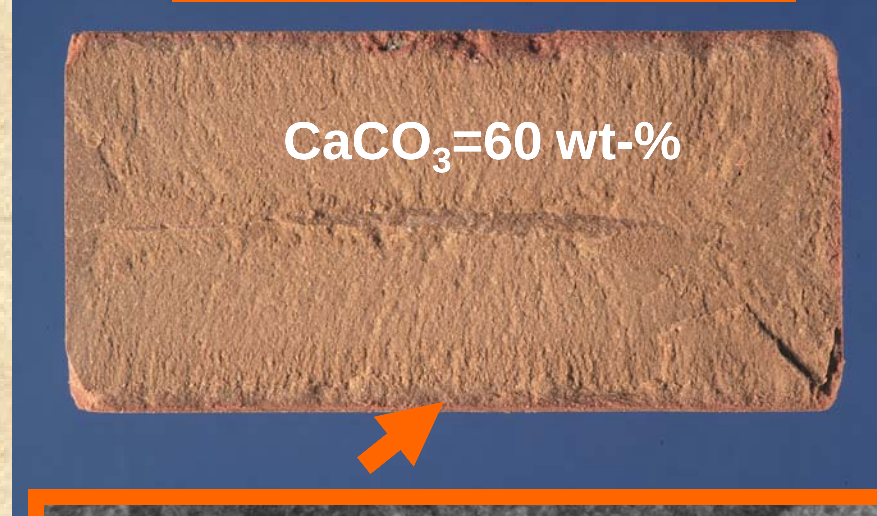
After 6 months exposure to CO_2

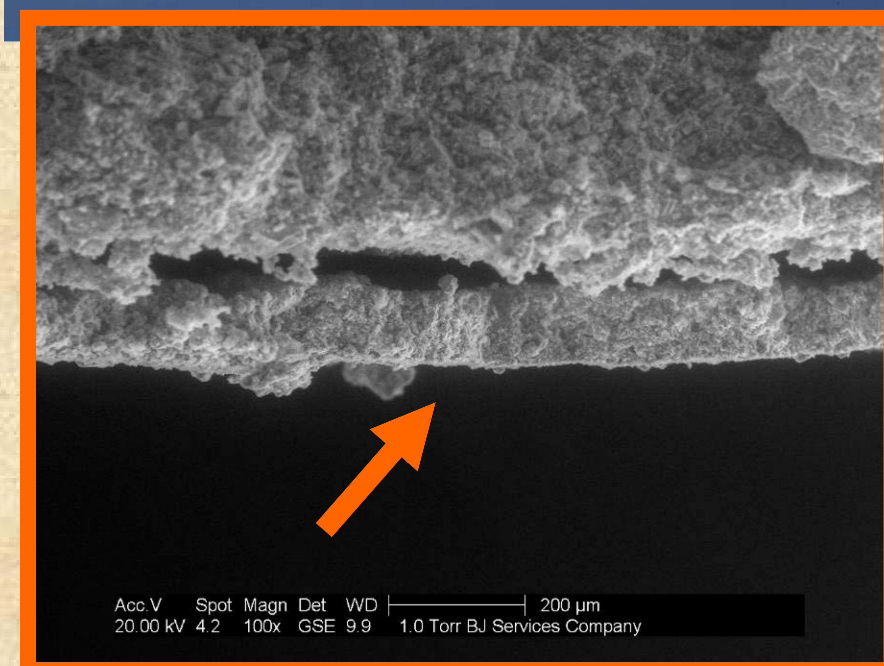
Pozzolan



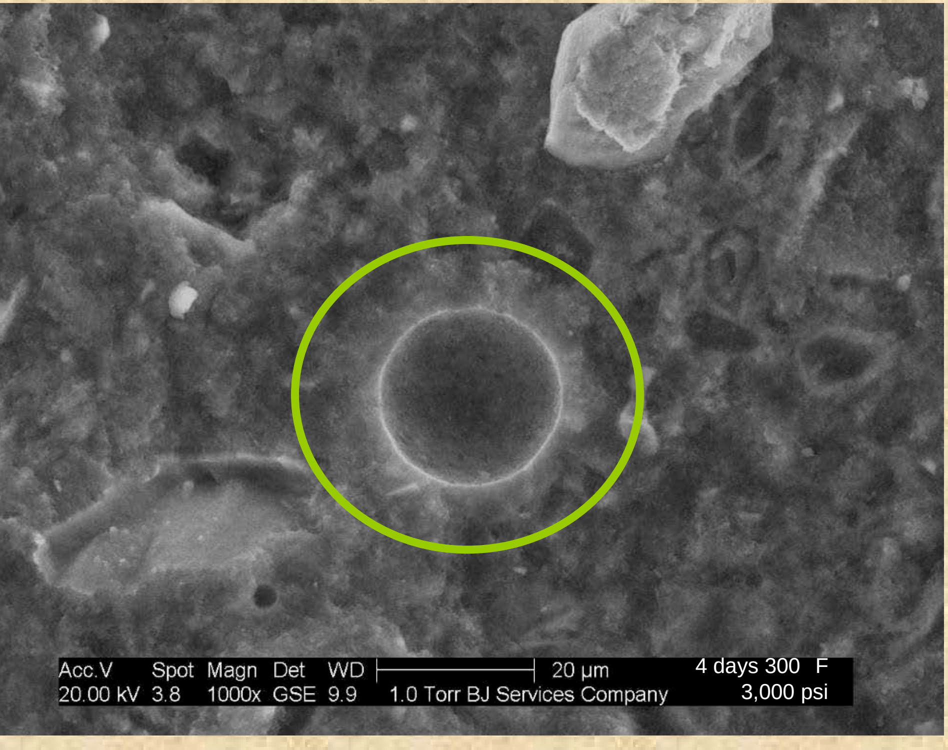


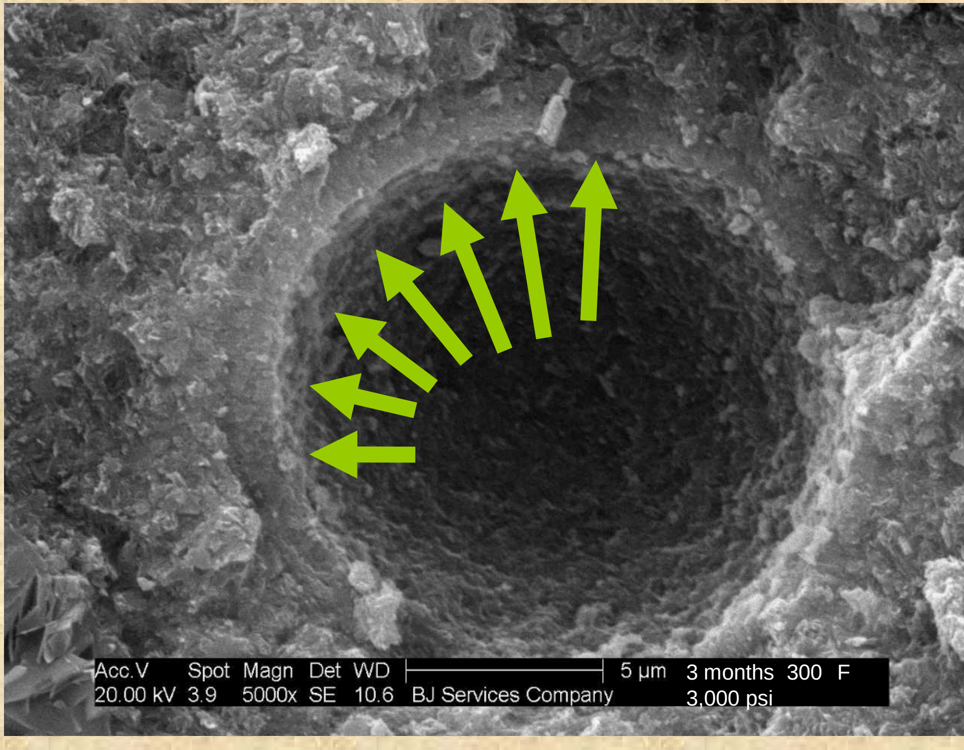
Conventional





Effect of Pozzolans





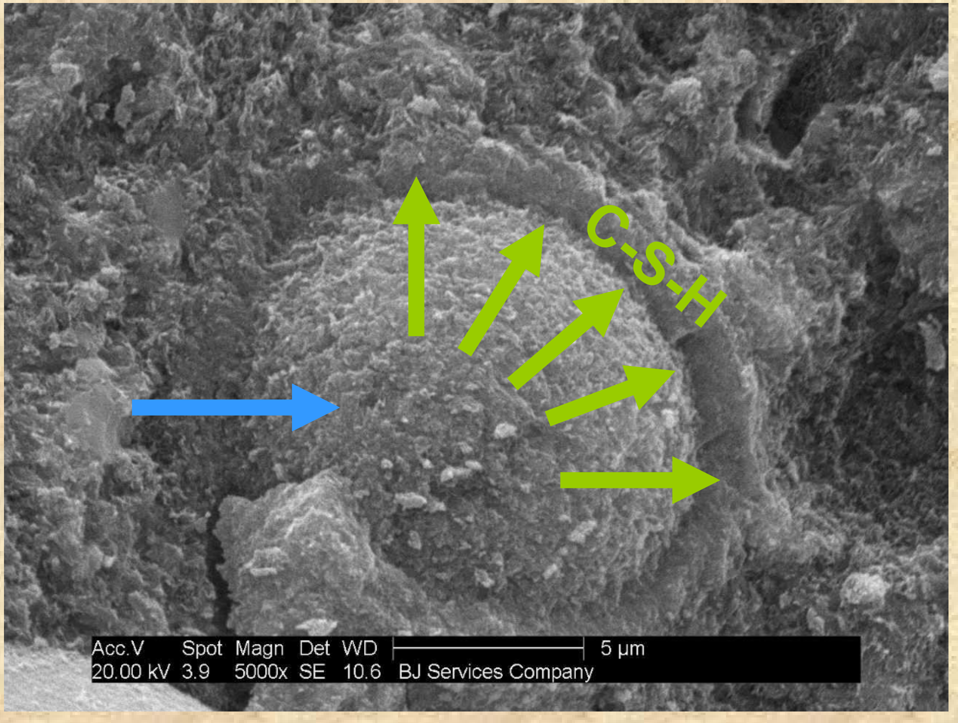
Promote a sheath of densified C-S-H phases

=> compact cement matrix

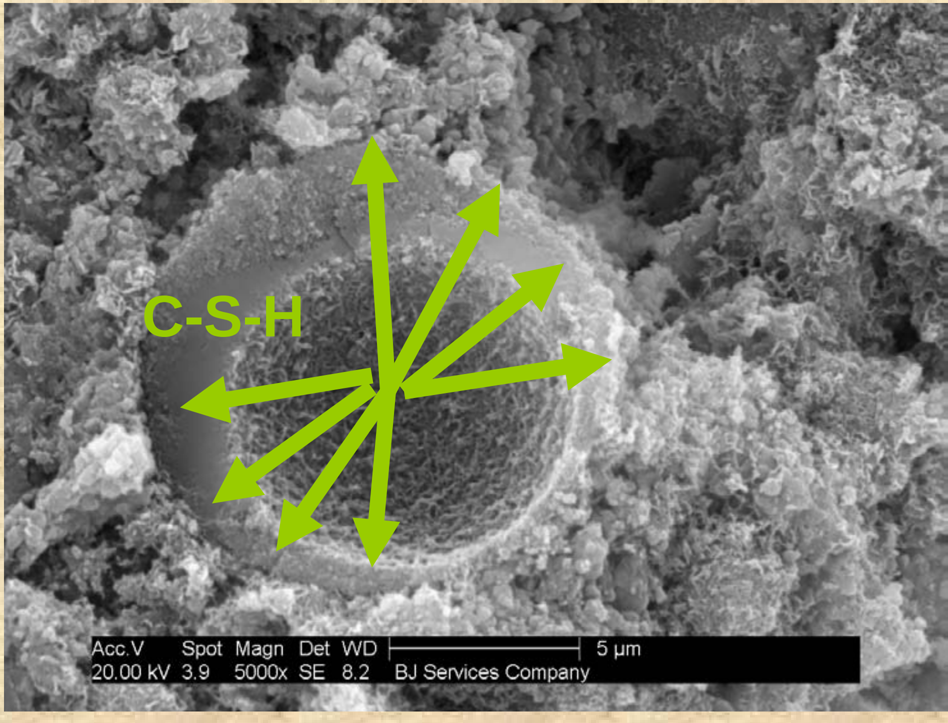
=> higher strength & durability

Effect of Pozzolans

After 96 hrs / before CO_2 exposure



After 6 months CO_2 exposure



Dublex film (0.5 µm) out of C-S-H phases on the fly ash surface (Huettl, 2000)

Sheath of densified C-S-H phases epitaxially grown on the **dublex film**

Sheath of densified C-S-H phases remains unaffected after CO_2 exposure

Summary

• Portland cement system can be a practical solution for CO_2 wells:
  Utmost importance is following best cementing practices

• Mechanical properties are **not** negatively affected by CO_2

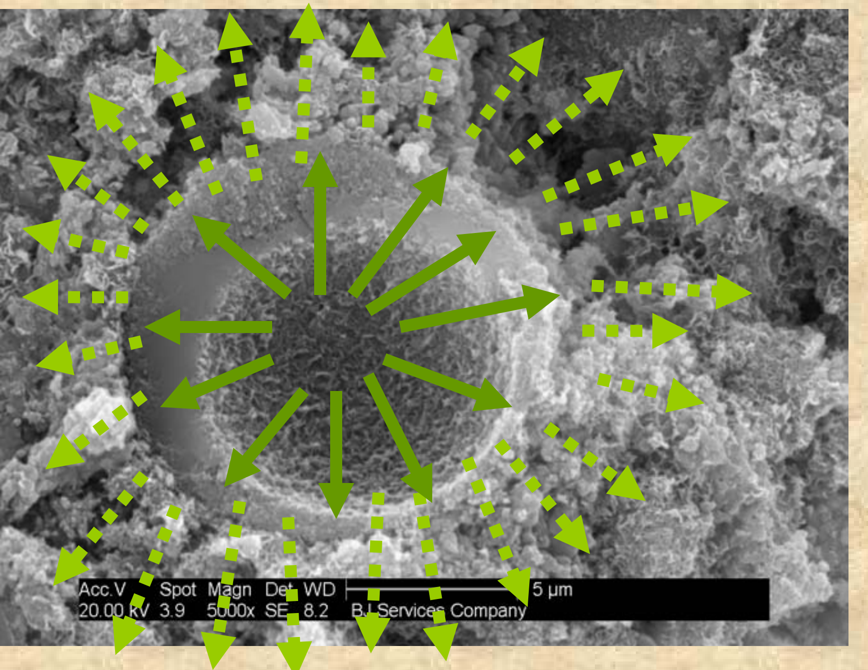
• “Pozzolan” showed improved performance vs. “Conventional” system:
  - => Less carbonation
  - => No loss of integrity (low perm, high c.s.)
  - => No severe flaking causing loss of zonal isolation

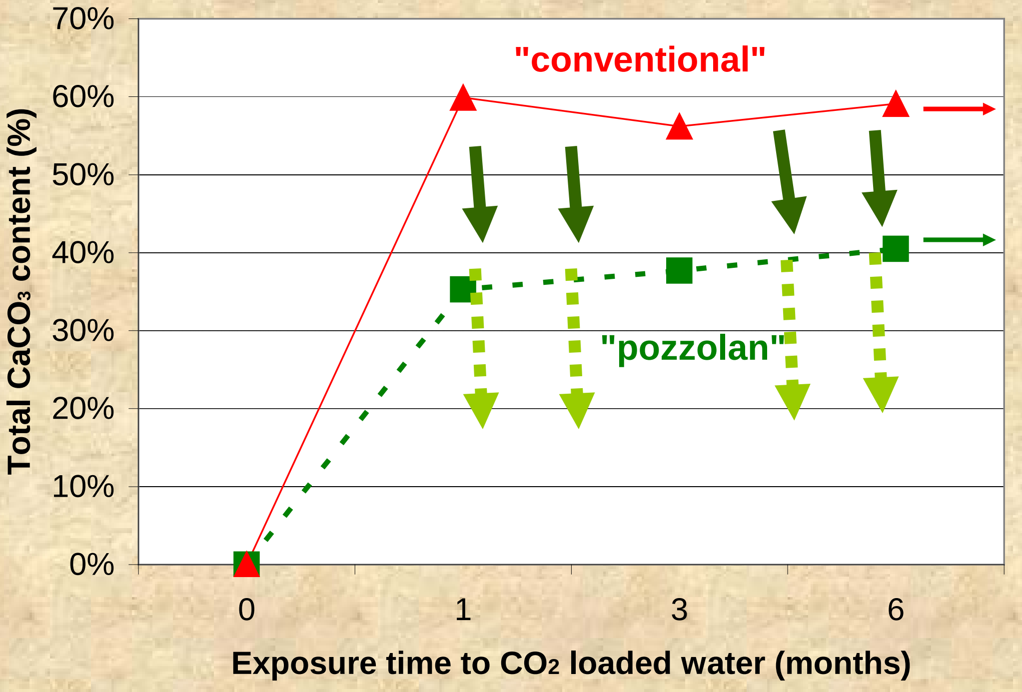
• HTHP tests as a model to predict long terms effects of CO_2?

Outlook

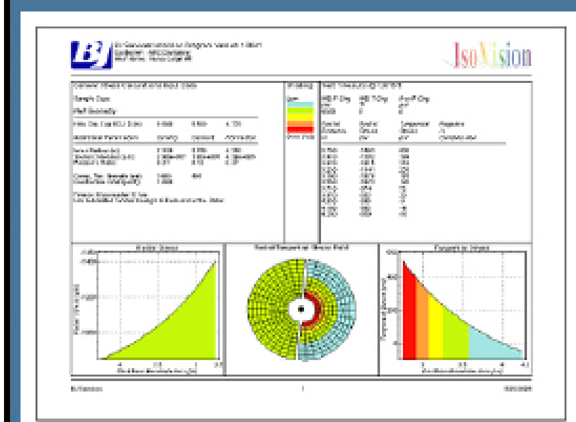
- Better understanding of the role of pozzolans in cement
- Goal: **Expand the growth of densified C-S-H phases** to reduce the total carbonation even further

Pozzolan





Overview



BJ IsoVision™

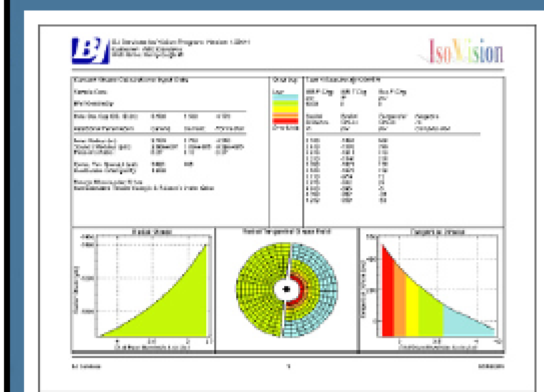
- Features:
  - Bilinear elastic model
  - Approximates the initial state of wellbore stresses
  - Predicts the magnitude of induced stress
  - Considers other operational imposed stresses

- 07 Set for Life V3.pdf - Adobe Reader

ocument Tools Window Help

10 / 11 129% Find

Overview



BJ IsoVision™

BJ IsoVision™ Wellbore Model has been developed to quantify induced stresses on cement sheath, using same methods as those employed in the area of rock mechanics.

Most sheath failures occur at the casing-cement interface due to tangential stress in excess of the cement's tensile strength.

BJ IsoVision™ determines if a specific cement system is fit for its intended purpose.

Andreas B... 4 Firefox 2 Micro... 4 Wind... ENG202 ...

Numerical Wellbore Stress Model

Cement Stress Calculations Input Data

"Pozzolan" cement system @ 15.0ppg after 96 hrs cured @ 300 F / 3,000 psi

Well Geometry

Hole Dia, Csg OD, ID (in):	17.500	13.375	12.347

Additional Parameters	***Casing***	***Cement***	***Formation***
Inner Radius (in):	6.174	6.688	8.750
Young's Modulus (psi):	2.90e+007	1.52e+006	3.22e+006
Poisson's Ratio:	0.27	0.32	0.08

Cement Comp, Ten Strength (psi): 5800 354
Overburden Grad (psi/ft): 1.000

Time to 50 psi under 12 hrs
Use Estimated Tensile Young's & Poisson's in the Calcs

Shading

Low

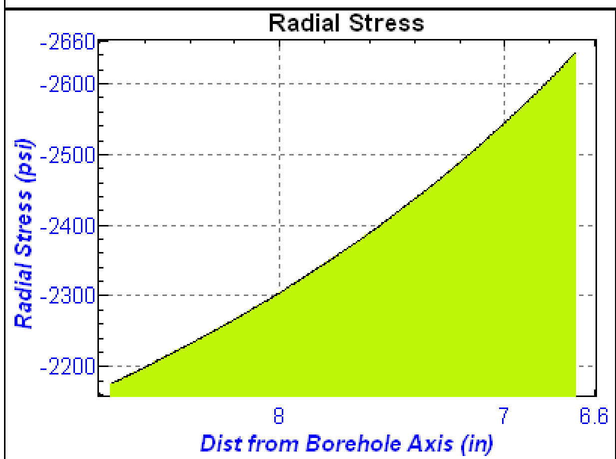
Over limit

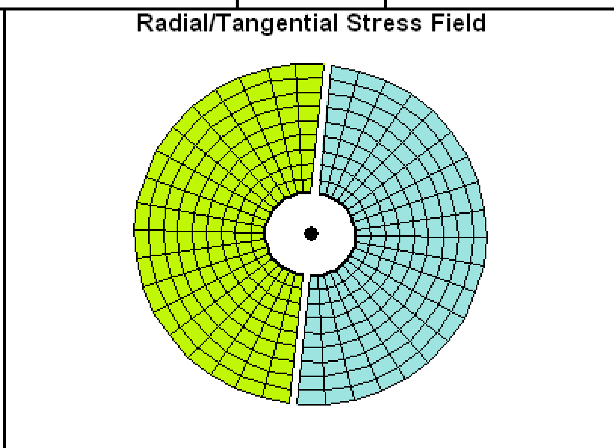
13 3/8 casing Bumi Project Results @ 6000 ft

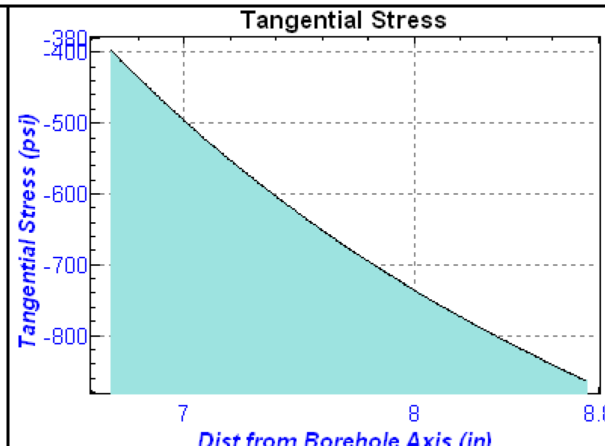
WB P Chg psi	*WB T Chg °F*	*Res P Chg psi*
3370	124	0

Radial Distance in	*Radial Stress psi*	*Tangential Stress psi*
6.688	-2643	-398
6.898	-2575	-465
7.108	-2514	-527
7.318	-2458	-583
7.528	-2406	-634
7.738	-2359	-682
7.948	-2315	-726
8.158	-2275	-766
8.368	-2237	-803
8.578	-2203	-838
8.750	-2176	-865

Negative is compression







Test methods

Young’s modulus, Poisson’s ratio, and compressive strength were determined from uni-axial and tri-axial stress-strain tests performed on cement cylinders under a confining pressure of 1,000 psi. Testing procedures and apparatus closely follow ASTM D 7012-07 “Standard Test Method for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures” recommended practices.

Tensile strength data were determined from a direct unixial tensile strength method according to ASTM Standard C-307 tensile strength using briquette specimens “Dog Bones” and a United press model STM-20k.

Micro indentation: *Brinell* hardness (*B*.H.) was determined by forcing a hard steel sphere of a specified diameter under a specified load into the surface of a material and measuring the diameter of the indentation left after the test. *Brinell* hardness is obtained by dividing the load used, in kilograms, by the actual surface area of the indentation, in square millimeters. The result is a pressure measurement, but the units are rarely stated.

Test methods

Water permeability: Cement cylinders were loaded into a pre-heated (200 °F) *Hassler*-style coreholder and a confining pressure of 4,500 psi (1,500 psi net confining pressure) was applied. Using an Isco syringe pump, deionized water was injected at constant pressure into one end. Injection pressure was introduced in 500 psi increments to 3,000 psi. Water flow through the sample was monitored by volume change in a pipette.

Chemical analysis: An EDS (energy dispersive spectrometry) system from IXRF system, Inc. unit was used for all analyses. The excitation voltage on the SEM (scanning electron microscope) was 20 kV.

Quantitative determination of CaCO3: Cement specimens were dried under vaccum and ambient temperature for 5 days. The amount of lost water during the drying process was taken into account for the quantitative determination of the total CaCO3 content (sum of aragonite and calcite; vaterite was not found). Intensities were acquired using a Phillips XRG 3100 X-ray diffractometer system equipped with a diffracted-beam monochromator and MDI JADE 8 XRD pattern processing & identification software. Corundum was used as standard. Quantities were determined by X-ray powder diffraction (PXRD) using the reference intensity ratio (RIR) method.

EFFECT OF SUPERCRITICAL CO_2 ON THE MECHANICAL BEHAVIOUR AND TRANSPORT PROPERTIES OF WELLBORE CEMENT

The weakest link?

Universiteit Utrecht

EMILIA LITEANU, CHRIS SPIERS*

CO_2 storage researcher, Shell

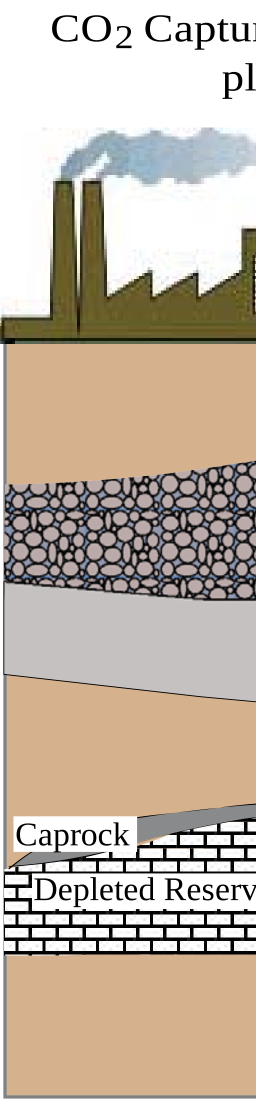
* Utrecht University, Faculty of Geosciences,HPT Lab.

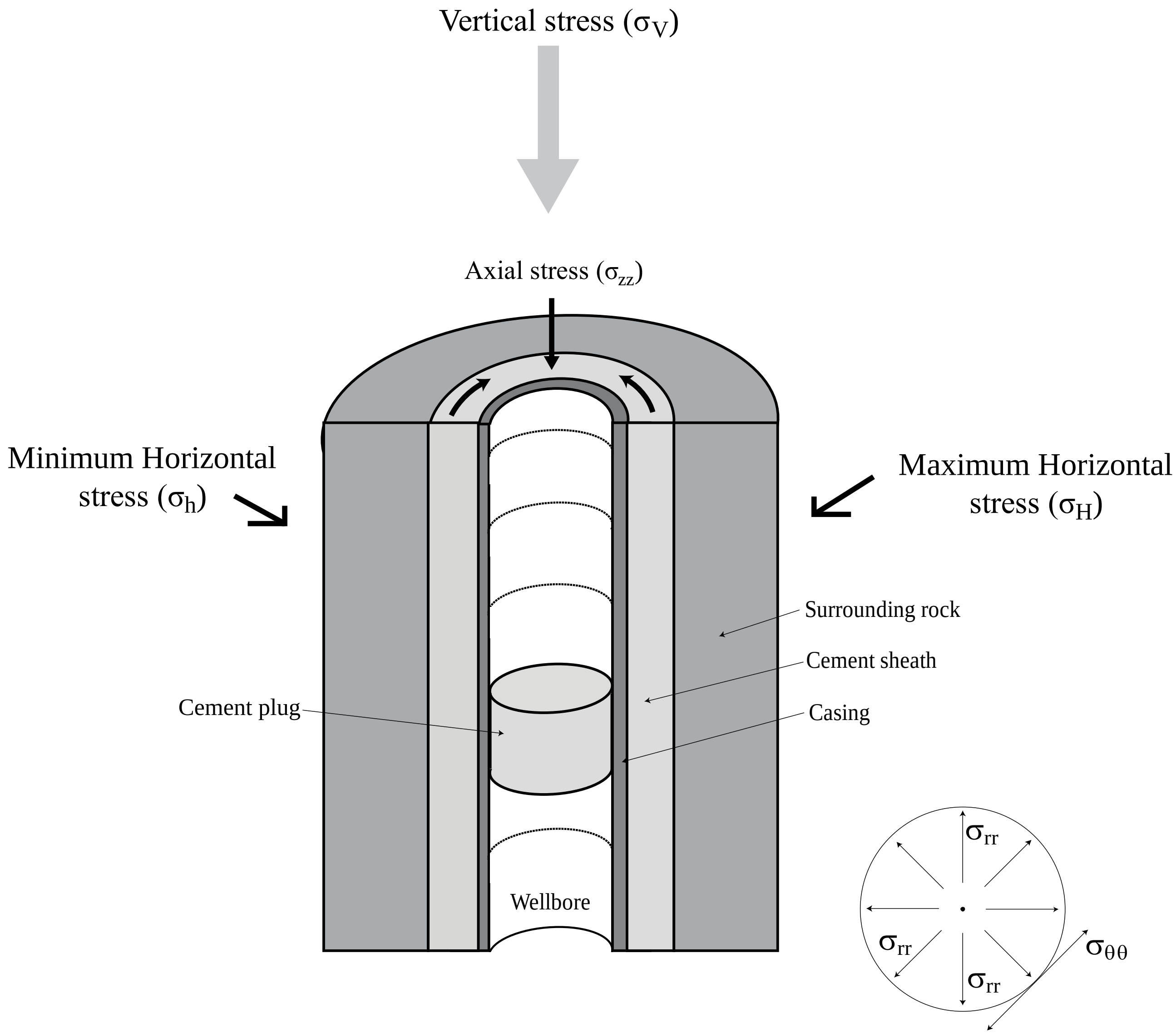
AIMS

- What is the failure behaviour of wellbore cement under reservoir conditions (i.e. 2-3 km depth)?
- Is the cement failure affected by CO_2 injection?
- How are the stress changes in the reservoir affecting the mechanical integrity of cement plugs?

- What is the effect of CO_2 on fractures present in cement sheath and cement plugs?
- Is the cement healing in the presence of supercritical CO_2?

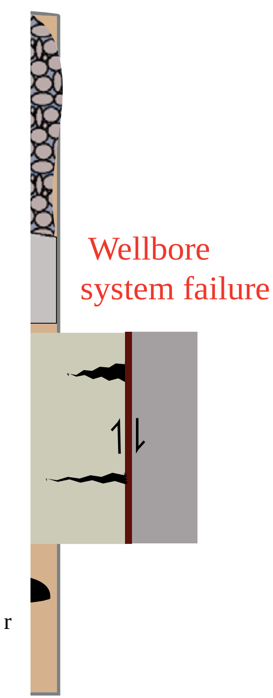
STATE OF STRESS





σ_{rr} – Radial stress
$\sigma_{\theta\theta}$ - Circumferential stress
σ_{zz} – Axial stress

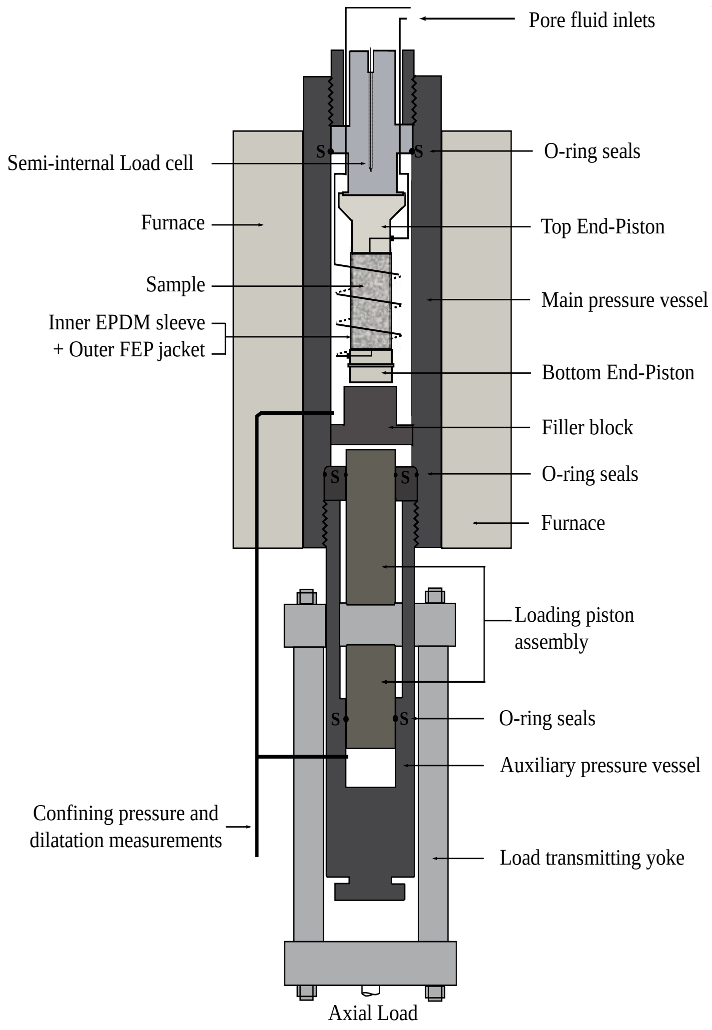
at radius r



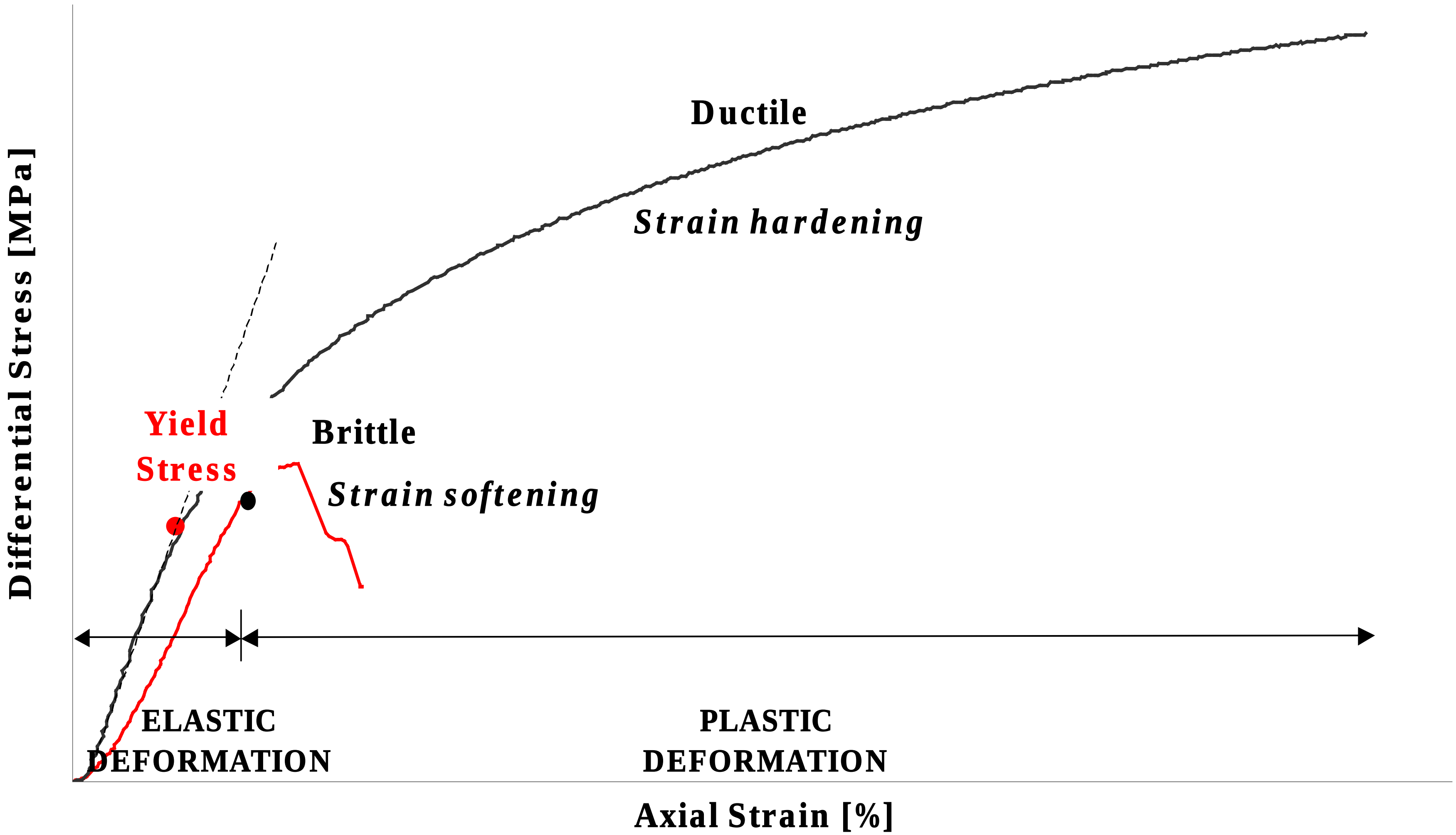
EXPERIMENTAL METHOD

Triaxial compression

- MATERIALS
  - Cylinders of Type A Portland cement
  - w:c = 0.5 (de Lier Field, Netherlands)
  - Curing time – 6 months
  - Cores = 35 X 75 mm
- EXPERIMENTAL CONDITIONS
  - Temperature = 80°C
  - P_{CO2} = 0-10 MPa
  - Constant strain rate ~ 10^{-5} s^{-1}
  - WET – Saturated solution
  - CO_2- Saturated solution



THEORETICAL BACKGROUND

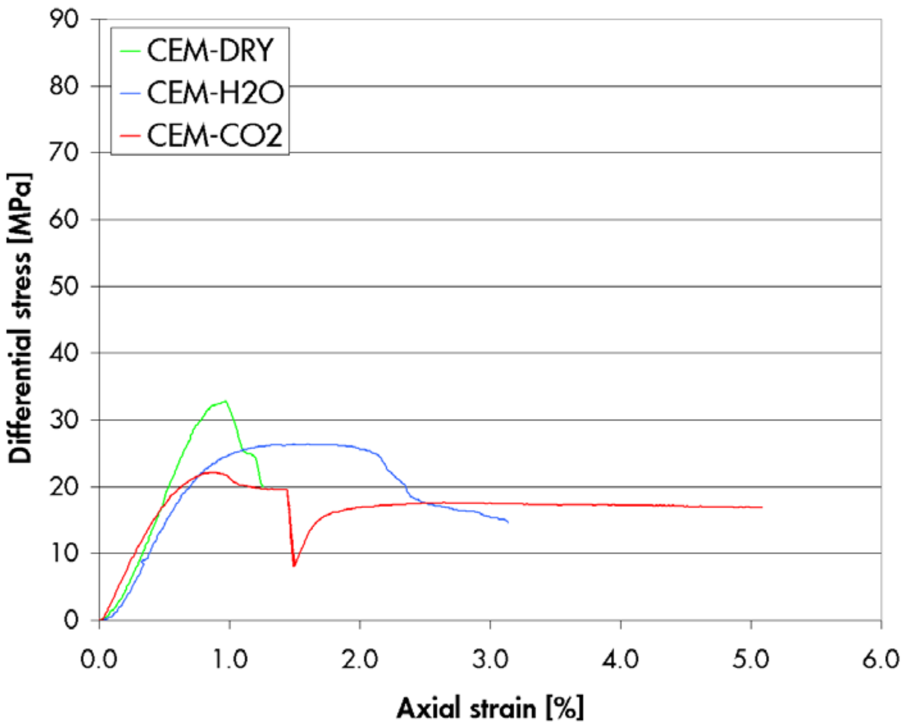


RESULTS

Mechanical data

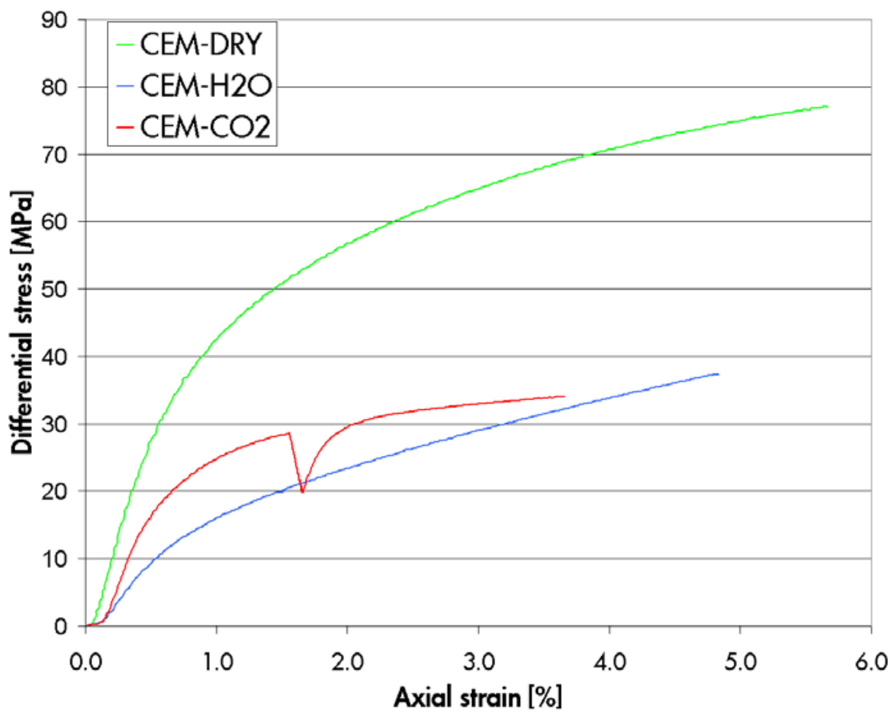
- Low effective confining pressure

1.5 MPa



- High effective confining pressure

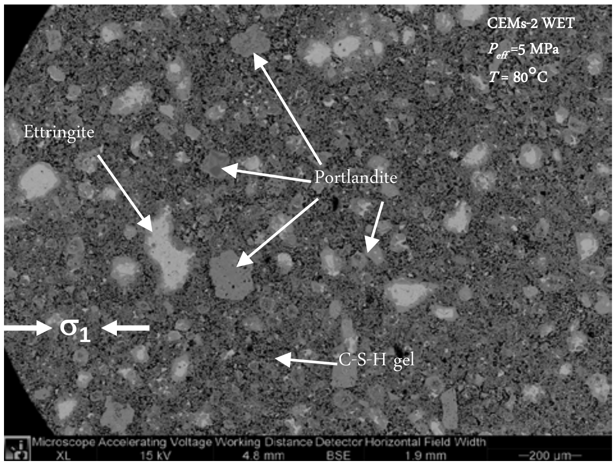
20 MPa

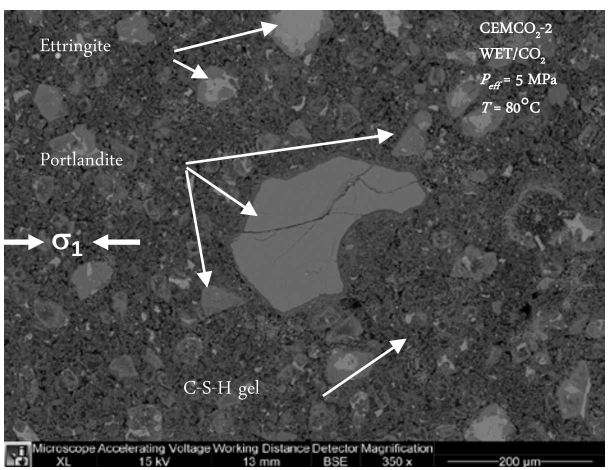


RESULTS

Micro- and macroscopic failure modes

Microstructures

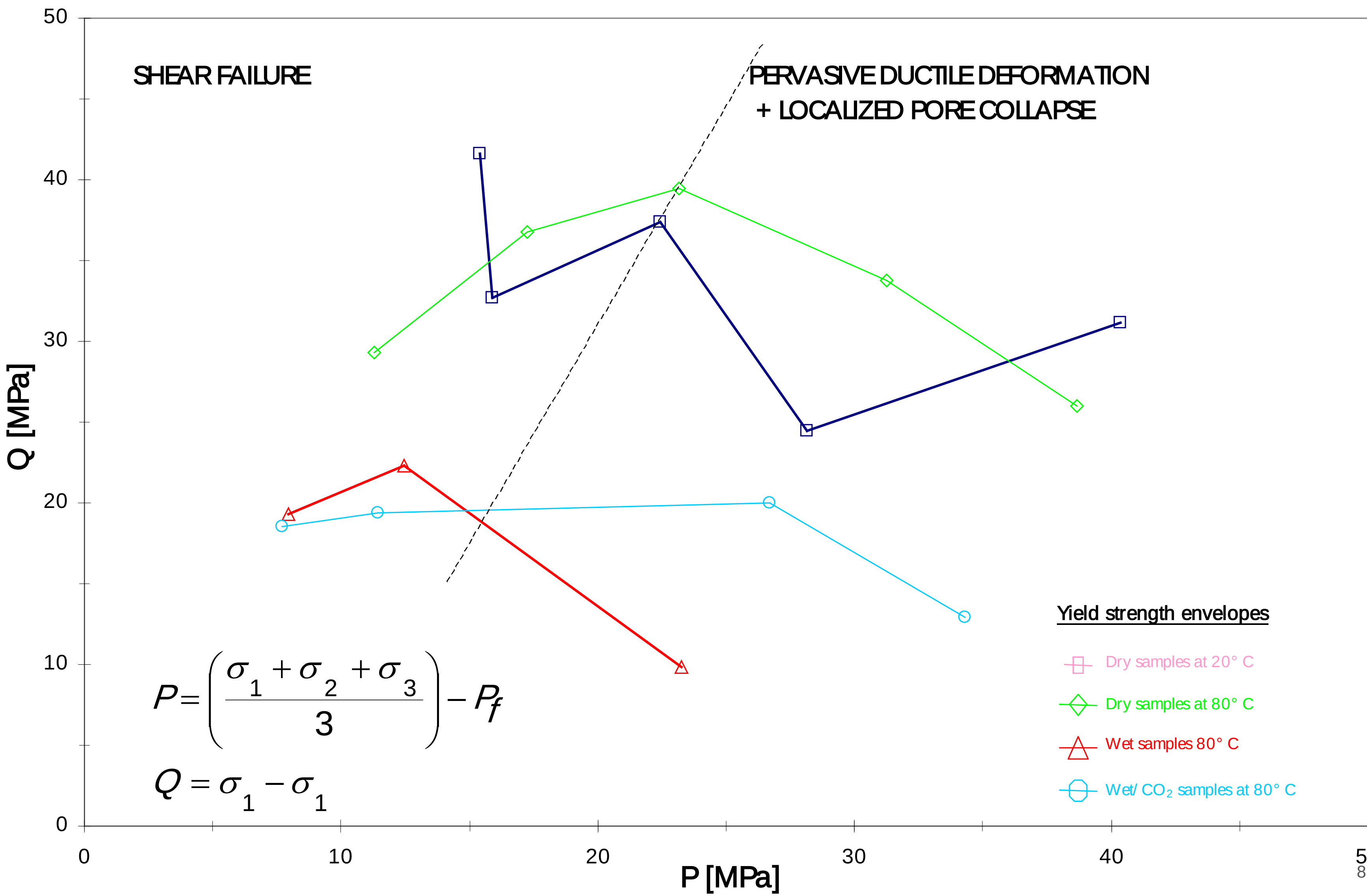




Macroscopic failure

RESULTS

Mohr-Coulomb failure envelopes



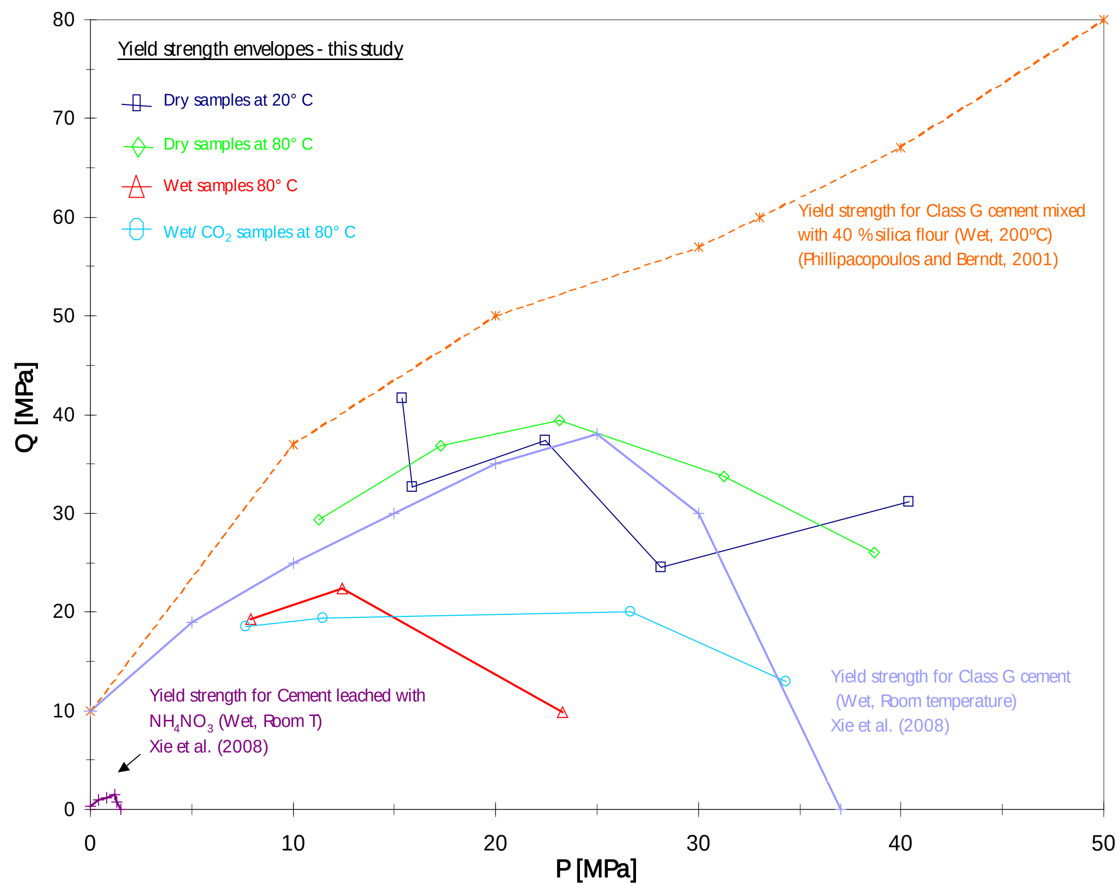
RESULTS

Comparison with previous studies

Type of experiments	Young's modulus [GPa]
Class A Cement (dry)	3.9-5.6
Class A Cement (H_2O)	1.9-2.9
Class A Cement (H_2O+CO_2)	2.6-3.4
*Class G Cement (H_2O)	10
+Class A Cement	6

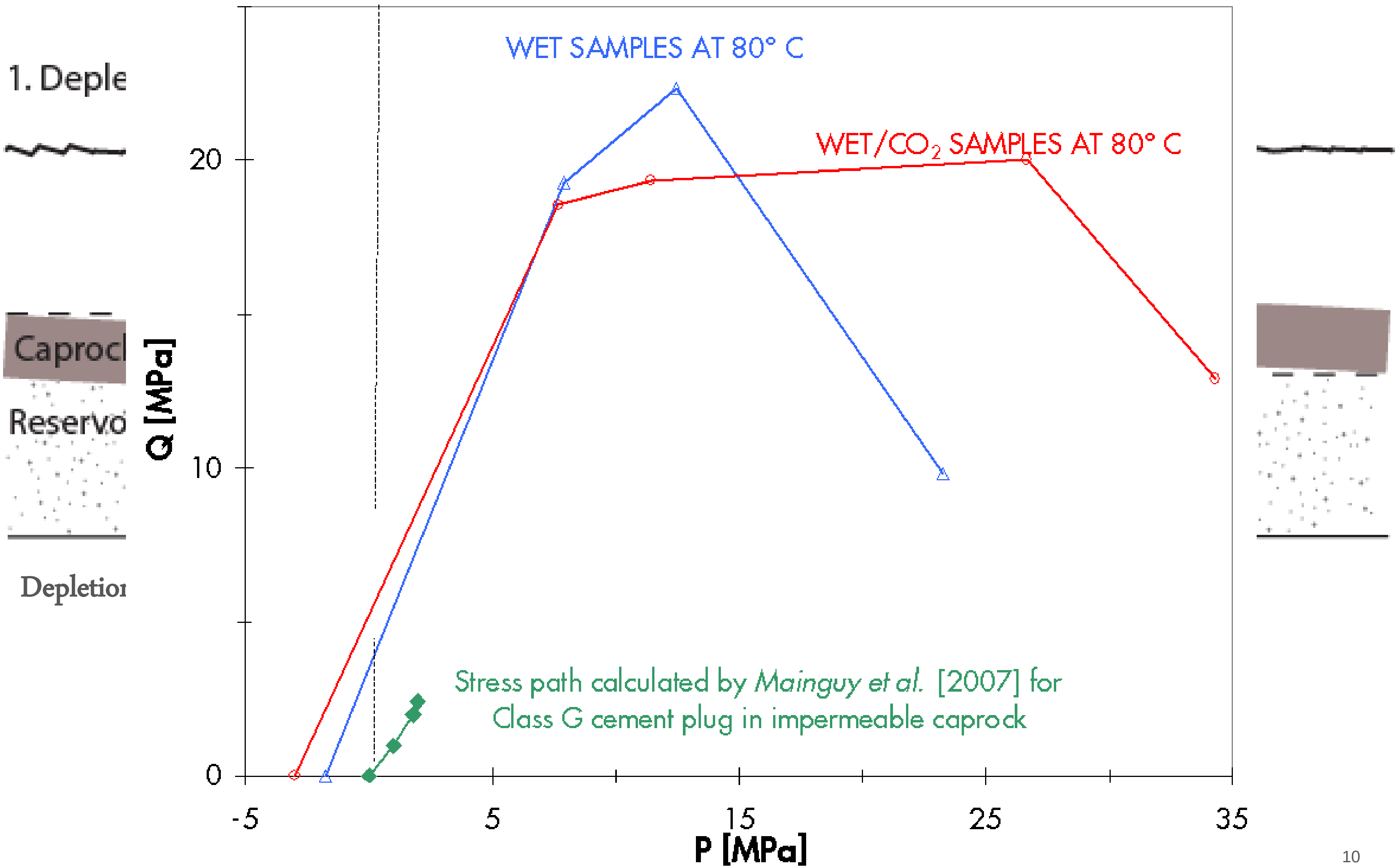
** Philippacopoulos and Berndt, 2001*

+ Stiles, 2006



RESULTS

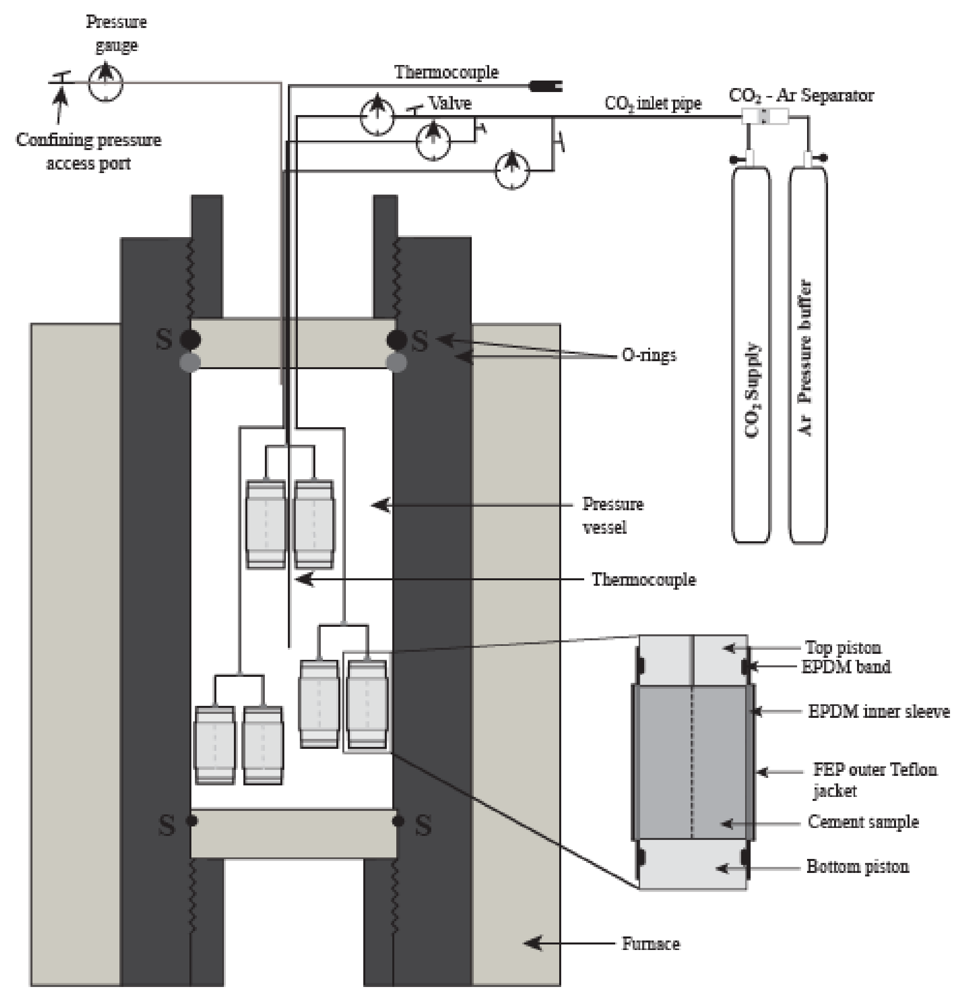
Implications for wellbore integrity



EXPERIMENTAL METHOD

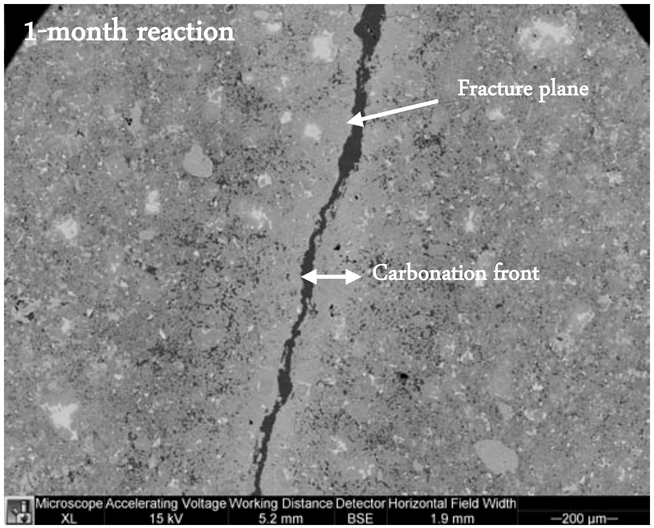
Batch experiments

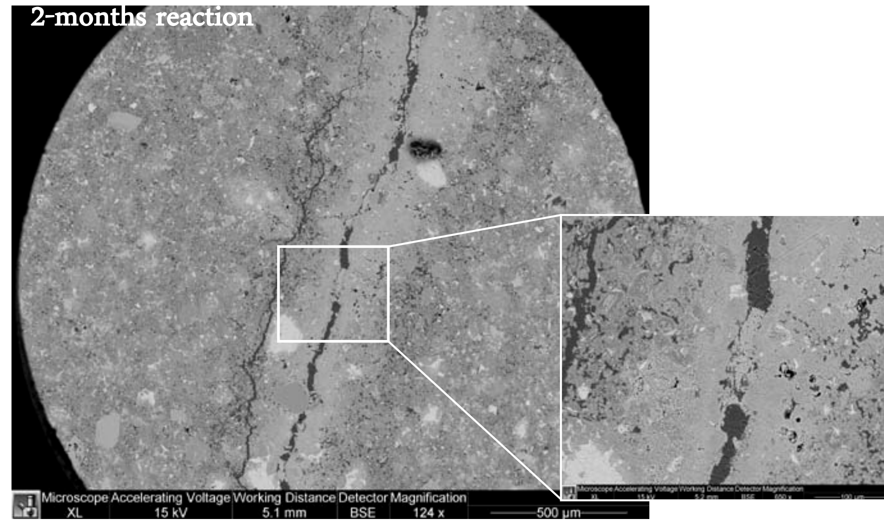
- MATERIALS
  - Cylinders of Type A Portland cement
  - w:c = 0.5 (de Lier Field, Netherlands)
  - Curing time – 6 months
  - Cores = 35 X 75 mm
- EXPERIMENTAL CONDITIONS
  - Temperature = 80°C
  - Confining pressure = 30 MPa
  - P_{CO2} = 10 MPa
  - CO_2- Saturated solution in chemical equilibrium with the samples

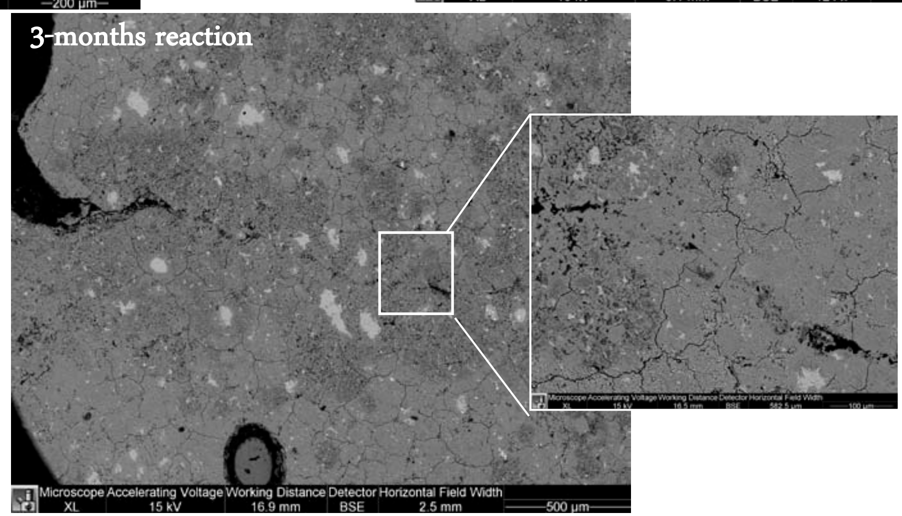


RESULTS

Carbonation of cement

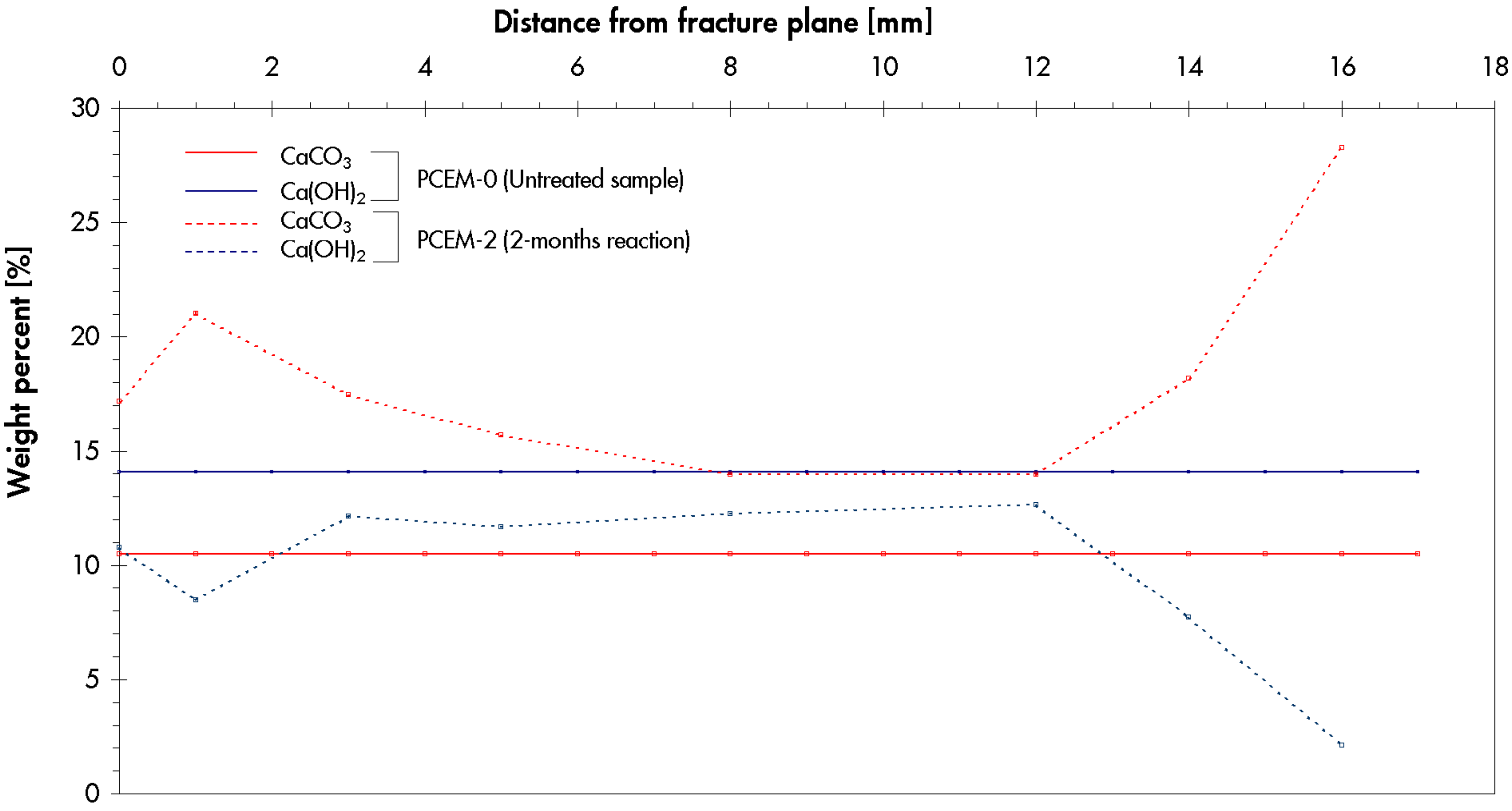






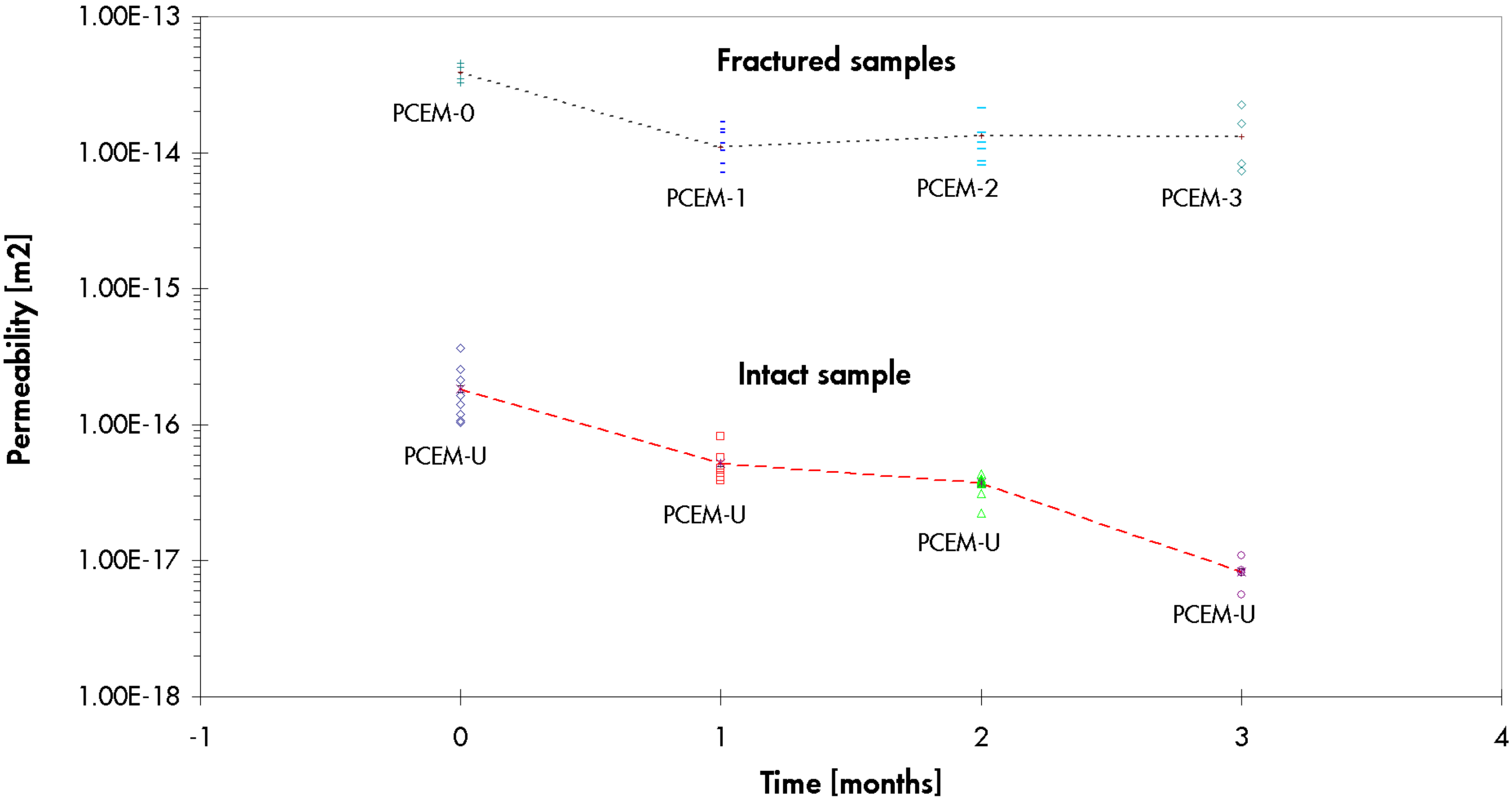
RESULTS

TGA analyses



RESULTS

Permeability measurements



CONCLUSIONS

- Increase in compressive stresses due to fluid re-injection is unlikely to lead to failure of cement plugs localized at impermeable caprock level.
- Fractures present in Class A cement have the potential for self-sealing when exposed to supercritical CO_2.
- Permeability of intact samples decreased over time due to exposure to supercritical CO_2.
- Carbonation is not efficient enough to seal entirely the fractures present in cement samples.

IEA GHG Wellbore Integrity Network

Hague, Netherlands

28 – 29 April 2010

“Grooved Horizontals for Extended Reach Injectors”

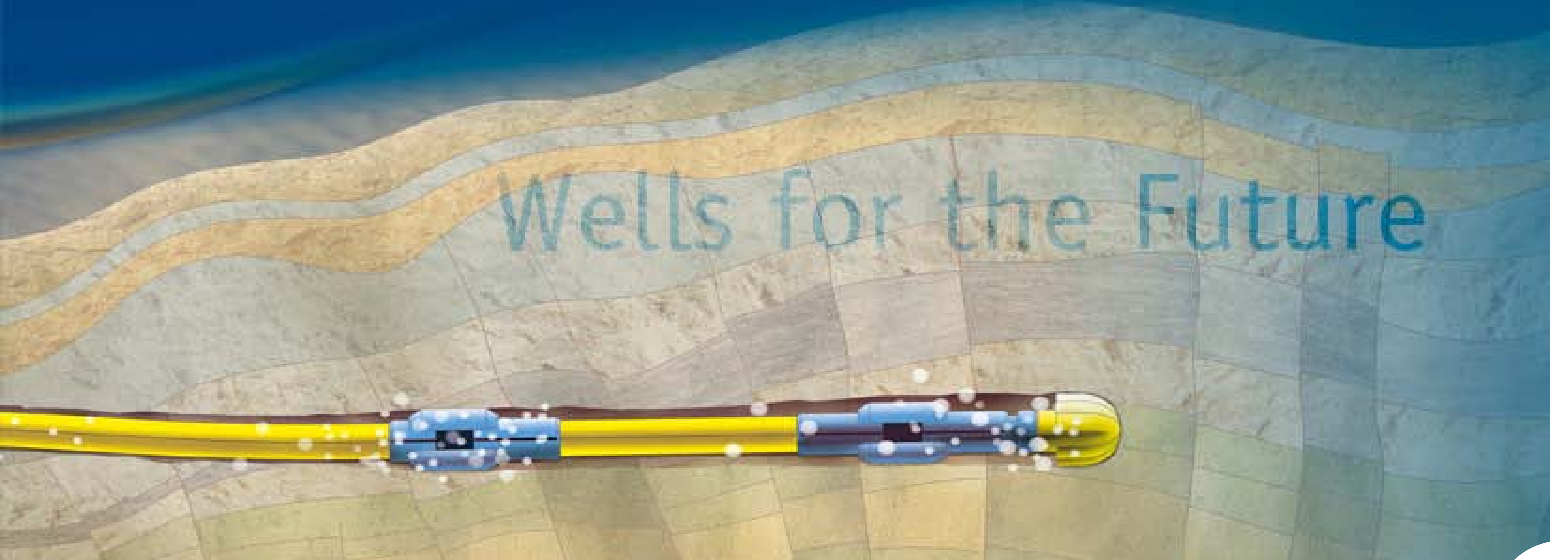
Inge Manfred Carlsen

Research Director, SINTEF Petroleum Research

Co-authors;

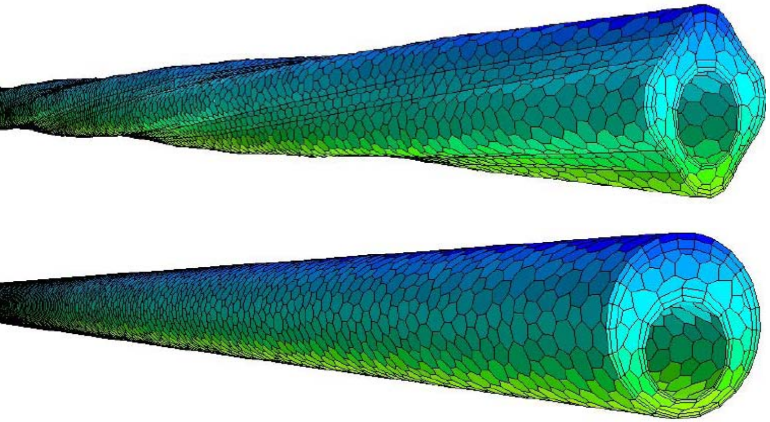
Ali Taghipour

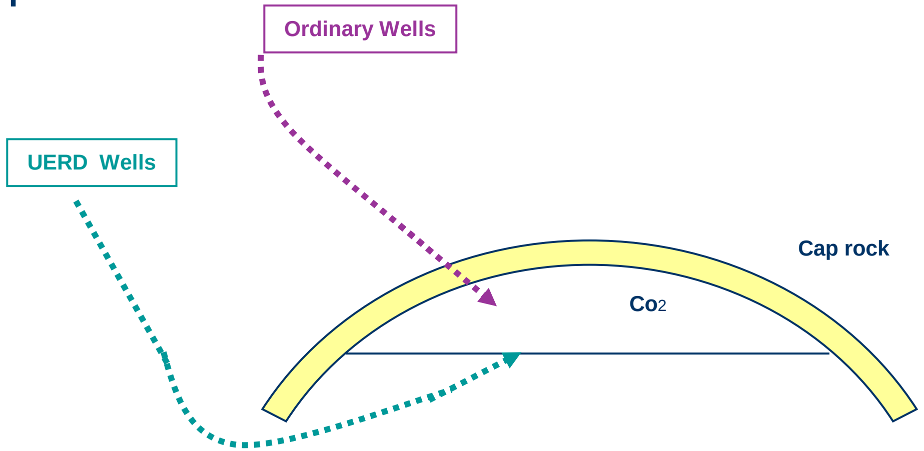
Karen Valencia



Rifle Well – a New Dimension in Well Construction

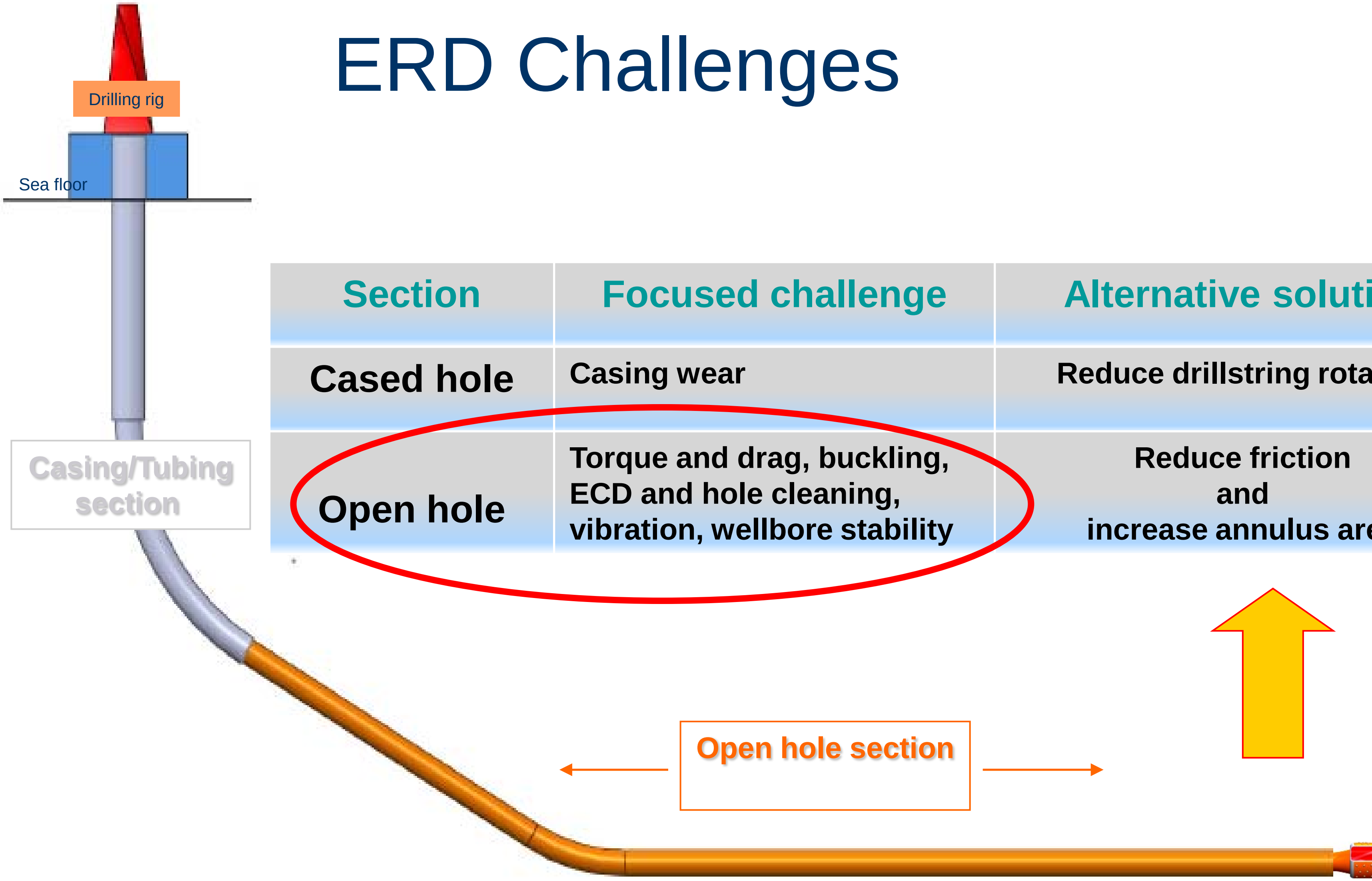
- A grooved wellbore will reduce friction and lower ECD
- Enable to extend the limits of conventional ERD wells
- Ultra-ERD wells for CO_2 injection with improved reservoir exposure and well integrity
  - Penetrate the cap rock from a safer area
  - Drilling from a safer location



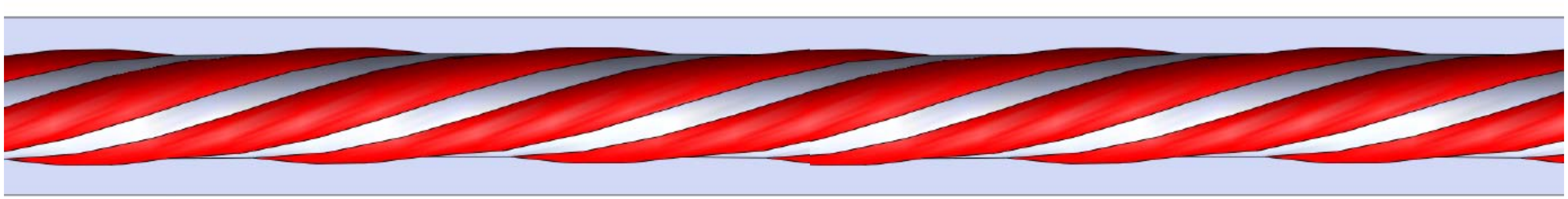


ERD Challenges

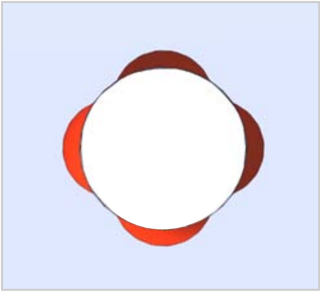
Section	Focused challenge	Alternative solution
Cased hole	**Casing wear**	**Reduce drillstring rotation**
Open hole	**Torque and drag, buckling, ECD and hole cleaning, vibration, wellbore stability**	**Reduce friction and increase annulus area**

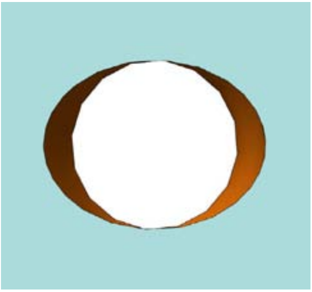


Rifle Shaped Wellbores

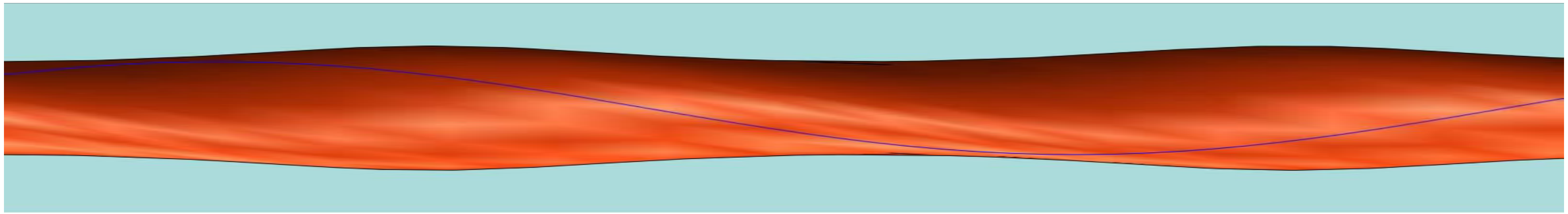


Multi spiral grooves

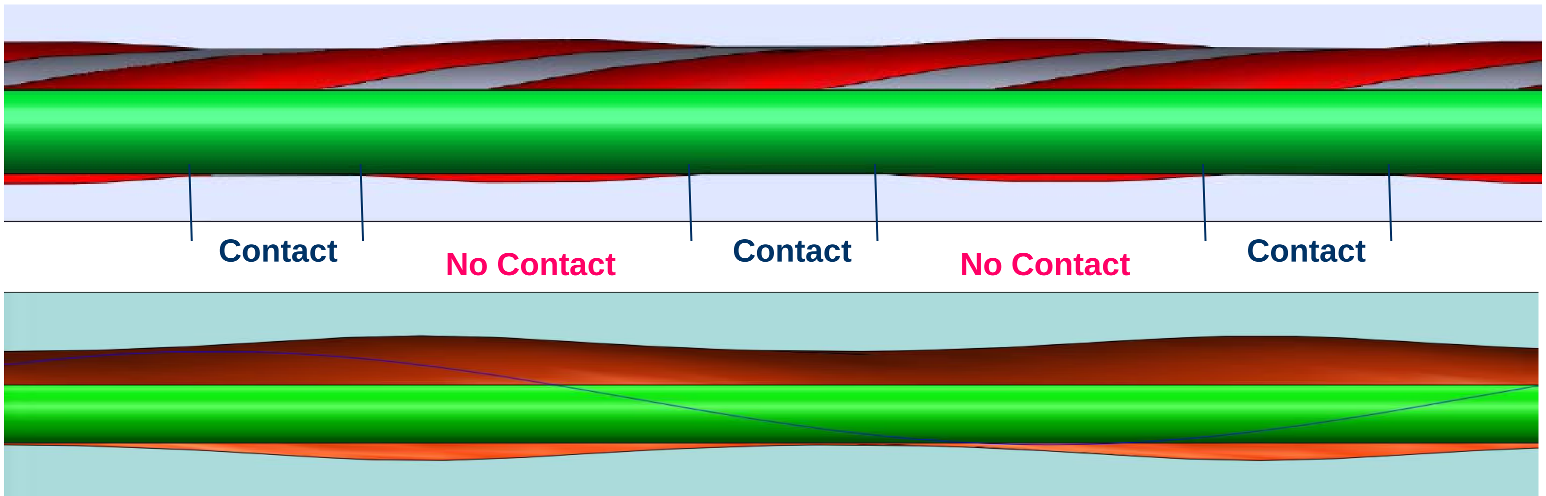




Elliptical



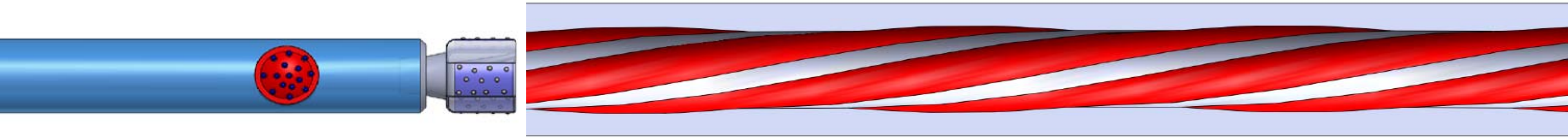
Key Targets



- Increase annulus area while maintaining drillstring buckling limit
- Improve flow pattern
- Reduce drillstring wall contact

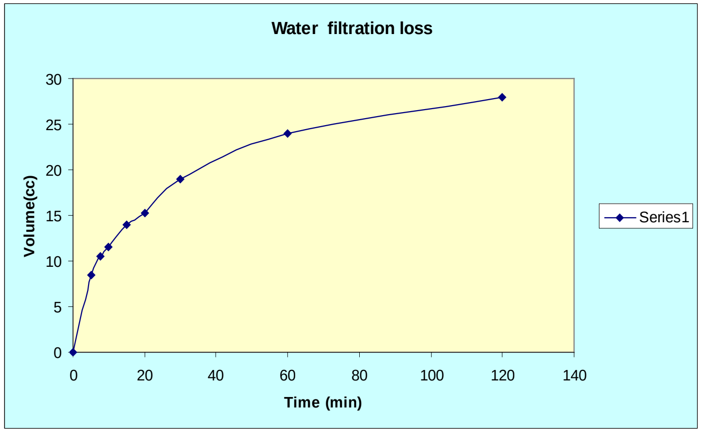
Key Benefits

- Improved hole cleaning and overall friction
  - Reduced ECD
  - Reduced torque and drag
- Improved casing / completion running
  - Reduced differential sticking
- Improved gravel pack operation
- Lower surge/swap allowing faster tripping speed
- Reduced formation damage by improved filter cake quality



Reduced Formation Damage

- Reduced mud cake damage and reduced fluid loss
  - Reduced formation damage in the reservoir section
  - Less skin effect and increased overall recovery in producers
  - Lower injection pressure in injectors
  - Less environmental impact

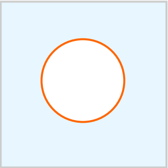


- Early formation fluid loss is high
- Circular: drillstring-to-formation contact is high resulting in constant rebuilding of filtercake
- Rifle well: filtercake at grooves remain intact hence reduced leak-off and damage to formation

Casing/Liner Drilling

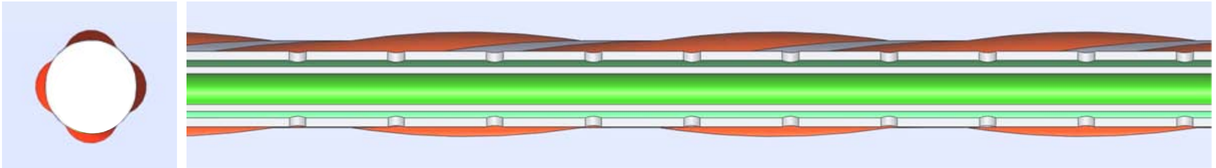
- Rifle geometry will benefit
  - Reduced torque on the casing connections
  - Reduced differential sticking and excess torque
  - Less ECD

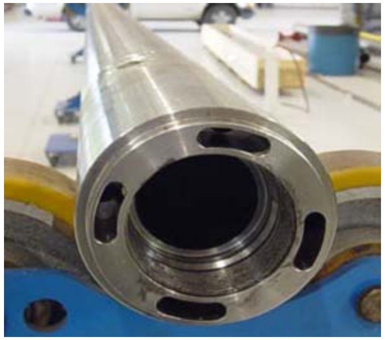
- Rifle tool used as underreamer
  - Less required torque compared to passive reamers
  - Lower required rotation and less fatigue



Improved Gravel Packing

- Improved slurry flow will increase gravel placement during Alpha wave by reduced critical settling velocity
- Improved filter-cake quality with reduced slurry fluid loss avoiding premature screen-out
- Less blocked shunt nozzles
- Reduced sand bridging by increased annulus clearances



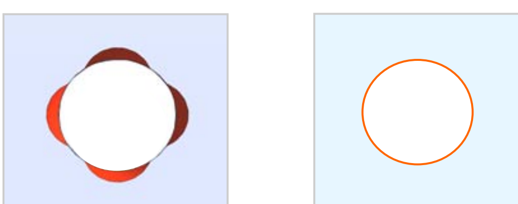


Reservoir Section

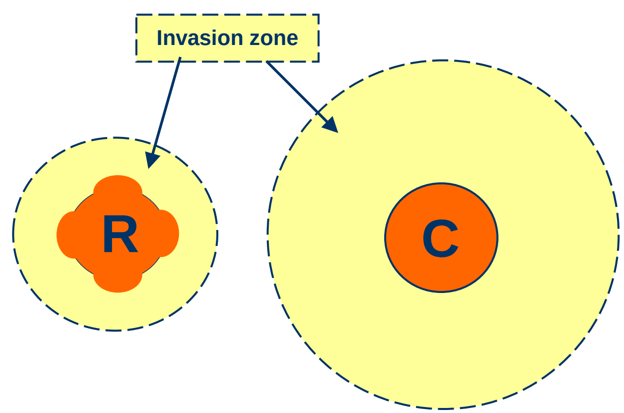
- Increased well injectivity/productivity due to:
  - Enlarged effective wellbore radius
  - Longer horizontal section
  - Reduced mechanical skin

PI is a function of

- Rock properties
- Fluid properties
- Reservoir geometry *(pay thickness, lateral length)*
- Formation damage
- Wellbore radius

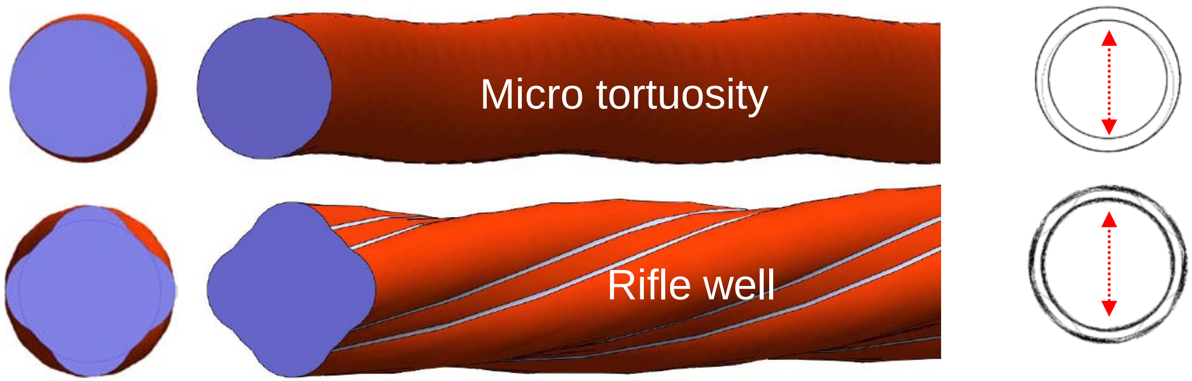


$r_{Rifle} > r_{Circular}$



Frequently Asked Questions

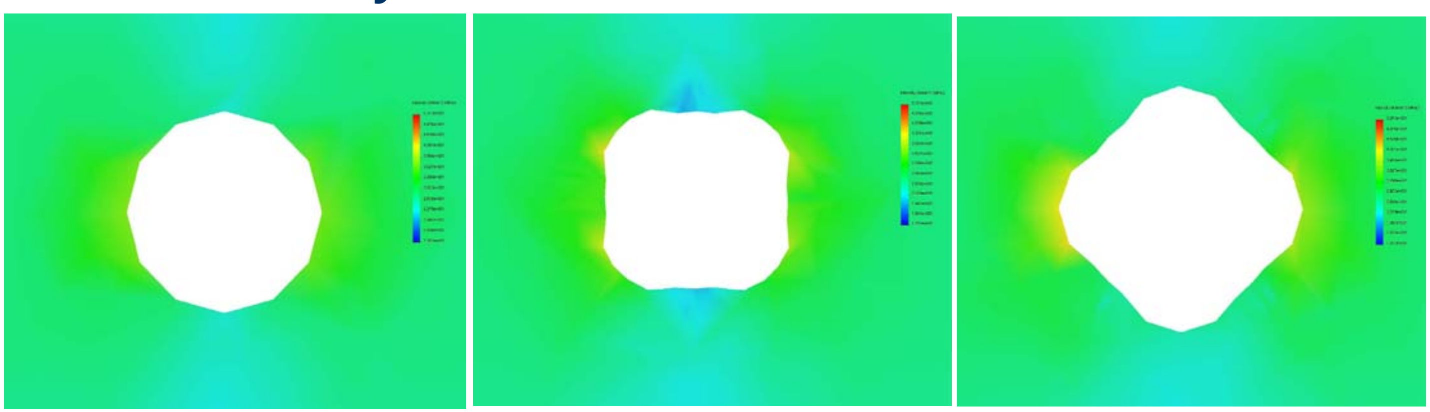
- Tortuosity



Reduced effective diameter

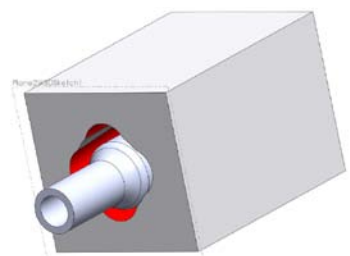
Constant effective diameter/
Increased annulus area

- Wellbore stability



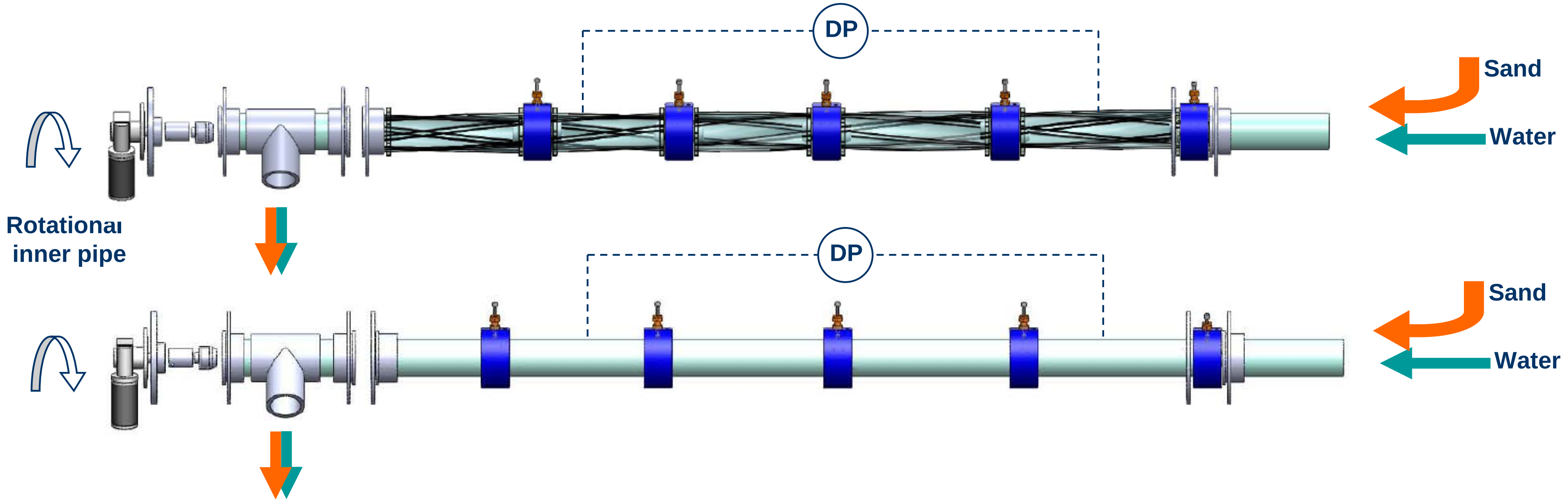
Frequently Asked Questions

- Impact on wellbore logging tools
- Compatibility with steering systems
- Completion packers
- Degradation of grooves
- Falling pipe tool-joints into the grooves



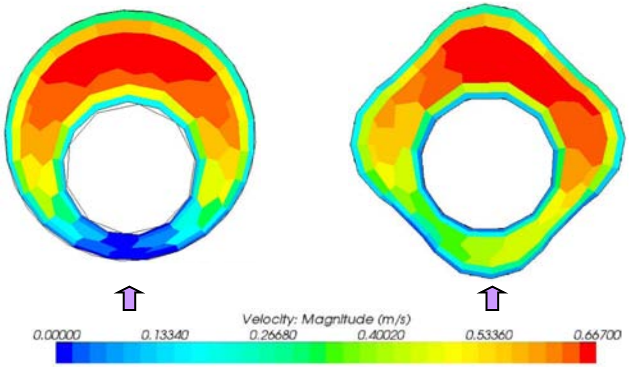
Flow Loop Experiments

- 10 meters transparent plastic tubes with equivalent flow area and rotational inner pipe
- Use of water and sand to study cutting bed build up
- Data acquisition
  - Differential pressure and fluid velocity
  - Continuous video of sand height and critical settling velocity

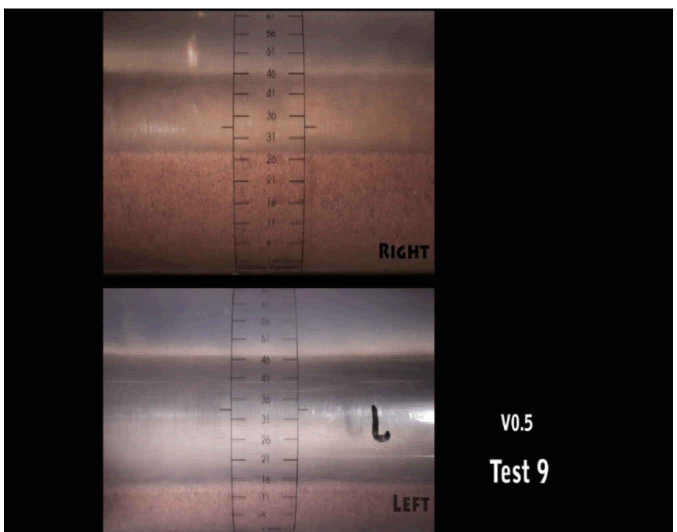


Flow Loop Results

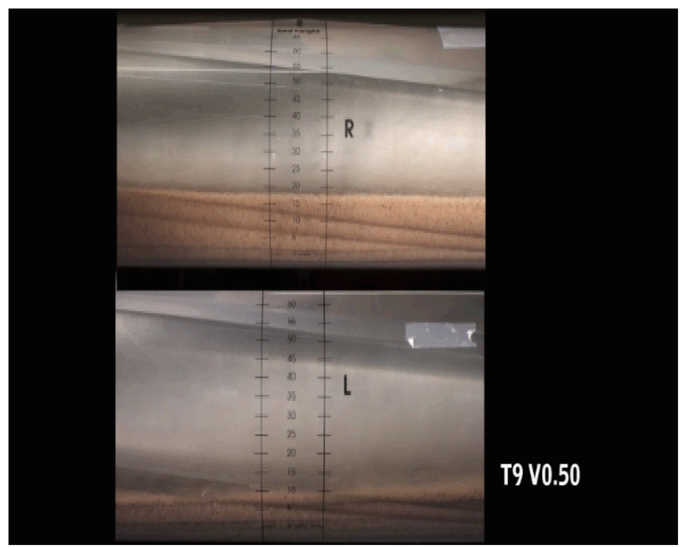
- Lower critical settling velocity and improved cutting transport in the rifle geometry
- Report is available for new partners



- Circular



- Rifle



Rifle Well Status

- International patent filed
- Flow loop experiments performed
  - Validated computer modeling on wellbore cleaning
- R&D project (KMB) granted 2010-2013
  - Fundamental aspects of non circular wellbores
- Applied for innovation funding
  - Field applications
  - Industrial partners

Thank you for your attention!

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Managing integrity of large volumes of wells

By: Paul Hopmans

Well integrity principal technical expert

Shell Exploration and Production

Managing well integrity of large number of wells

- We currently manage the integrity of some 15000 wells using Shell developed system called eWims.
- We manage the wells in accordance to the latest standards that are available with in Shell and industry.
- Validation of as build is an ongoing project that will confirm well operating envlops.
- Management of internal & external corrosion with changing operating conditions is our biggest concern.

What will change with CO2 sequestration?

eWims well integrity management system

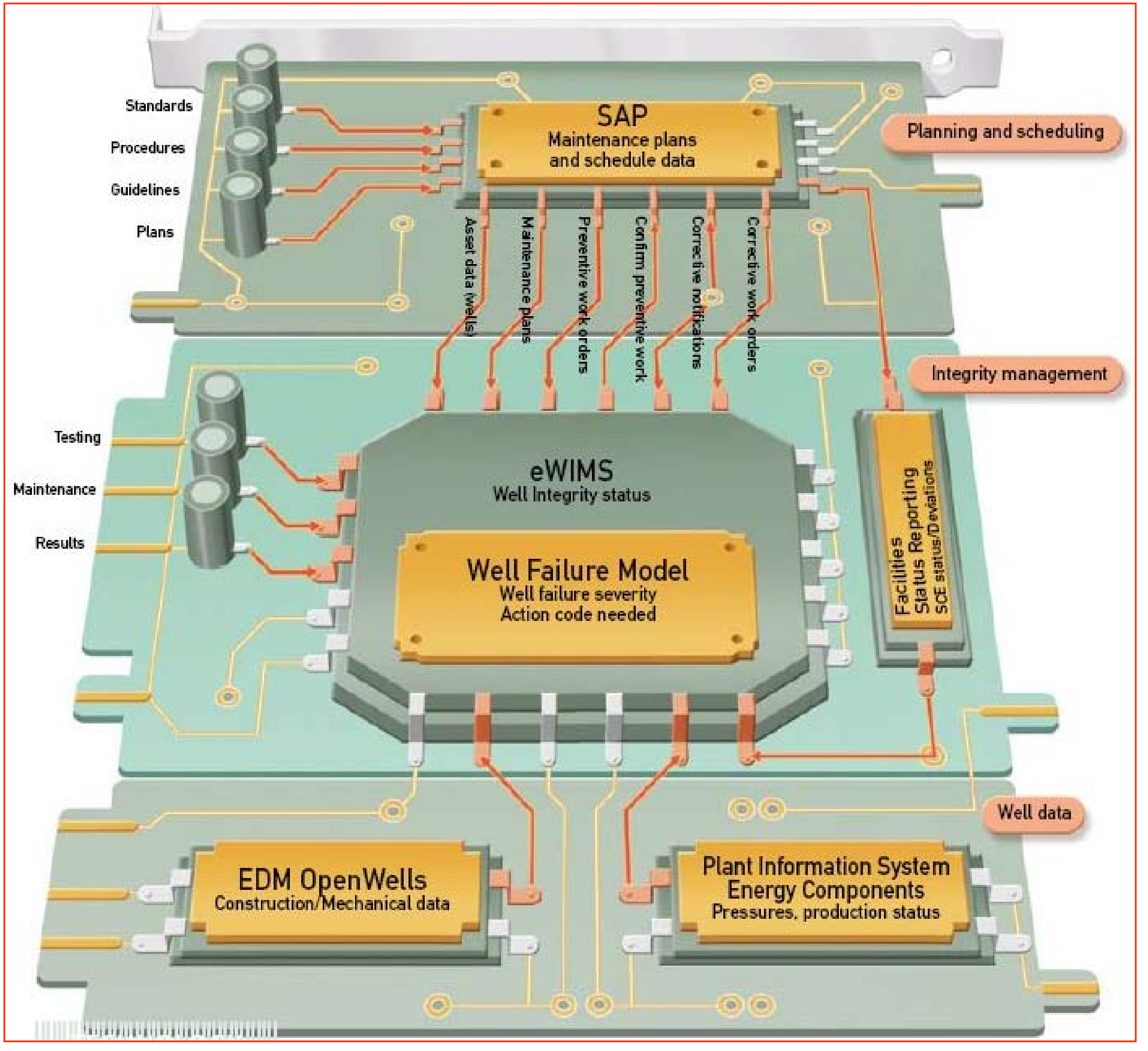
eWims a system that handles 15000 wells

Allows you to manage / overview the status of your wells on.

- Preventive maintenance tasks
- Corrective maintenance tasks
- Annular pressure monitoring
- Blow down and top up
- Conductor inhibitor treatment
- External corrosion monitoring
- Casing load calculation
- Well head growth / subsidence
- Trigger pressures alarms
- Production data upload
- Maasp & mechanical data EDM
- Compliance KPI's
- Notifications to SAP / FSR
- Deviations
- Isolation

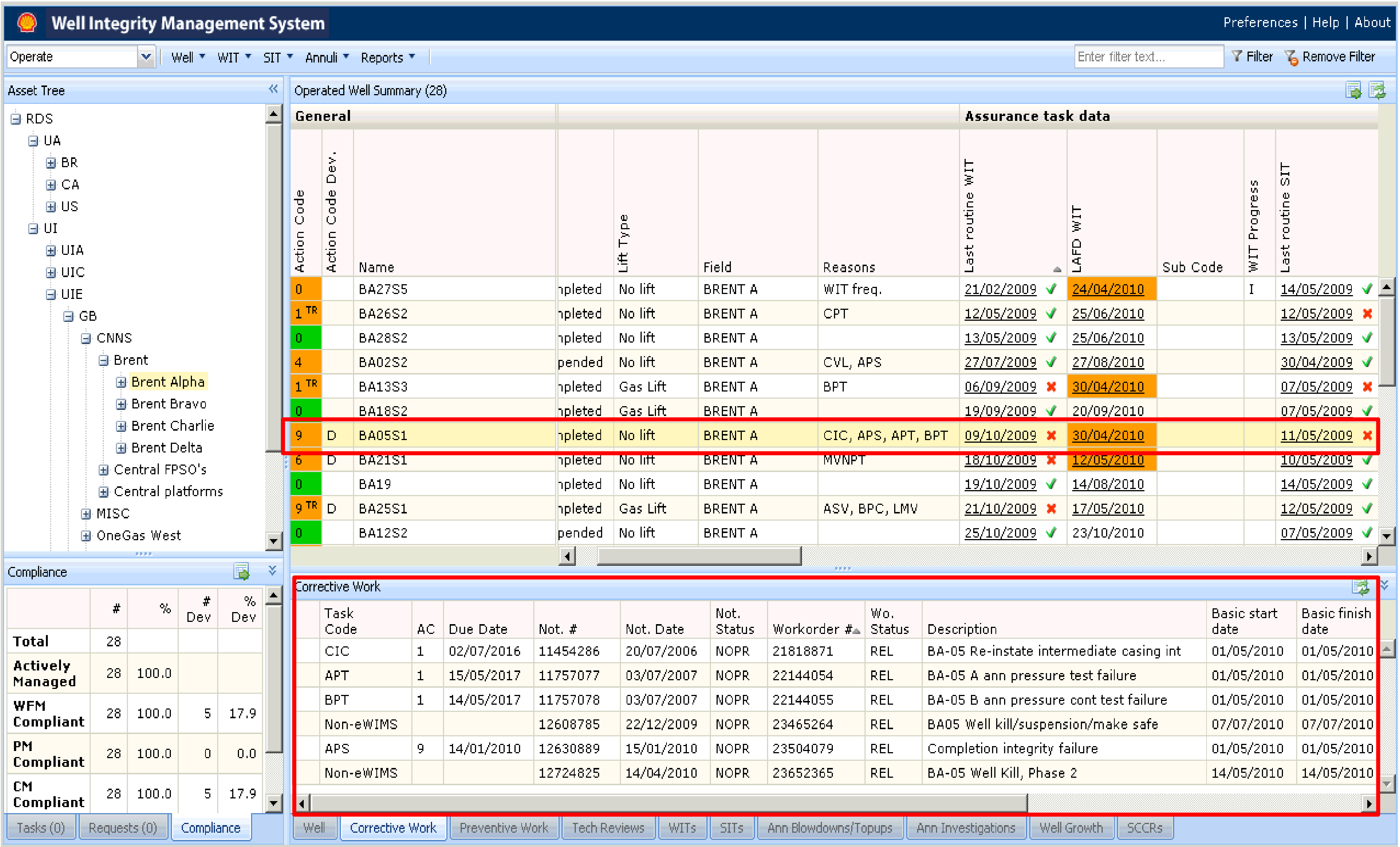
Challenge is to manage:

corrosion of conduit within a conduit .



http://wims.shell.com/#

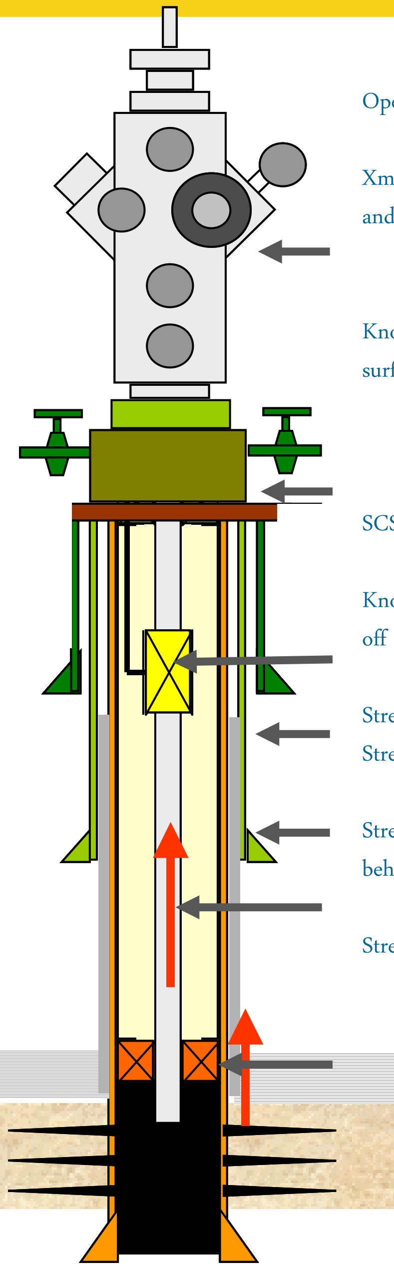
Well Integrity eWims system



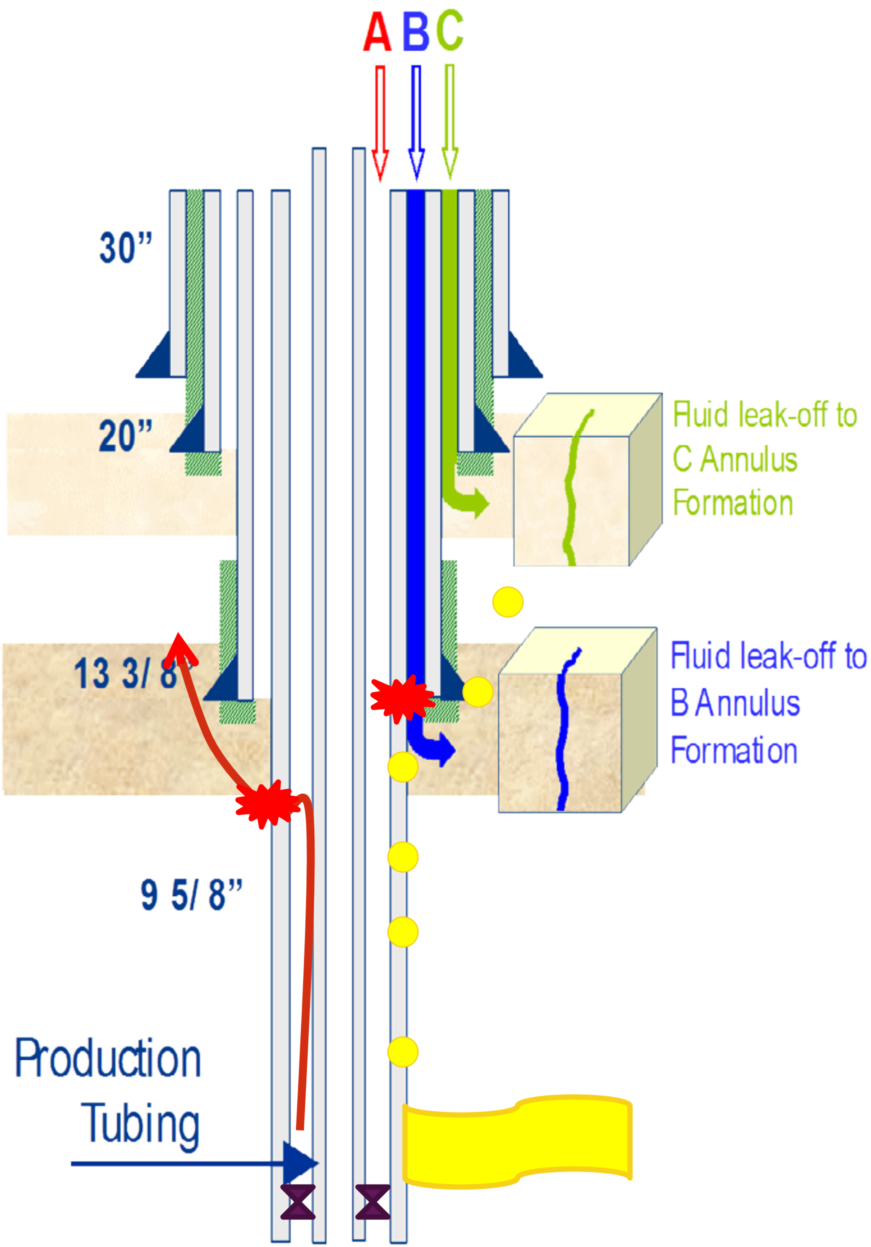
Well Integrity in design requires that:

- Operating Conditions are defined
- Physical behavior is modeled and analyzed
- Functional failure modes are considered
- Safety critical elements are identified
- Performance Standards of Safety Critical Elements are quantified.

What are the changes of CO_2 sequestration in our design envelop to manage well integrity ?



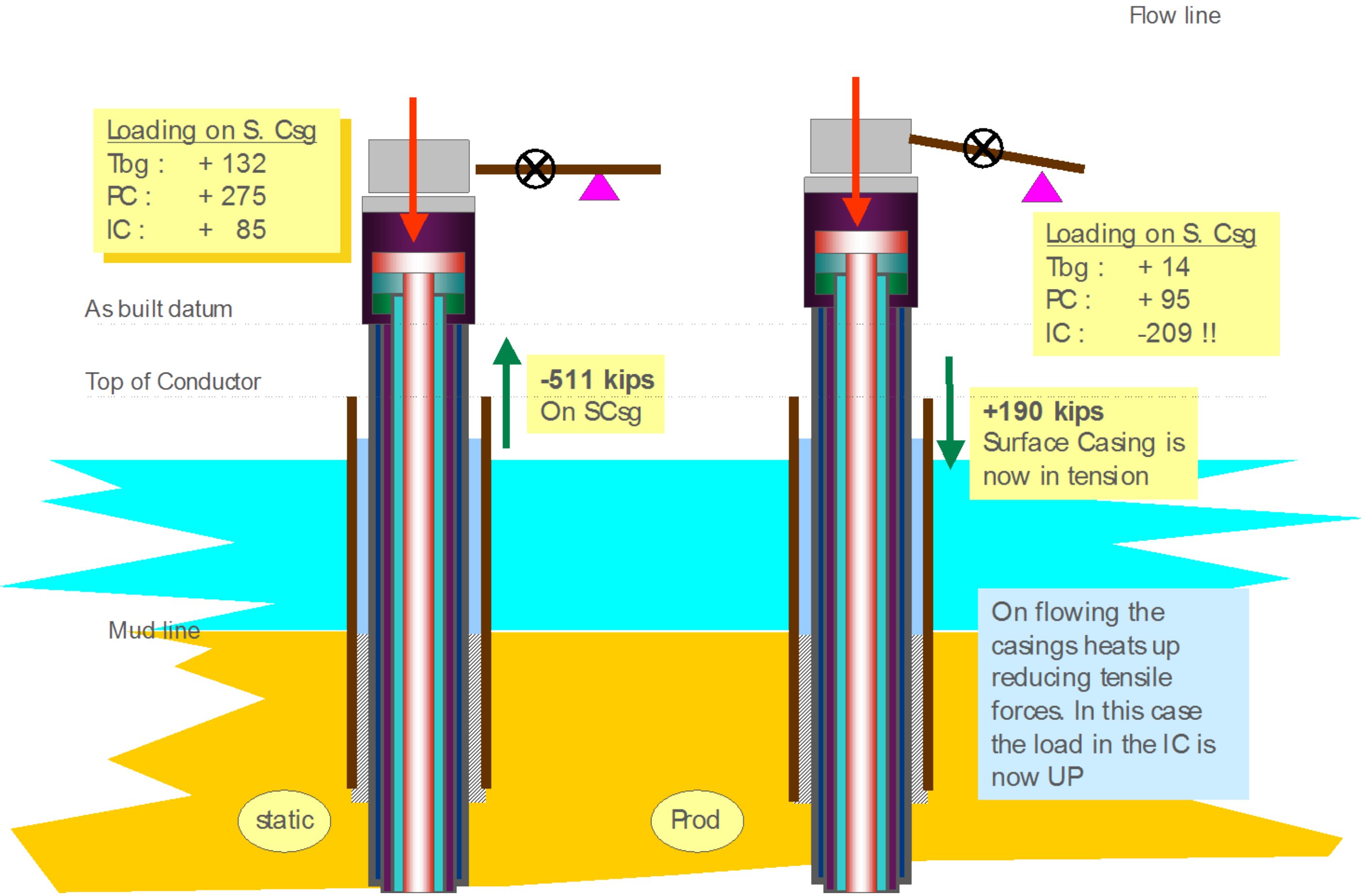
Risk of CO2 with annular communication



- Risk of out flow due to packer failure or tubing failure that may cause casing internal corrosion and breach around shoe .
- Seepage through annulus from reservoir micro annuli that may corrode casing externally and cause out flow .
- Well collapse due to casing corrosion

Risk associated with Casing Failure – jump or slump

- Reducing the wall loss though external corrosion can lead to a loss of containment but also to structural failure
- Loads are worst in Injection wells and when the well cools



CO2 sequestration challenges to Well Integrity

- Risk of failure due to loss of external casing barriers (CO2 leak and poor cement bonds)
- Field reviews for CO2 sequestration have demonstrated that we have not constructed our wells or abandoned them suitable for CO2 sequestration.
- Risk assessment to changes to well operating envelop for CO 2 sequestration is being debated ,no clear standard (DNV is working a proposal in a JIP)
- Iso standard proposal via OGP in preparation supported by the major Operators to address wells lifecycle integrity in operate phase.

Well integrity management standards & systems are not inclusive of CO2 sequestration risks.

Check list when you change a well to CO_2 injector is this complete?

- Casing and tubing and tubing accessories and wellhead (such as packer, flow control nipples, SCSSV, etc) all meet CO_2 materials spec?
- Casing and tubing system meet injection pressure requirements Well cat has been modeled?
- Confidence in cap rock and cement seal for the reservoir pressures expected during injection?
- testing can be done to confirm this in the near well bore region (tracer injection tests, temp logs, etc.)
- Cement integrity confirmed & type of cement used on production casing.
- CO_2 ratios are important to know for both cement integrity and material corrosion.
- Possible corrosion due to presence of water in the CO_2, due to failure of surface equipment or back flow from reservoir.

Check list when you change a well to CO_2 injector is this complete?

- Casing design i.e. material compatibility, from field perspective like we has seen with upper and lower intervals separately explored,
- Wellheads, & X mass tree , seals and feed through, check compatibility for CO_2, may have to flush valves with specific grease. check with well head manufacturer.
- Pressure gauges , transducers and other threaded & fitted components to well need to be checked if for CO_2 compatibility
- Well head control panel needs to be checked for CO_2 compatibility as flow back from control line can enter can hit panel.
- Annular monitoring in event of communication problems, are there current existing sustained annulus pressures and have samples been taken to finger print the source of the medium that causes sustained annulus pressure and is there a likely hood that this can escalate over time due to micro annuli connectivity with CO_2 injection.
- Change in Emergency Response Plans and operating procedures for wells.

Conclusion

- Co2 sequestration well integrity management requires an other set of components to be measured, monitored and maintained.
- Abandoned wells and other producers may have to be included.
- Adjacent fields or upper or lower reservoir that are explored on it's own may over time comingle.
- Monitoring of these wells in these fields may become a requirement.
- Standards need to be inclusive of CO2 well operating envelops and risk criteria in the operate phase

Schlumberger
Carbon Services

Quantification of wellbore leakage risk using non-destructive borehole logging techniques

6th Wellbore Integrity Network Meeting

Andrew Duguid

April 29, 2010

WORK PERFORMED UNDER AGREEMENT
DE-FE-0001040

U. S. Department of Energy
National Energy Technology Laboratory

Outline

Schlumberger
Carbon Services

Objectives

Research Partners

Background

Tasks

Summary

Co-Investigators

Matteo Loizzo

T.S. Ramakrishnan

Vicki Stamp

Mike Celia

Bill Carey

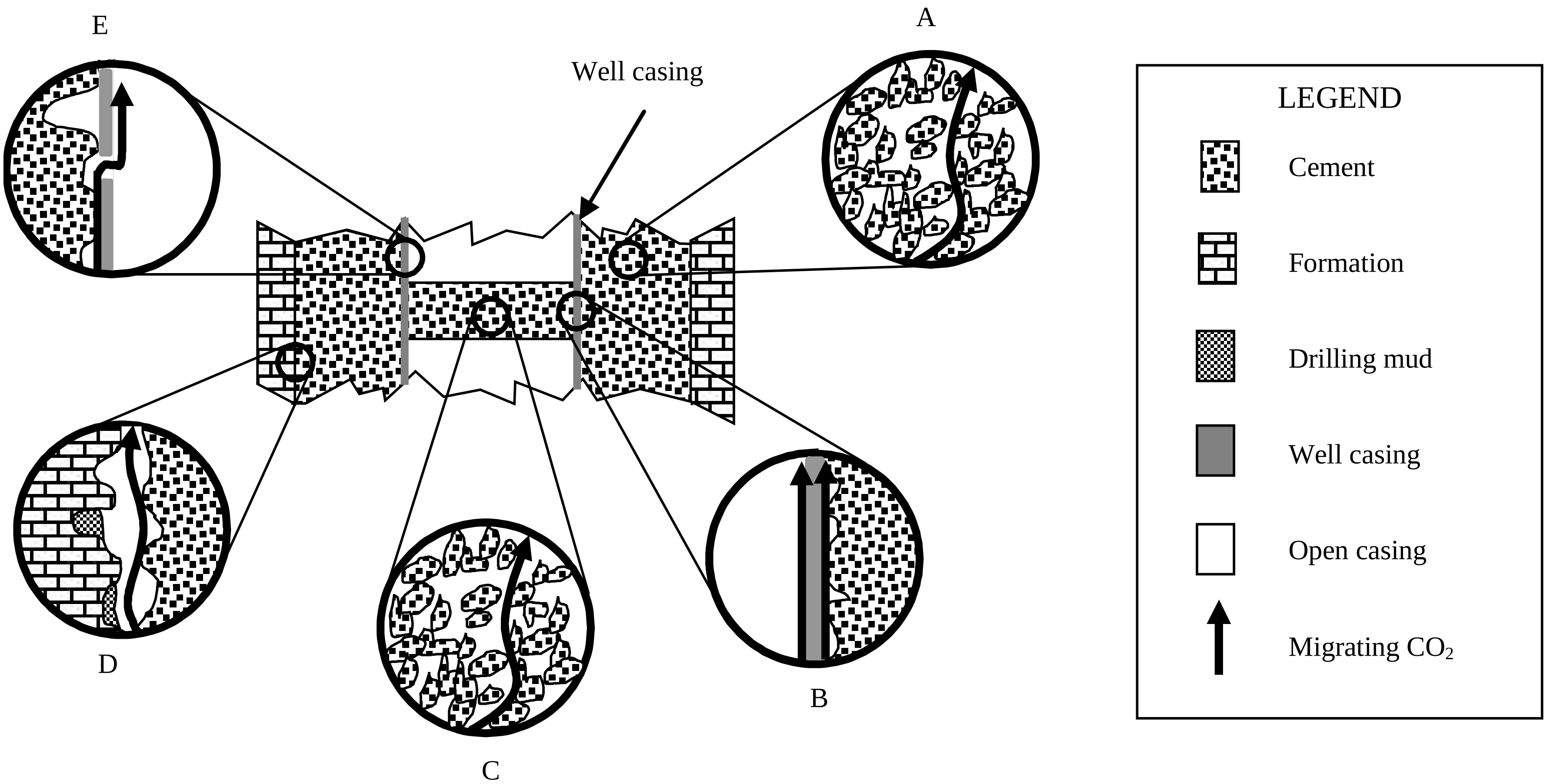
Industry Partner

Objectives

- Investigate methods to establish the average flow parameters (porosity and permeability or mobility) from individual measurements of the material properties and defects in a well.
- Investigate a correlation between field flow-property data and cement logs that may be used to establish the flow-properties of well materials and well features using cement mapping tools.
- Establish a method that uses the flow-property model (Objective 2) to analyze the statistical uncertainties associated with individual well leakage that can provide basis for uncertainty in risk calculations.

Potential avenues for leakage

Schlumberger Carbon Services



Background: Typical well cement composition

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Unhydrated

Phase	Percent
$3CaO \bullet SiO_2$	50
$2CaO \bullet SiO_2$	30
$3CaO \bullet Al_2O_3$	5
$4CaO \bullet Al_2O_3 \bullet Fe_3O_3$	12

Hydrated

Phase	Abbreviation	Percent
$Ca_3Si_2O_7 \bullet 4H_2O$	C-S-H	50-70
$Ca(OH)_2$	CH	20-25
$3(3CaO \bullet Al_2O_3 \bullet CaSO_4 \bullet 12H_2O)$	AFm	10-15
$4CaO \bullet (Al,Fe_2O_3) \bullet 13H_2O$	AFt	

Data from Nelson, 1990

Background: Cement degradation reactions

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Ca(OH)$_2$ dissociation

$$Ca(OH)_2 \leftrightarrow Ca^{2+} + 2OH^-$$

May open up new porosity

CO_2 dissociation

$$CO_2 + H_2O \leftrightarrow H_2CO_3^* \leftrightarrow H^+ + HCO_3^- \leftrightarrow 2H^+ + CO_3^{2-}$$

Cement dissolution

$$Ca(OH)_2(s) + 2H^+ + CO_3^{2-} \rightarrow CaCO_3(s) + 2H_2O$$

$$Ca_3Si_2O_7H{\bullet}4H_2O(s) + 2H^+ + CO_3^{2-} \rightarrow CaCO_3(s) + SiO_xOH_x(s)$$

$$Ca(OH)_2(s) + H^+ + HCO_3^- \rightarrow CaCO_3(s) + 2H_2O$$

$$Ca_3Si_2O_7H{\bullet}4H_2O(s) + H^+ + HCO_3^- \rightarrow CaCO_3(s) + SiO_xOH_x(s)$$

Precipitation of $CaCO_3$ blocks connected pores and reduces permeability

Calcium carbonate dissolution

$$CO_2 + H_2O + CaCO_3(s) \leftrightarrow Ca^{2+} + 2HCO_3^-$$

$$2H^+ + CaCO_3(s) \leftrightarrow CO_2 + Ca^{2+} + H_2O$$

Opens pores blocked by $CaCO_3$ precipitation and additional porosity created by the dissolution of cement reaction products

Project Tasks

Task 1 Project Management and Reporting

Task 2 Data Collection and Analysis

Task 3 Model Development

Timeline

Task 2 Data Collection and Analysis

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Subtask 2.1 Final Well Selection

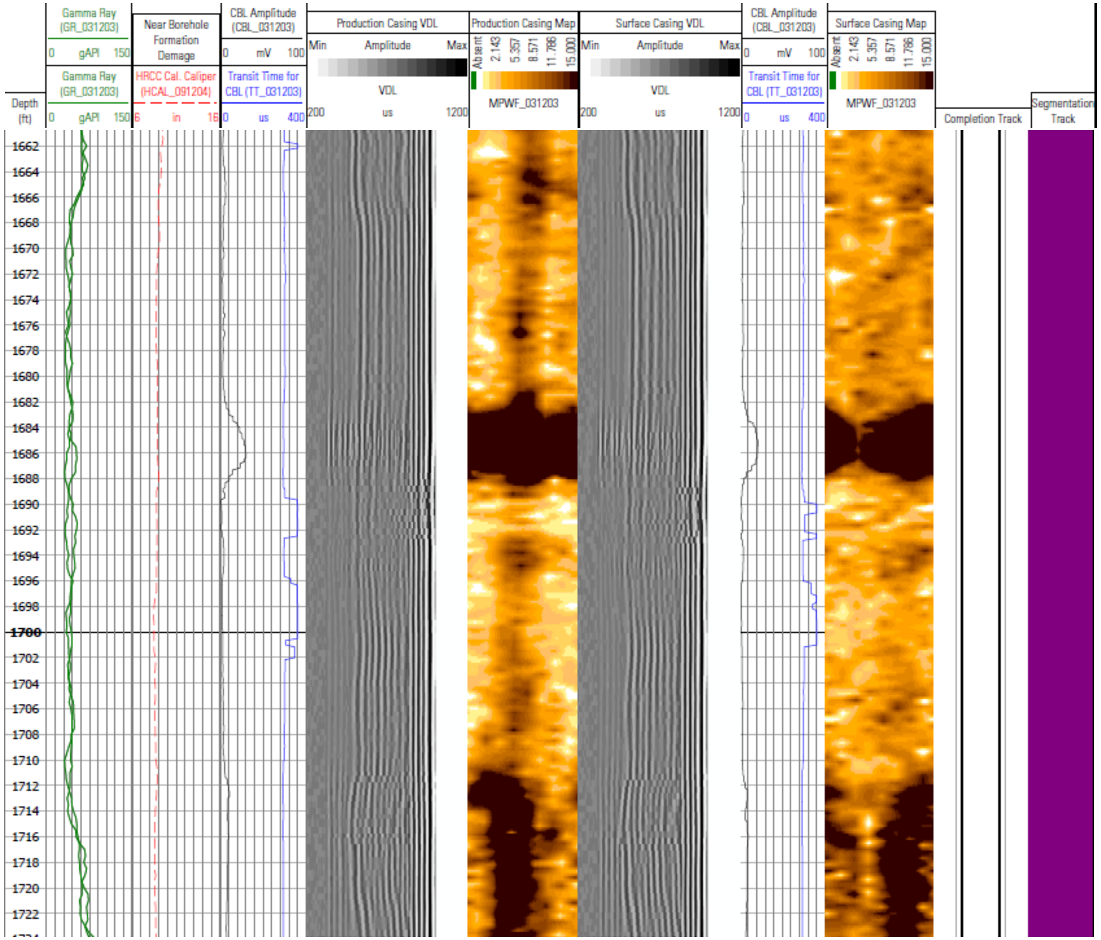
Subtask 2.2 Data Collection and Characterization Effort

- **Industry Wells — Data Collection Completed**
- **DOE Wells — As we speak!**

Subtask 2.3 Data Analysis

Existing data

- **All three industry wells had existing open- and cased-hole Schlumberger logs**



2.2 Data Collection

Logging Tools

- Isolation Scanner
- Sonic Scanner
- Slim Cement Mapping Tool (SCMT)
- Cement Bond Tool (CBT)
- Reservoir Saturation Tool (RST)-(Only if gas is detected in the testing zones)

Testing and Sampling Tools

- Cased-Hole Dynamics Tester (CHDT)
- Modular formation Dynamics Tester (MDT)
- Mechanical Sidewall Coring Tool (MSCT)

Logging and Sampling Plan

	Industry Wells			DOE Wells	
	Well 1	Well 2	Well 3	Well 1	Well 2
Completion Year	2002	2004	2004	1996	1985
Run 1	JB – Gauge – CCL	JB – Gauge – CCL	JB – Gauge – CCL	JB – Gauge – CCL	JB – Gauge – CCL
Run 2	SCMT-GR-CCL	SCMT-GR-CCL	SCMT-GR-CCL	CBT-GR-CCL	CBT-GR-CCL
Run 3	IBC-GR-CCL	IBC-GR-CCL	IBC-GR-CCL	IBC-GR-CCL	IBC-GR-CCL
Run 4	Sonic Scanner	CHDT	~~CHDT~~		
Run 5	~~Temp/Pressure/RST*~~			Temp/Pressure/RST*	CHDT
Run 6	CHDT			CHDT	
Run 7	Perf			Perf	
Run 8	MDT VIT			MDT VIT	
Run 9	MSCT 10 CH Cores			MSCT 10 CH Cores	
Run 10	IBC-GR-CCL			IBC-GR-CCL	

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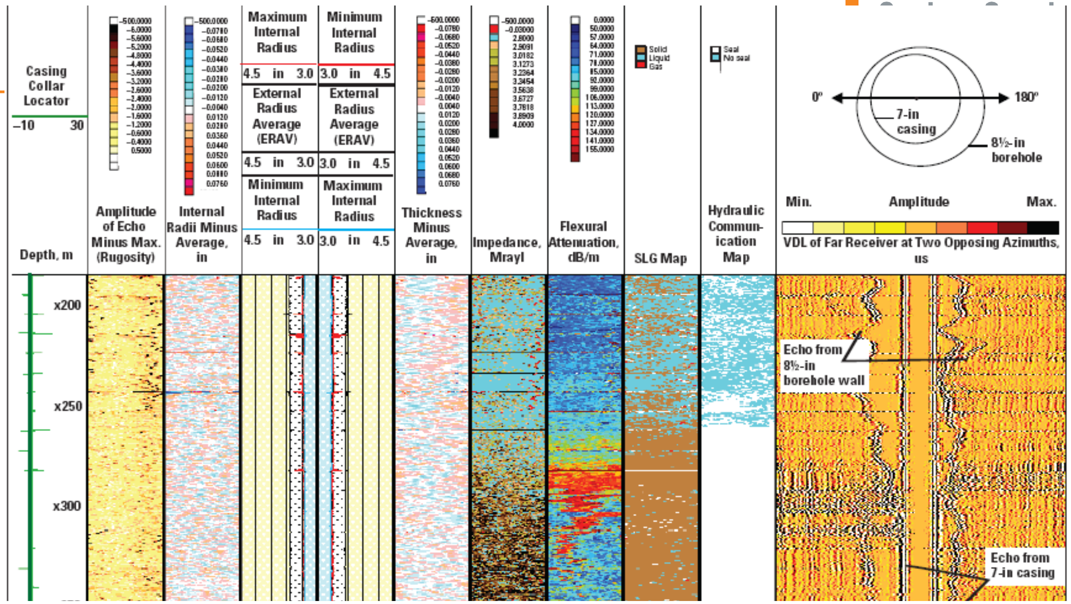
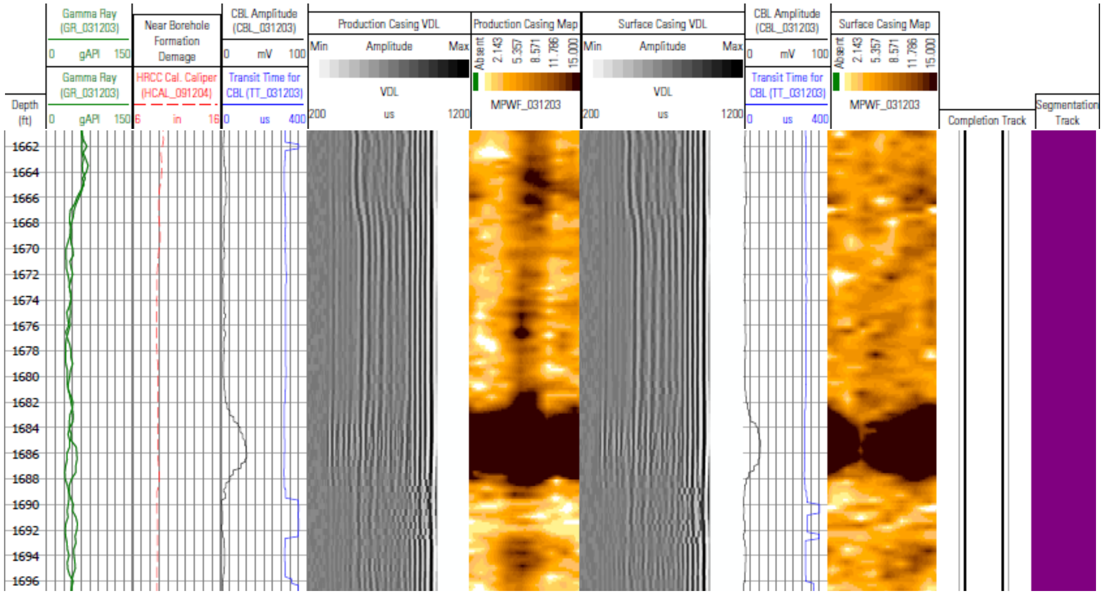
Cement logging

Isolation Scanner



SCMT/CBT



Well Sampling

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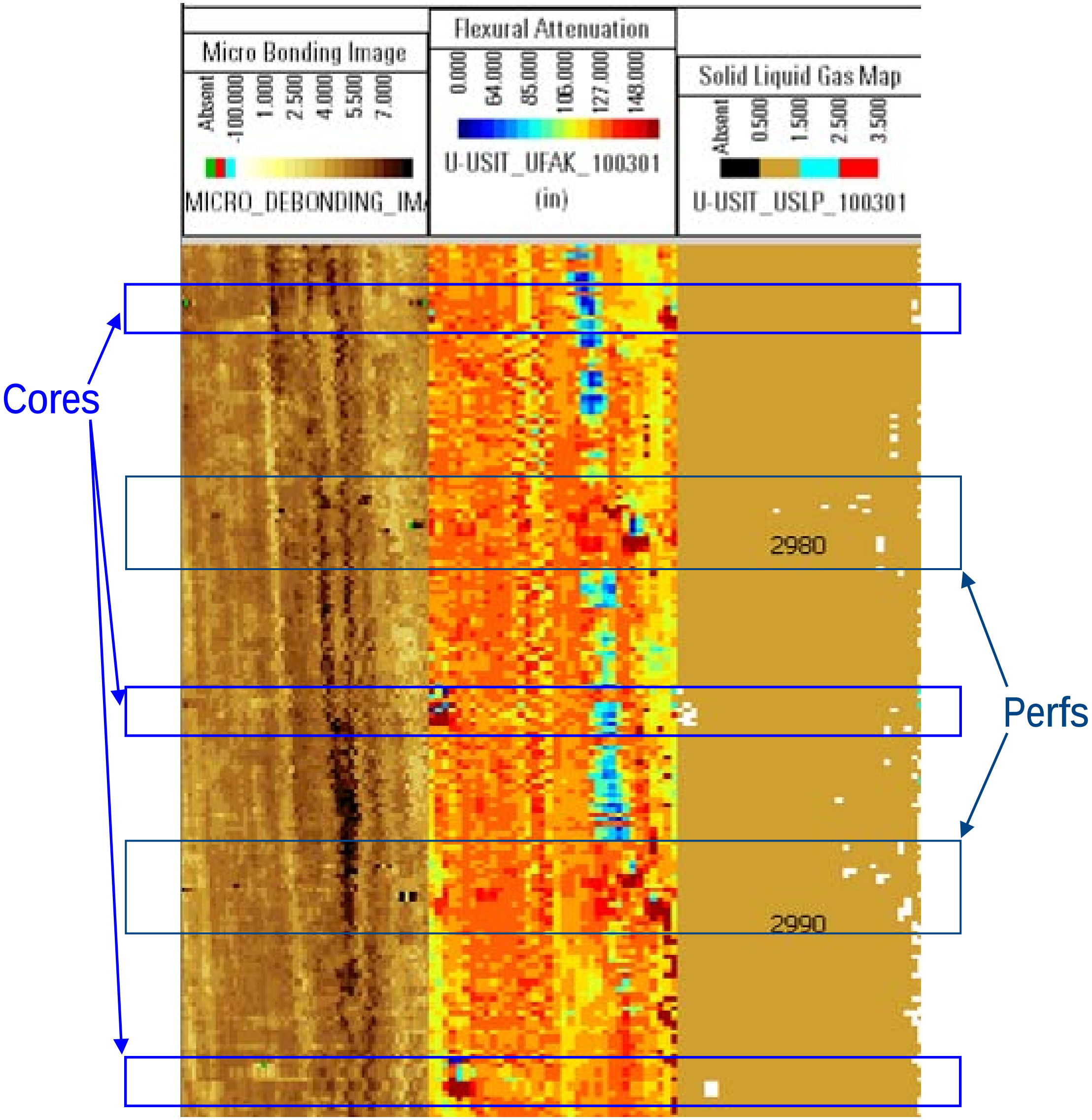

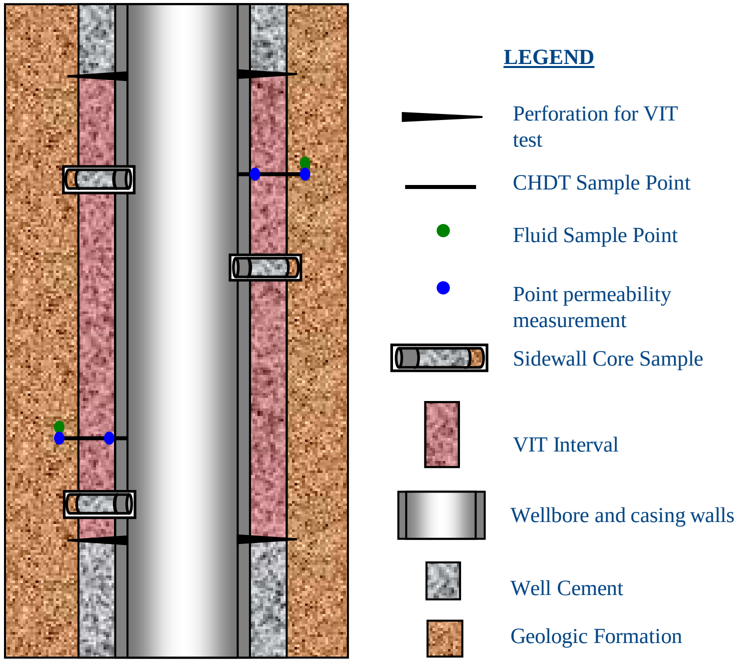

Well Sampling-MDT

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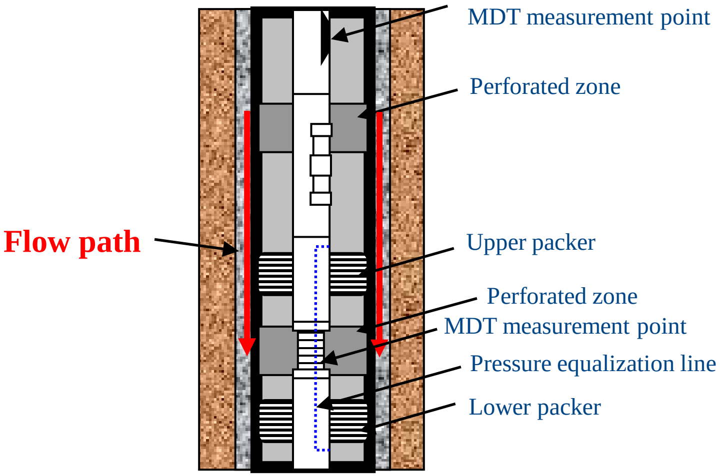
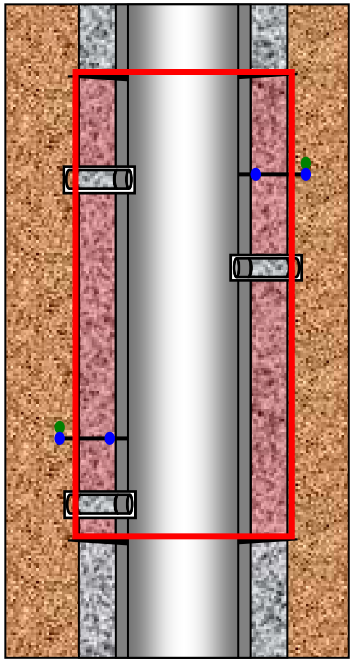
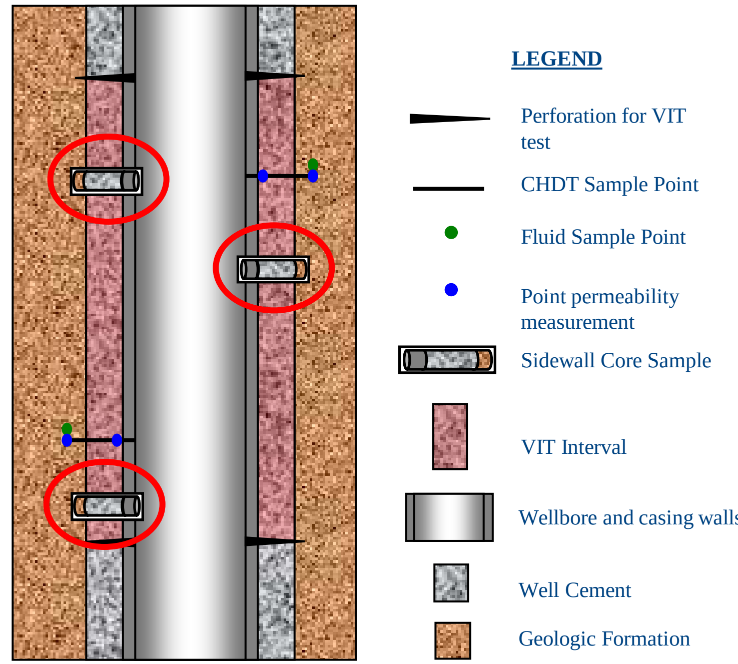
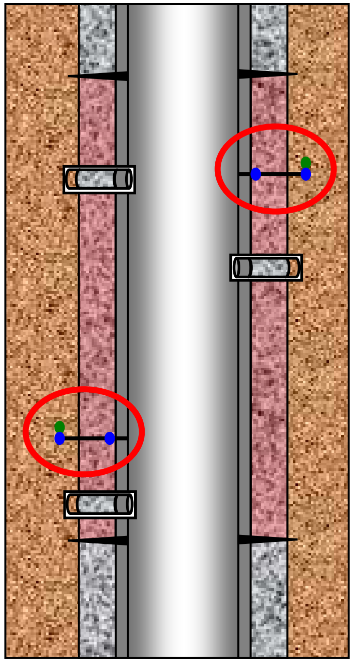


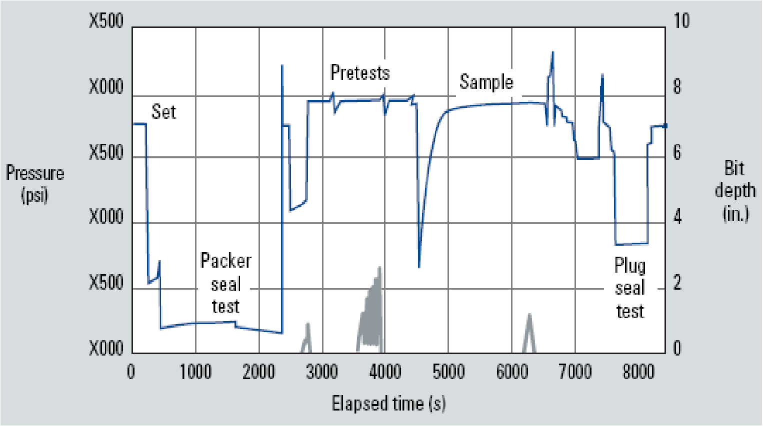


Well Sampling-MSCT



Well Sampling-CHDT





2.3 Expected Analysis

- QA/QC Isolation scanner logs, identify changes between 1st and 2nd run, create parameter maps (Z, flexural attenuation, radii, etc)
- QA/QC SCMT/CBT logs, identify changes between original logs and new logs
- VIT Analysis: Develop a model to estimate the average flow properties using the continuity equation for single phase compressible flow in a porous medium. The model will be used to fit the data and back out the average permeability.
- The CHDT mobility tests in the cement sheath will be analyzed by numerically fitting the data backing out the permeability using a novel process that is currently undergoing the US patent process.
- The CHDT fluid samples will be analyzed for at reservoir pressure and temperature. The fluid will be analysis consist of an extended water analysis and a live water pH measurement. The extended water analysis will provide the concentrations of the ionic constituents present in the fluid samples
- Sidewall Core Analysis: Ultrasonic velocity, Porosity, Permeability, Young's Modulus, Poisson's Ratio, XRD, SEM, X-Ray Map, Optical Microscopy

Task 3 Model Development

Subtask 3.1 – Synthesis of relationships between flow parameter measurements

- Depend on the magnitudes of the values of the flow parameters and on the distribution of cement and defects within the well.
- Possible that the measurements will correlate without the need for any sort of relationship, although this is unlikely. It is more likely that an averaging or scaling technique will be needed to relate the point estimates to the estimate of the average flow properties.

Subtask 3.2 – Correlation of flow parameter data with cement maps

Subtask 3.3 – Analysis of measurement and model uncertainty and implications for incorporation into performance and risk models

- The data from the flow property maps will be used to create probability density functions (PDFs) of well permeability.
- The permeability PDFs will be sampled in a Monte Carlo fashion to create a population of simple well leakage models that can be used to determine the probability of leakage by taking the ratio between leaky simulations and total simulations.

3.2 Create Flow Property Maps from Cement Maps

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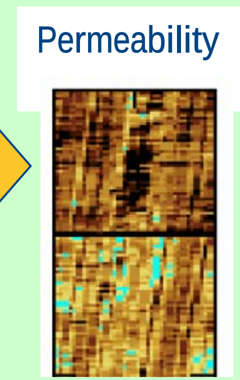
Plug into:

$$k = \frac{d^2}{32b}\frac{\Delta V_L}{V_{L0}}$$



Log and Lab Measurements

Flow Property Map

Summary

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- This project will investigate the relationship between ultrasonic cement properties to flow properties
- Sampling and testing techniques will be used to validate the flow property models
- The flow property models will be used to simulate and examine leakage probabilities and uncertainties in wells
- Will provide some information on the effect of brine on cements prior to CO_2 injection

6th IEA Wellbore Integrity Network Meeting

Session 3: Projects and Practical Experiences

CO_2 EOR Well Remediation

M.E. Parker, ExxonMobil and R.E. Sweatman, Halliburton

American Petroleum Institute CCS Task Force

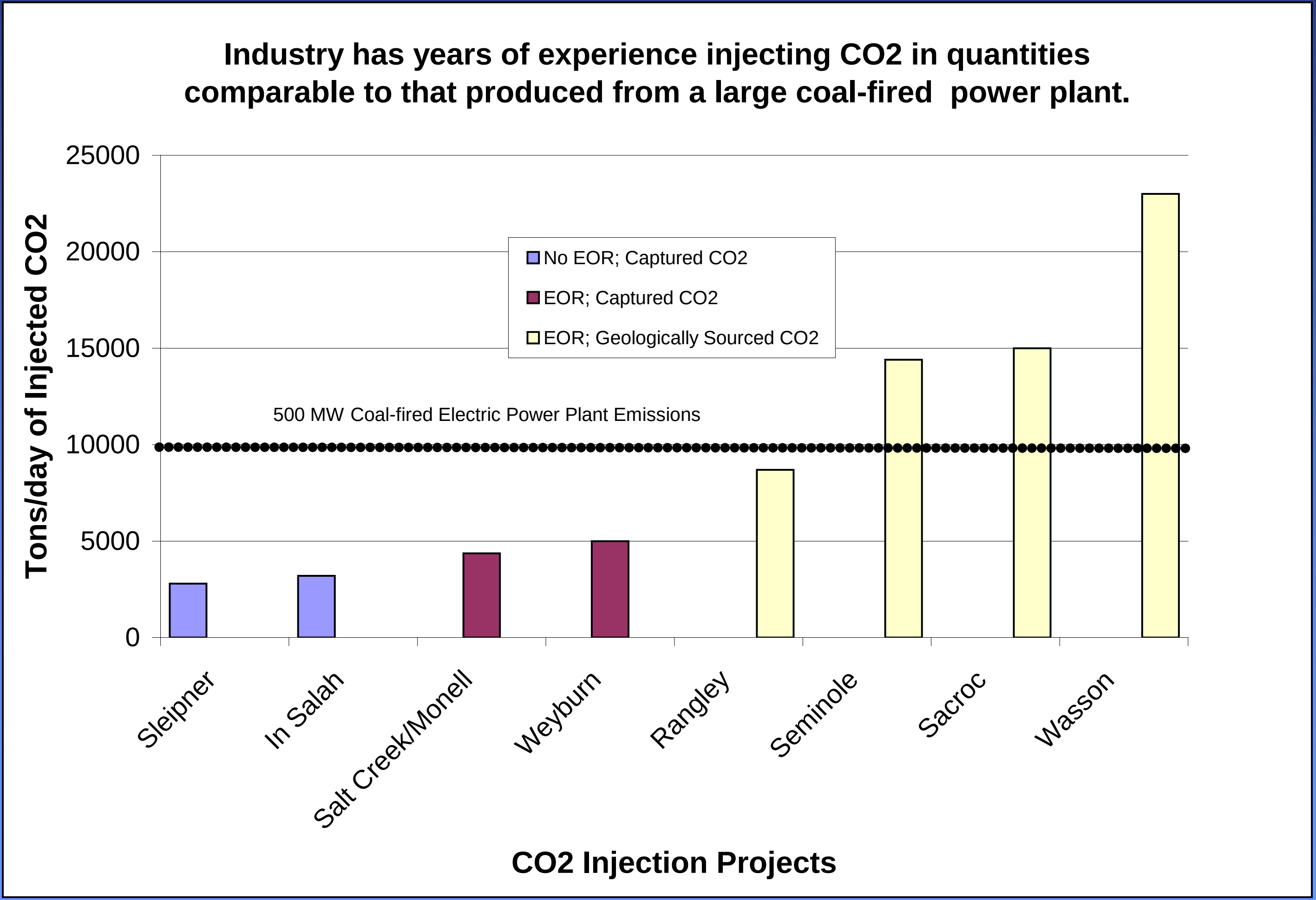
28-29 April, 2010 • Palace Hotel • Noordwijk, The Netherlands

Great Success!

- 40 years of experience
- Safe and environmentally friendly
- Large scale operations
- 655 Millions of tons CO_2 geo-sequestered

CO_2 EOR Facility in Carmito, Mexico
Separates, Compresses, Distributes CO_2

CO_2 Injection Projects

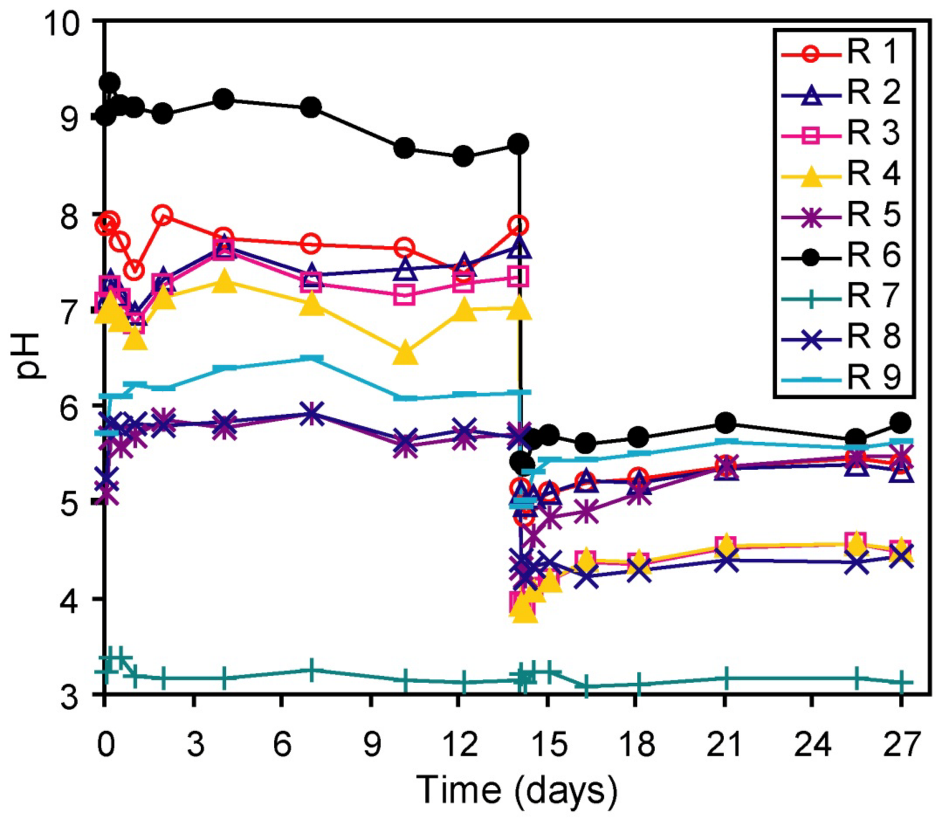


HSE Performance

- More than 15,000 wells (94% in world)
- Monitored, measured, verified,
- And documented–for 4 decades
- Operational flow incident frequency rate: estimated 0.0087% of wells per year
- No significant leakage issues
- Sporadic, minor leaks remediated

CCS and CO_2 EOR Studies

Simulated geochemical conditions in laboratory tests of pH values vs. time (GCCC/BEG/UT) show higher than expected pH conditions due to buffering by reservoir fluids and formation surfaces

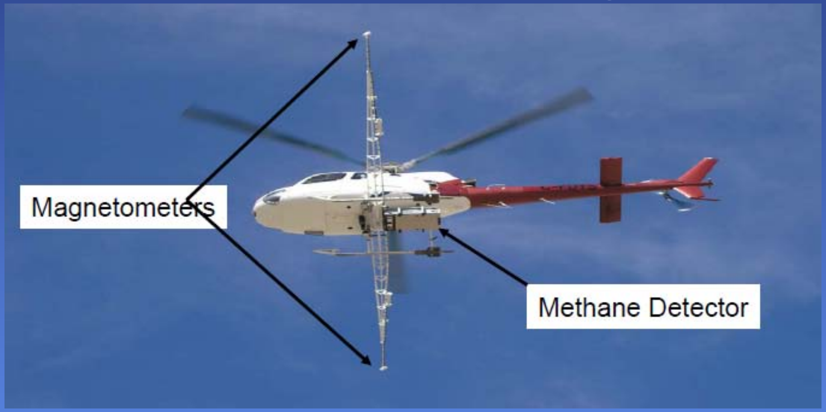


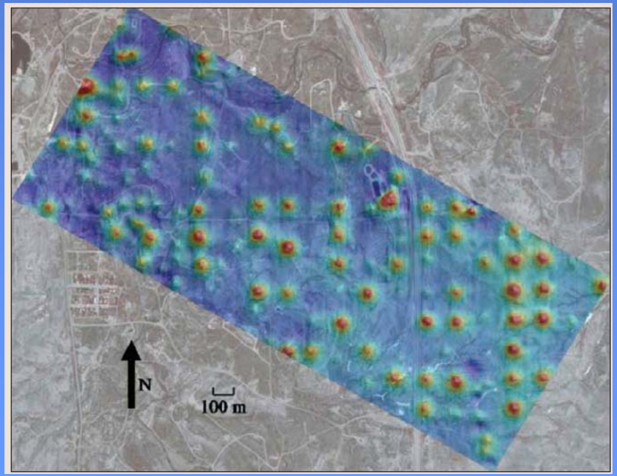
Well and Reservoir Integrity

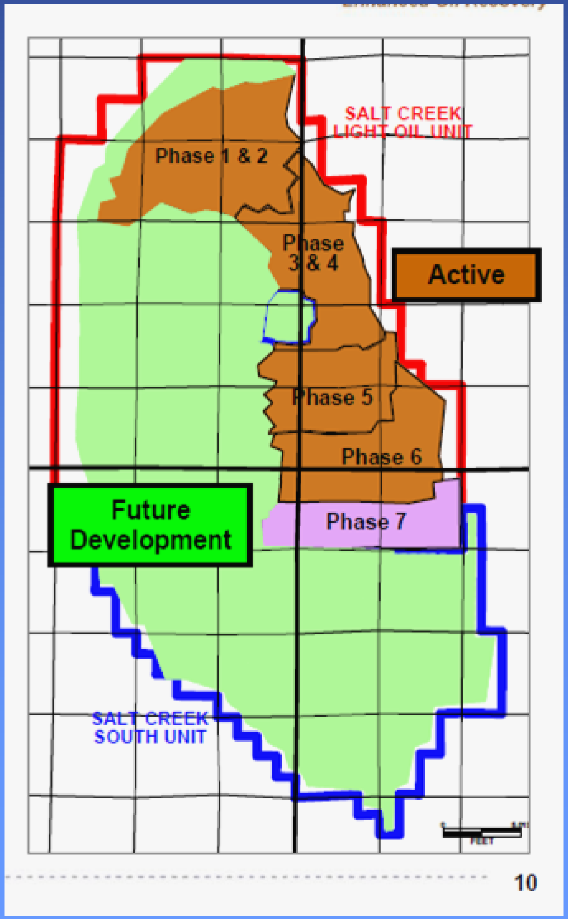
- **Monitoring, inspection, modeling tools**
  - Slick-line casing/tubing inspection (impression block, camera, etc)
  - Wireline-conveyed logging tools (spinners, etc)
  - Seismic array surveys & imaging
  - Wellbore pressure & temperature data modeling
  - Flow meters for mass balance
  - Micro-deformation measurements & imaging
    - Surface & downhole tiltmeters
    - Satellite-based interferometric synthetic aperture radar
  - CO_2 flow predictions via reservoir engineering models
    - Benchmarked and calibrated by monitoring data
    - Periodically verified by monitoring data

E&P remediation technologies for CCS wells

- Magnetometer surveys locate old/unrecorded wellbores
- Barrier wells use water injection to control plume movement



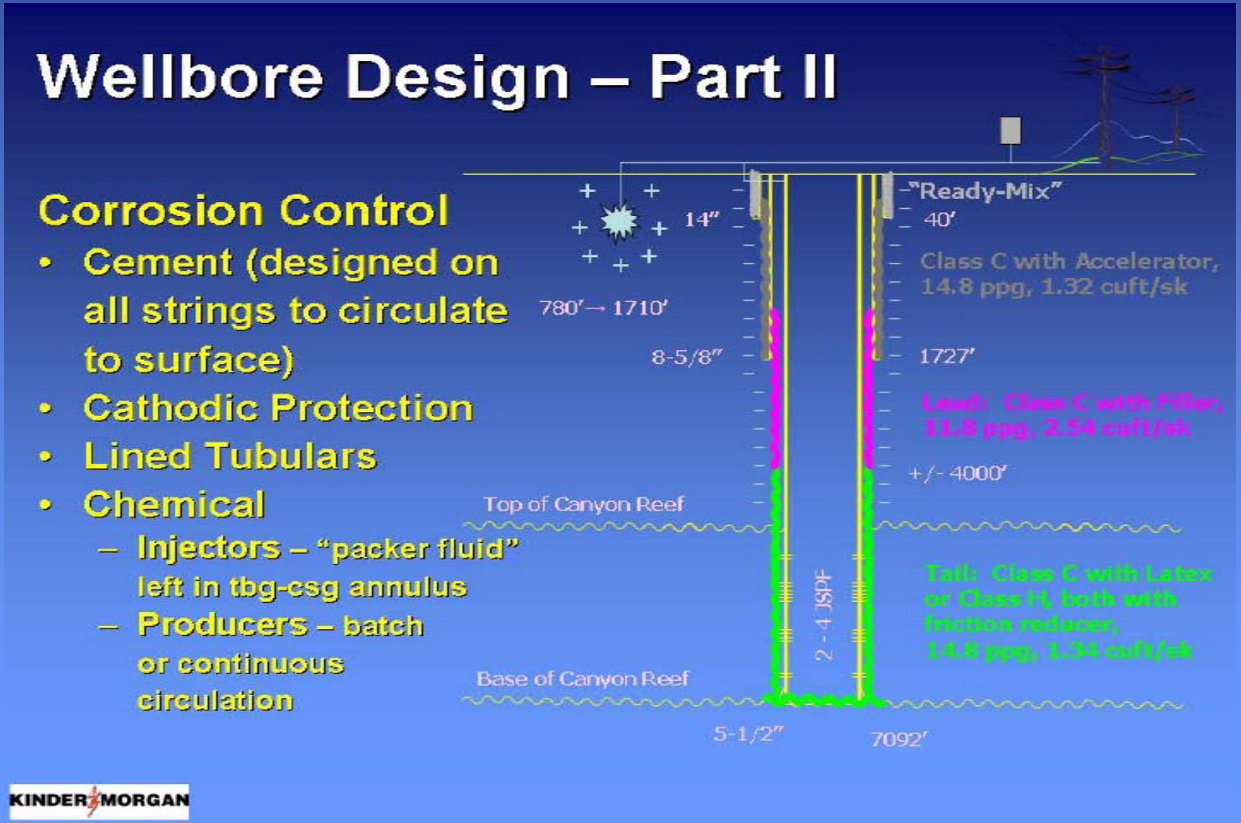




Photos from Anadarko

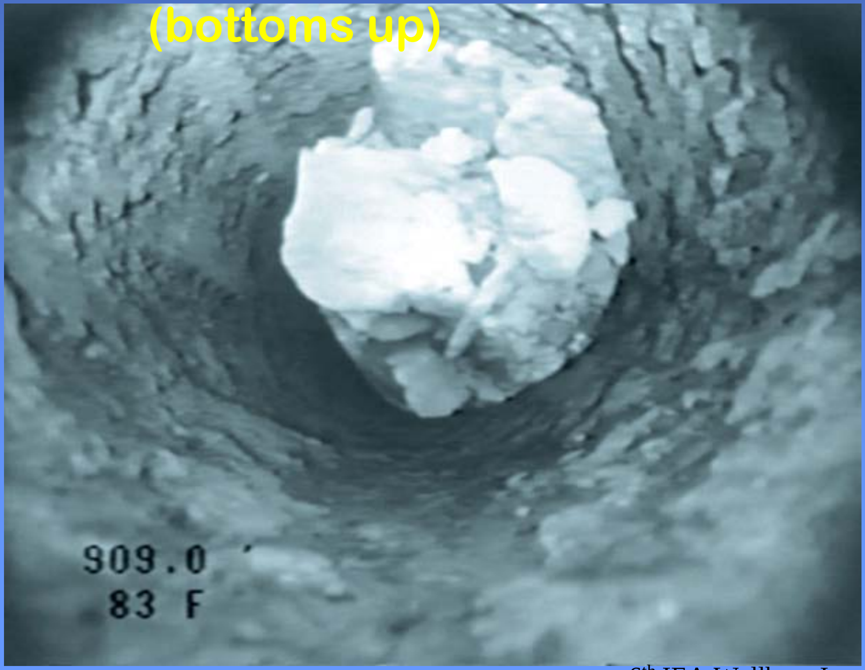
E&P remediation technologies for CCS wells

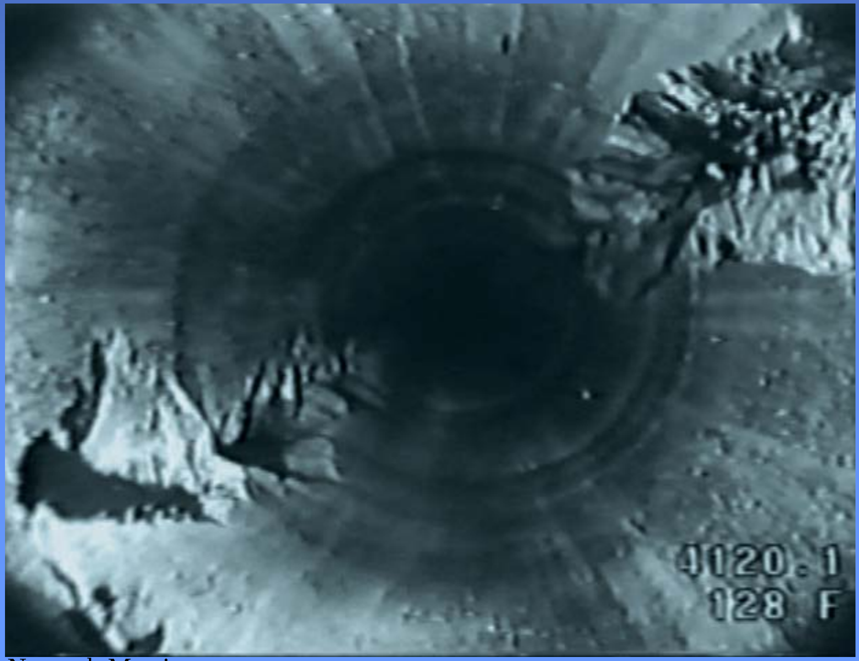
- **Remediation of problems: re-P&A, tubing & casing leaks (MIT failures), behind casing communications, caprock seal integrity failure (faults/fractures perforated interval flow-control, and CO_2 mobility control for sweep efficiency**



Remediation

- Challenge: Re-Plugging old wells
  - Old P&A standards may not meet needs for CO_2 EOR or CCS
- Solution:
  - Standard wellbores: re-enter, drill out old plugs, clean wellbore to adequate depth, MIT & diagnostic logs, re-plug with cement, re-test each
  - Non-standard (sub-grade pipe, cement, etc) wellbores: re-enter, drill out old plugs, clean wellbore to required depth, MIT + logs, run wireline pipe inspection, mill out damaged casing in required intervals, plug cement at milled-out intervals & those in regulations, re-test each (bottoms up)

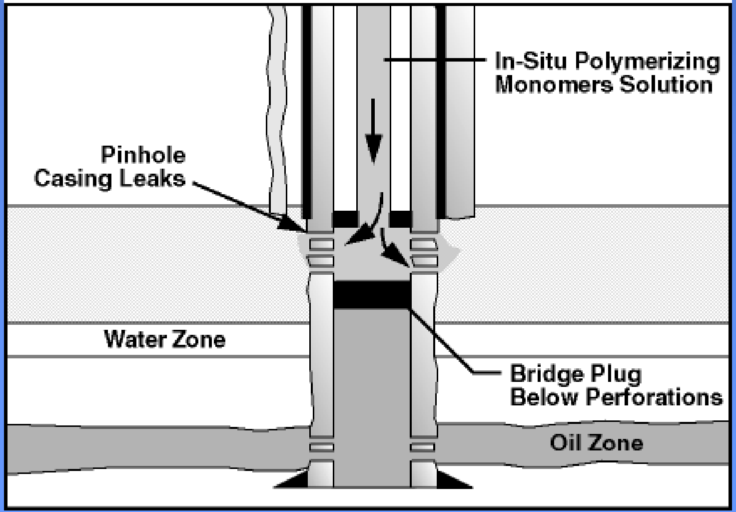




Remediation

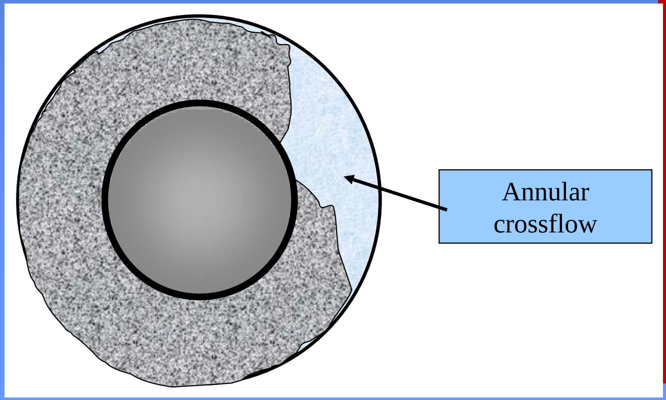
- Challenge: Tubing and Casing Leaks
  - May occur in old and new wells
- Solution:
  - Diagnostics to pinpoint detection: pressure communications, MIT, pipe inspection logs, pulsed neutron or other logs, downhole camera, etc
  - Repair: pull/replace-or-repair/re-run/re-test pipe or squeeze
    - Pipe-repair: casing patches, expandable liners, pipe connections, etc
    - CO_2 resistant cement squeezes
    - Chemical sealants: CO_2 resistant gels, resin systems, etc
  - P&A liner section, drill sidetrack, run new completion
  - Repeat diagnostics to confirm sealing integrity: MIT, logs, etc

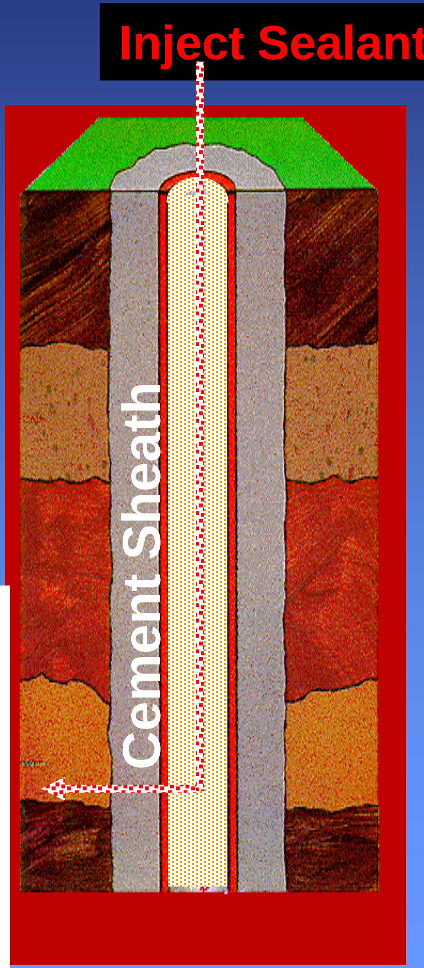
Leaking pipe retrieved



Remediation

- Challenge: Behind casing communication
  - May occur in old and new wells
- **Solution:**
  - Apply diagnostic tools to pinpoint leak flow path
  - Design/Execute
    - Perforating into leak path
    - Treatments (squeeze sealants)
      - CO_2 resistant cement squeezes
      - CO_2 resistant chemical sealants: gels, resin systems, etc
  - Repeat diagnostics to validate success

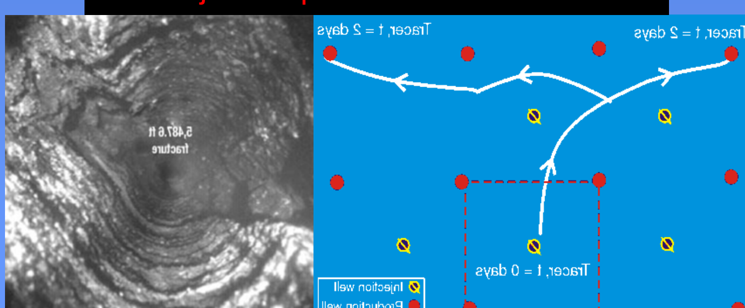


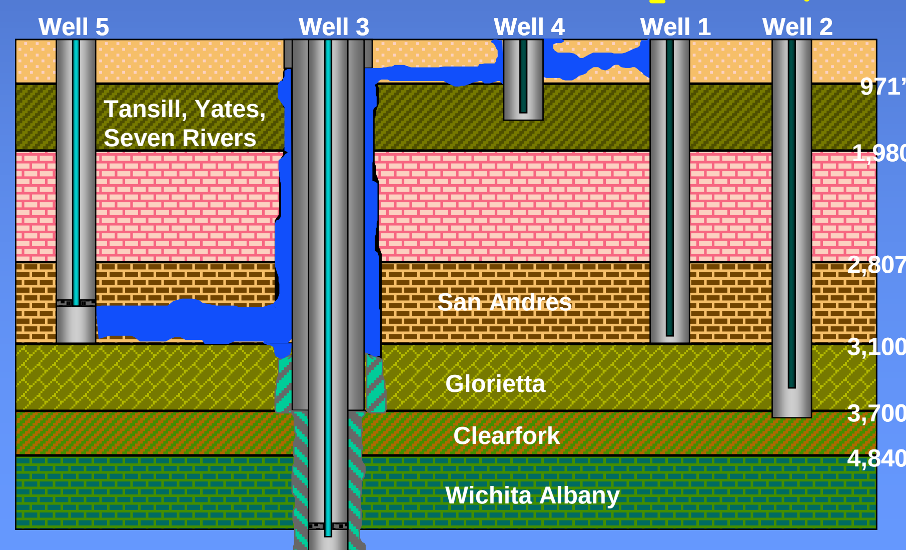


Remediation

- Challenge: Caprock Seal Integrity Failure
  - Leaks via fractures and unsealed faults may occur in some reservoirs
- **Solution:**
  - Apply diagnostic tools (WL logs, seismic, micro-deformation, etc)
    - Pinpoint leak flow path in fracture or fault between wells
  - Design/Execute
    - If needed, coil-tubing drilling into leak path
    - Treatments (squeeze sealants)
      - CO_2 resistant cement squeezes or gel-cement stages squeezed
      - CO_2 resistant chemical sealants: gels, resins, etc
  - Repeat diagnostics to validate success: sealed leak for CO_2 sweep & containment

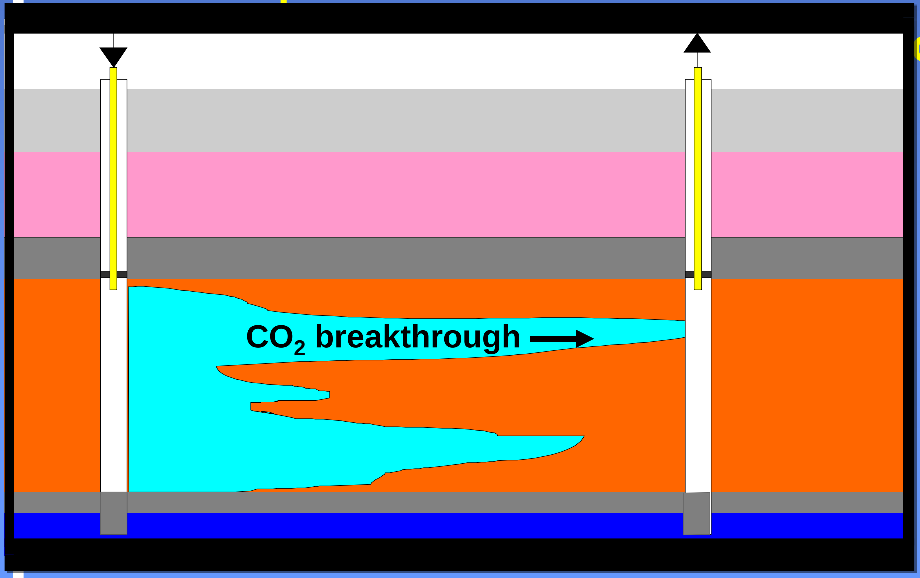
Inter-well communication outside the injection pattern due to fractures

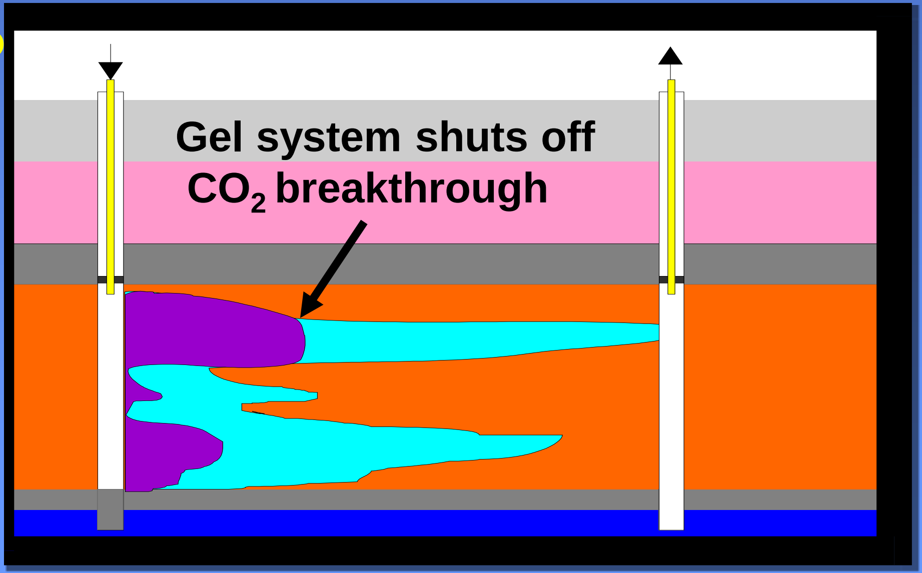




Remediation

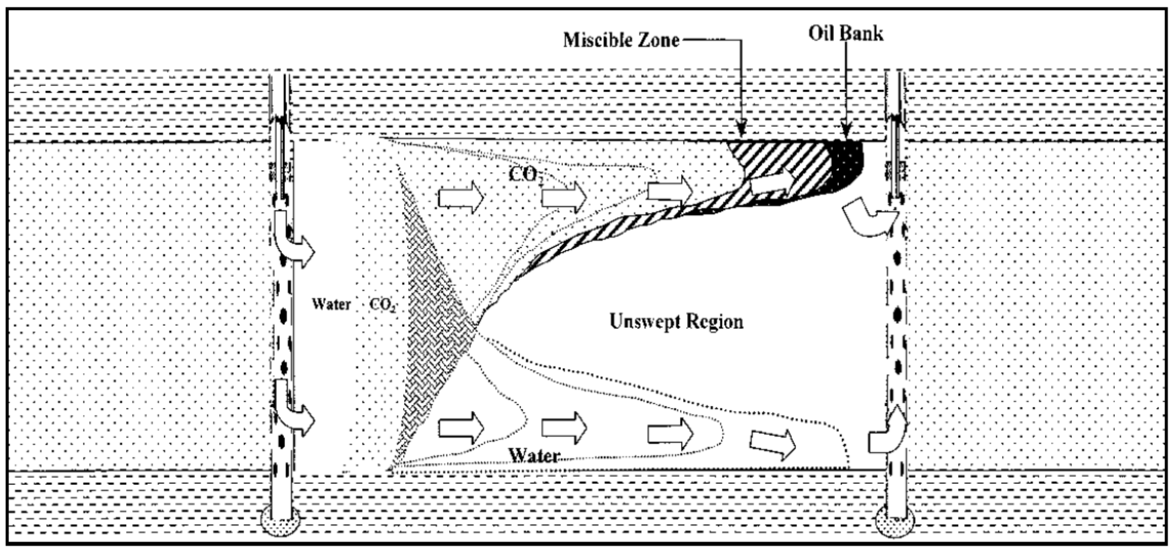
- **Challenge:**
  - Injection/production perforation-flow profile control (sweep efficiency)
- **Solution:**
  - Apply diagnostic tools (modeling, seismic, micro-deformation, WL logs, etc)
  - Design/Execute:
    - Treatments (squeeze sealants)
      - CO_2 resistant cement squeezes to seal perf tunnels
      - CO_2 resistant chemical sealants (gels, resins, etc) to seal perm
    - Mechanical devices: flow control valves, etc to control flow into perfs





Remediation

- Challenge: CO_2 mobility control for sweep efficiency
- Solution:
  - Apply diagnostic tools (Modeling, seismic, micro-deformation, WL logs, etc)
    - Predict or identify poor sweep efficiency
  - Design/Execute
    - Treatments of injected CO_2 with co-injectants and/or fluid stages
      - Mobility control agents: gels, foam, etc
      - Materials to improve miscibility, reduce friction pressure, etc
      - Stages of treated fluids between stages of CO_2: WAG, etc
  - Repeat diagnostic monitoring to validate sweep improvements



Conclusions

- O&G experience is relevant
  - Technologies
  - Scale of injection
  - Isolation integrity

Conclusions

- API best practices
- Current projects prove the point

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Risk of leakage through wellbores: Is it really that high?

Matteo Loizzo[a], Salvatore Lombardi[b], Onajomo Akemu[a], Laurent Jammes[a], A. Annunziatellis[b]
[a]Schlumberger Carbon Services, [b]Universitá di Roma “La Sapienza”

IEAGHG 6th Wellbore Network Meeting
Noordwijk Aan Zee, The Netherlands

2010 Apr 29

Outline of the presentation

Schlumberger Carbon Services

- Analogs to CO_2 storage wells
- Well analogs
  - Major events
  - Well-head pressures and leak rate distribution
  - Leakage pathways
  - Risk profile and leak rate distribution
  - Effect of time
- Natural analogs
  - Distribution and consequences
- Containment monitoring
- Regulation: US and EU
- Conclusions

Carbon storage – well analogs

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- CO_2: high-pressure, light, thin fluid
  - Driving force, buoyancy, low friction pressure drop
    - *"Only when pressures are exerted on the well as during fracturing, acidizing, or fluid injection of a flooding operation do some of these [primary-cementing] failures become apparent."* [Scott & Brace, 1966]
  - Methane, steam
    - *"Consideration of CO_2 versus steam injection suggests the abandoned-well blowout rate in CO_2-storage fields may not be dissimilar"* [Preston & Benson, 2008]
    - Methane Lower Explosive Limit → 5%
    - High pressure water → water injection, hydraulic fracturing?
- Wellbore integrity
  - Leaks through cemented wellbores
  - Excluding well control incidents and tubing leaks

Well analogs – major and catastrophic events

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- Underground Gas Storage (UGS), depleted reservoirs and aquifers
  - [Evans, 2009], worldwide – see table
    - Events with wellbore integrity issues 27% of total
  - Using [Papanikolau, 2006] and [Keeley, 2008] ⟶ estimate of 705,536 well-years of operation
    - $2.0\ 10^{-5}$ major events per well-year, $2.8\ 10^{-6}$ if only casualties are considered

		Total events	Events with casualties	Events with fatalities
O&G reservoirs	All	27	5	0
	Wells	*11*	*2*	*0*
Aquifers	All	24	3	1
	Wells	*3*	*0*	*0*
Total UGS analog events		*14*	*2*	*0*

- Steam injection, [Jordan & Benson, 2008], District 4 in California
  - Wells in operation, thermal fields ⟶ $7.3\ 10^{-5}$ major events per well-year
    - $9.5\ 10^{-6}$ for non-operational wells (7.7 times less)
  - No fatalities

Well analogs – SCP occurrence

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Large sample studies

[Marlow, 1989], survey	6.1% of c. 7,000 UGS wells in the USA Leakage rate: 61% of wells leak <35 t/y; 90% of wells <200 t/y,
[Burgoyne et al., 1998]	11.6% of c. 30,000 wells in the Gulf of Mexico leak through casing strings
[Watson & Bachu, 2009]	9.8% of c. 20,000 wells in the Test Area in Alberta 6.3% of wells leak gas through the soil (GM) → almost 1:1 ratio to casing leaks

Smaller samples, anecdotal studies

[Watters & Sabins, 1980]	15% of 250 casing strings
[Xu & Wojtanowicz, 2001]	85% of 26 wells (Gulf of Mexico)
[Chilingar & Endres, 2004]	75% of 50 wells in Santa Fe Springs oilfield

Note: Sustained Casing Pressure (SCP)=Surface-Casing Vent Flow (SCVF)

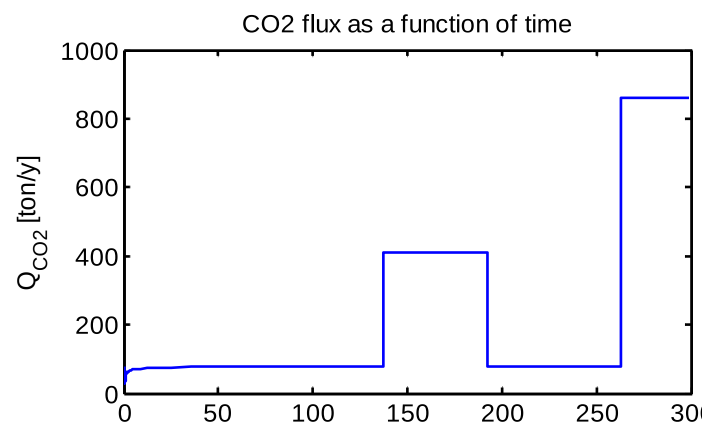
Well analogs – leak rates, 1

- Risk ← loss
  - Little dependence on actual rate, but rather on leak hitting a "target" (exposure)
- In general, leak rate data rare and less reliable than pressure
- Continuous leak rate and instantaneous leak rate
  - Most major leak events involved slow charging aquifer and sudden larger releases

- [Evans, 2009] reports data on a number of UGS leaks
  - Leidy Field (PA, 1969), depleted O&G field
    - Low-level charge of aquifer at 208 t/y (through 5 wells)
    - Sudden blow-out at 14,000 t/y after subsequent parting of 30 wells
  - Kalle (Germany, 1999) → max 15,000 t/y over extended period, probably via 2 wells
- [Araktingi et al., 1984] study on leak in Leroy UGS (WY)
  - 1,900-2,300 t/y through possibly 2 wells and caprock, bubbling at surface
- Tek estimate of leakage from Playa Del Rey UGS at 1,900 t/y
  - 1,900 t/y =100 Mft^3/y → anchoring?

Well analogs – leak rates, 2

- [Burgoyne et al., 1998], case history 1
  - Well leaking ~**35,000 t/y** through $9\frac{5}{8}$” casing (10,000 ft deep)
    - *“Very low rate […] on the order of supply gas releases […] and pilot lights”*
    - Possible mistake → either MCF/Y or TCF/D (**35-100 t/y**)
- [Allison, 2001] detailed review of Yaggy leak (Hutchinson, KA)
  - Storage in salt caverns, leak possibly through hole in casing during re-drilling, 2 fatalities due to explosion & fire
  - **2,716±437 t** lost, possibly most of it leaked through 2 short events and relief wells → instantaneous rate ~100,000 t/y
- [Marlow, 1989] survey
  - Leak rate >1,400 t/y → <7% of sample
- CO_2 leaks
  - [Loizzo et al., 2009], Kaniow CO_2 injection well
    - Migration rate inferred from logs → **100-800 t/y**



CO_2 flowrate vs. time (days) from Kaniow well, [Loizzo et al., 2009]

Wellbore leaks – pathways

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- Four broad classes of leakage pathways:
  1. Placement – liquid cement → <u>mud "channels"</u>
  2. Cement setting → "chimneys", gas and brine
  3. Solid cement → "microannuli", and possibly cracks
  4. *No cement – trivial pathway*
     - Possible cause of brine flow into Navajo aquifer (Utah), from EPA report
- Channels broadly solved by the O&G industry in the 1990's
  – Sharp drop in leak rates in Alberta in 1990?
  – <u>Gas</u> chimneys qualitatively understood and reduced by improved practice
  – Technology can help drive down leaks
- Leak rates strongly dependent on well risk → geology <u>and</u> drilling
  – SCP >2x likely in the Test Area than in the whole of Alberta
- All major leaks include accumulation and transport through "imperfect collector zone" → shallow aquifers

Well analogs – risk profile

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- Risk assessment based on frequency data presented
  - Leaks to surface → ~10% through casings to well-head, 10% through soil
    - Prevalence of subsurface fluid migration (e.g. SACROC)?
    - Leaks happen very early, but assuming well life of 10 years → frequency of 2 10^{-2} events/well/year
    - Serious events
      - Cost around $10-50K at some point during well life, even though they don't result in immediate intervention
  - Major leaks: 5 10^{-5} events/well/year
    - No catastrophic event recorded → assumed to be <10^{-6} fatalities/well/year
    - Considered acceptable limit for general public → likelihood of lightning strikes (1.7 10^{-7})
    - *"No [drinking water] or atmospheric endangerment by CO_2 emissions from CO_2 EOR projects"* [Sweatman et al., 2009]
- Maximum Criticality Severity → small surface leaks (SCP/GM)
  - Severity causing maximum loss, reference for risk management

Risk profile – implications

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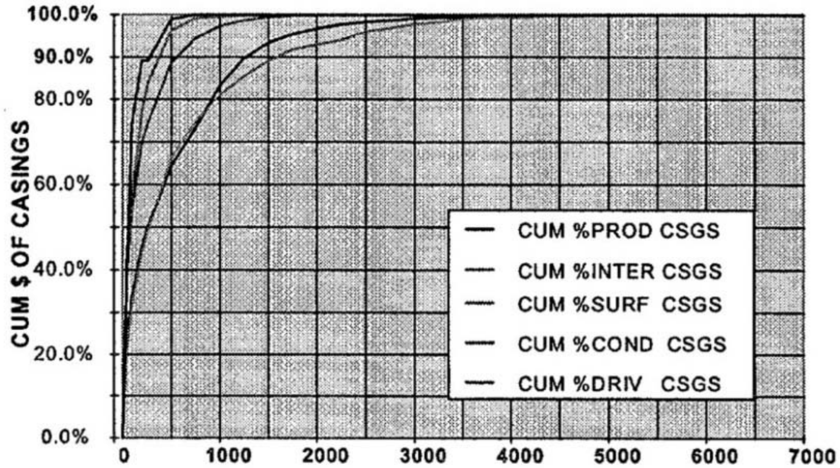
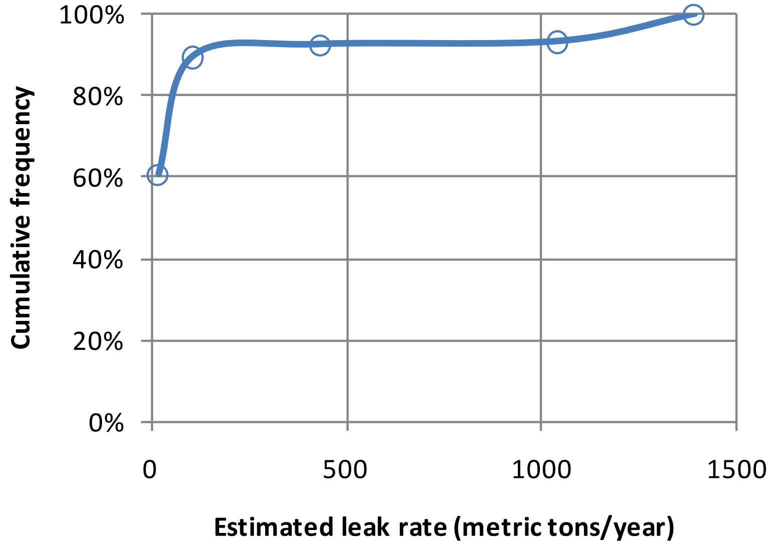
- HSE analogy
  - Stepping, handling and lifting vs. driving or pressure
  - Most events have relatively benign outcomes → sprained ankles or cut fingers
- Medical analogy
  - Seasonal flu vs. tumors
  - Flu → widely spread, yet very seldom fatal
    - 30 million outpatient visits every year in the US alone
    - Exercise reasonable prevention, see doctor if complication, vaccine every Fall
  - Tumor → less common, but potentially fatal
    - Intensive prevention, frequent tests, immediate reaction, tolerance for false positives
- Acceptable risk → at most one-off awareness training, general procedures
- ALARP → must evaluate risk before every exposure, specific design
  - No general solution, every field/well should be optimized

Well analogs – SCP and leak rate distribution

Schlumberger Carbon Services



Pressure (psi) distribution by occurrence in each casing type from [Burgoyne et al., 1998]

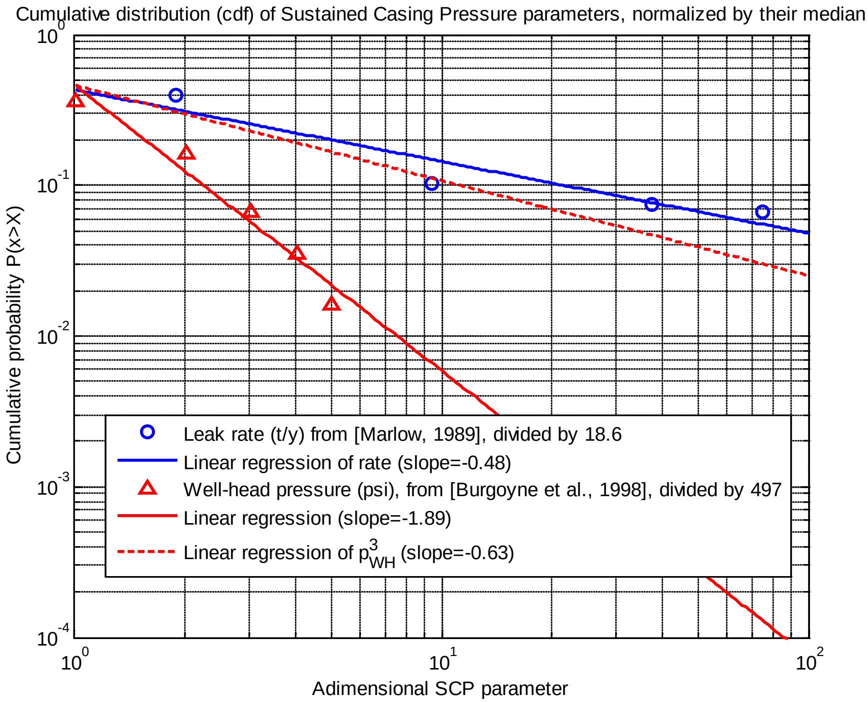


Leak rate distribution from survey, modified from [Marlow, 1989]

- Gas production well → mass flow rate roughly proportional to well-head pressure
  - $Q \sim p_{WH}^3$ if flow in fracture instead of permeability
- [Araktingi et al., 1984] study on leak in Leroy UGS, leakage fitted to $Q \sim p_{BH}^2$
  - Very narrow pressure range (60 psi around 1,800 psi) and exponent 2 assumed
- [Burgoyne et al., 1998], case history 1
  - 4,400 psi SCP, consistent with gradient used in order of magnitude calculation

Well analogs – leak rate distribution

- Cumulative distribution of leak rate and well-head pressure approx. linear on a log-log scale
  - Similar slope of leak rate and third power of p_{WH} → possible effect of flow in fracture?
  - Power law exponent ~-1.5
    - Leaks 10 times bigger are 3 times less likely
    - Gutenberg-Richter law for earthquakes → 10 times bigger, 10 times less likely (exponent -2)
- Even with standard O&G technology, <2 wells in 1000 will leak >10,000 t/y
  - Major events → 10,000-100,000 t/y
  - Would take 1,500 years to accumulate CO_2 released from Lake Nyos



CO_2 leaks – effect of time

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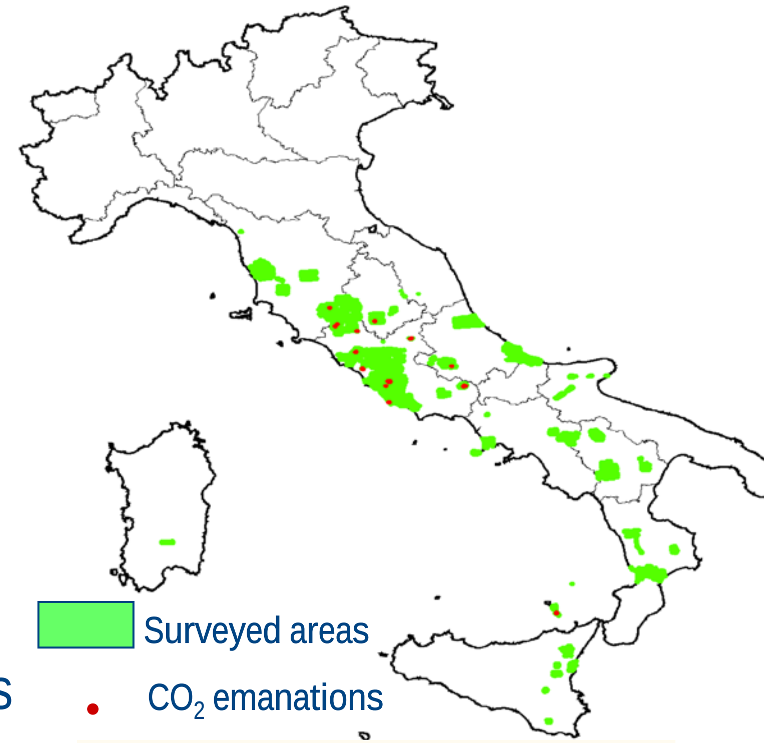
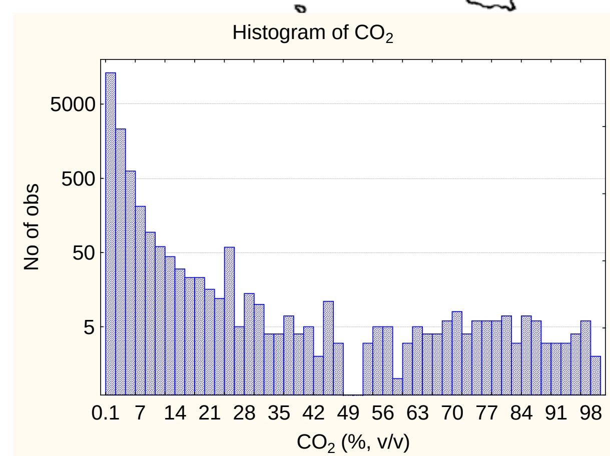
- Cement
  - Strong reaction → carbonation, reversal of calcination
  - Change in mechanical and transport properties, formation of fronts
  - Possibly degradation, maybe pathway healing under some conditions
    - Need for modeling, representative transport/reaction experiments, detailed observations
- Steel
  - Strong reaction → uniform “sweet” corrosion
  - Very fast degradation (~1 year) in the absence of protective layers or Corrosion Resistant Alloys
  - Very limited research
    - Cement effective protective layer, what about carbonated cement?
  - If cement is present, risk may not increase. If cement is absent, risk will increase quickly

Natural analogs – distribution

- Gas migration studied in Italy for >25 years
  - From volcanic & geothermal areas and oil & gas fields
- Total area covered by CO_2 soil gas surveys $\longrightarrow$ 4,000 km^2
  - CO_2 in soil air above 20% over 0.15% of area
  - Above 60% over 0.025% of area (1 km^2)
  - 50% of samples with concentration <2%
- Total area covered by He-4 soil gas surveys $\longrightarrow$ 12,000 km^2
  - He-4 >500 ppb above atmospheric content over 2.5% of area
  - He-4 >2000 ppb above atmospheric content over 0.03% of area (4 km^2)





Natural analogs vents – CO_2 flux from Latera (Italy)

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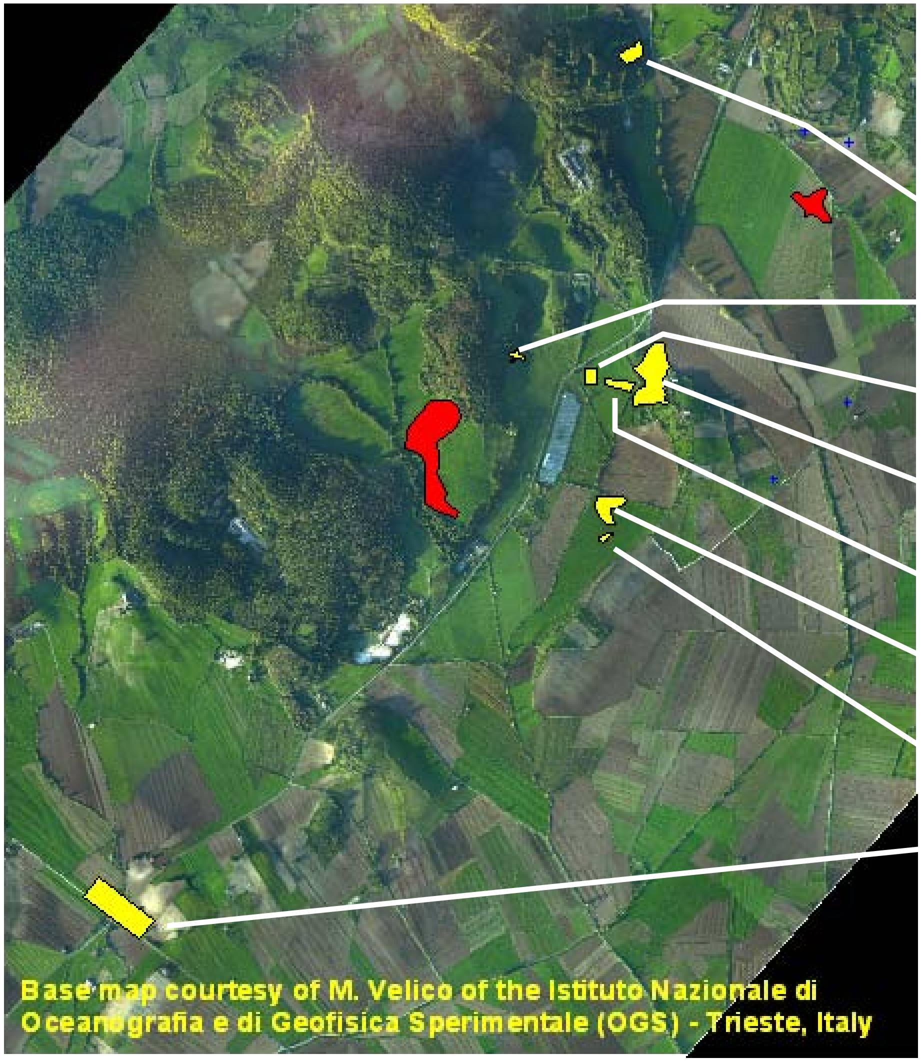

site	CO2 flux (g/d)
1	6599818
2	87162
3	145784
4	6471988
5	69159
6	35547
7	199989
8	7544034
total	21153480

3 locations account for 97.5% of CO_2 flux

~7,700 t/y

Natural analogs – consequences

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- Natural leaks concentrated over small area
- Very little disruption on ecosystem or human activity
  - Photo from Latera caldera showing effect of CO_2 leak on vegetation and prints of sheep from nearby flocks possibly drinking at mineral water puddle
  - Kaolin quarry (with disused mineshaft) around actively degassing fault
  - Total flux from Latera caldera→ ~0.01-0.1 Mt/y

CO_2 bubbling inLatera caldera (Italy) with sheep prints around the puddle, courtesy of B. Lecampion

Containment monitoring

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- Part of the site monitoring plan
- Verification monitoring → prevention
  - Ensure integrity of the vertical barriers is preserved
    - Update risk profile → prevention measures
- Assurance monitoring → mitigation
  - Detection of migration and leaks
  - Quantification of leaks
    - Emission credits
    - Leak detection threshold
  - Monitoring of HSE consequences of a leak
    - Air, potable aquifers, mineral resources

Risk Management: Loss of performance in Injectivity, Capacity, Containment	Minimal Costs: For each technique, For the overall plan over time
Abide Laws & Regulations: Storage safety, Credit allocation, Environmental Impact	Site & technical constraints: Deployment restrictions, Tools sensitivity

US and EU regulation

US EPA 40 CFR parts 144 and 146	EU directive 2009/31/EC
Application for storage permit must include delineation of area of review and a "**corrective action plan**"	Application for storage permit to include "**proposed corrective measures plan**"
Identify all artificial penetrations in the area of review (AoR)	In the event of **leakages**, the operator must immediately notify the competent authority, and take the necessary corrective measures, including measures related to the protection of human health.
Compile, tabulate, and review available information on each well in the AoR that penetrates into the confining system,	The corrective measures shall be taken as a minimum on the basis of the **corrective measures plan**
Identify the wells that need corrective action to prevent the movement of CO_2 or other fluids into or between USDWs.	The competent authority may at any time require the operator to take the necessary corrective measures…additional to or different from those laid out in the **corrective measures plan**.
Perform corrective action to address deficiencies in any wells, regardless of ownership, that are identified as potential conduits for fluid movement into USDWs.	
In the event that an owner or operator cannot perform the appropriate corrective action, the Director would have discretion to modify or deny the permit application. Corrective action could be performed prior to injection or on a phased basis	

Conclusions

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- Cemented wellbores very effective at controlling leak rates
  - Statistical data about analogs (UGS, steam injection) suggest a rate of ~5 10^{-5} major events/well/year, and no fatalities
  - Majority of leaks ~100-1,000 t/y, with at most 2 in 1000 >10,000 t/y
    - Natural analogs suggest very low or no impact
- Small leaks may be frequent for injection wells
  - Possibly 20% of all wells, with about half not showing up at the well-head
  - Risk also depends on geology
- Technology can help minimize leak occurrence
  - Prevention
- Low severity → mitigation can be effective to manage risk
  - Monitor leaks to predict evolution and plan intervention without costly shut-downs
    - “Approval for departure” from 30 CFR 250.517 in the US Outer Continental Shelf
    - Undetected leaks can accumulate and possibly degrade pathways over a long time
- Approach should evolve from “no leak” to “no damage”

Sustained casing pressure analysis as an analog for CO_2 leakage along a wellbore:
Case study results and limitations

Nicolas Huerta, Dean Checkai,
Qing Tao, Steven Bryant

6th Annual Wellbore Integrity Network Meeting
Noordwijk Aan Zee, The Netherlands
April 29th, 2010

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TEXAS

Key findings

- Sustained casing pressure is a useful analog to leakage of CO_2 along a wellbore
- Analysis of field-based case studies provide parameters necessary to model CO_2 leakage
- Understanding magnitude and type of leaks can be used to stochastically estimate an area's leakage rate

Wellbore leakage in the petroleum industry

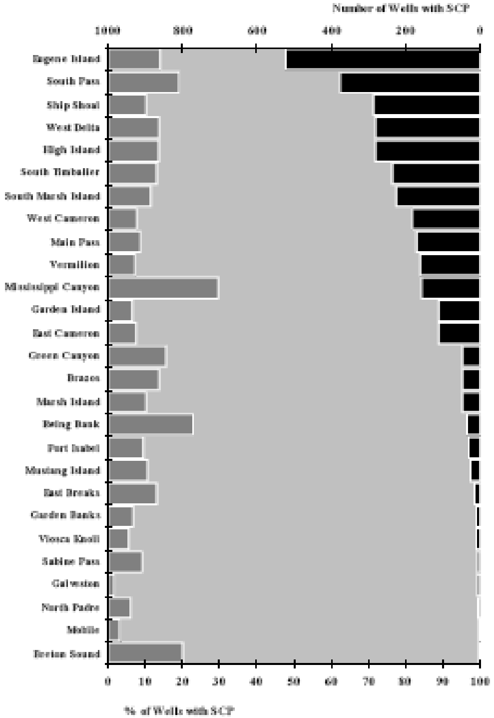
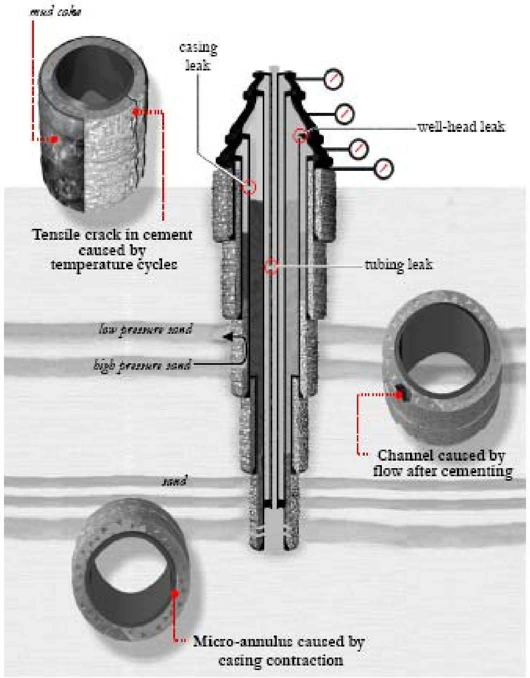
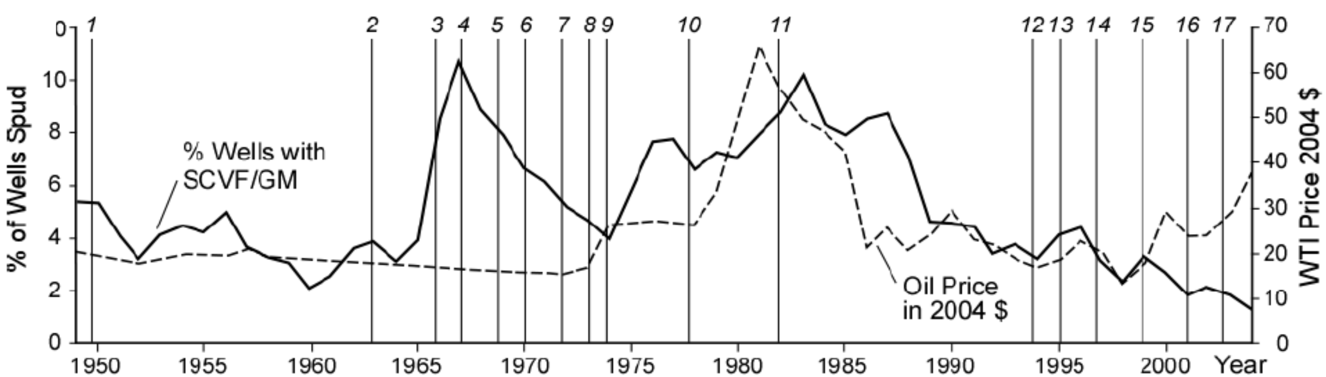


Figure 3.2 : Sustained Casing Pressure by Area



- Leakage of natural gas along wellbores is a persistent problem in the petroleum industry
- Statistics on frequency of occurrence are rare
- Regulations are highly variable
- Most research focuses on prevention or remediation

): Occurrence of SCVF/GM in Alberta in relation to oil price and regulatory changes.



Bourgoyne et al., MMS report

Watson and Bachu, 2007

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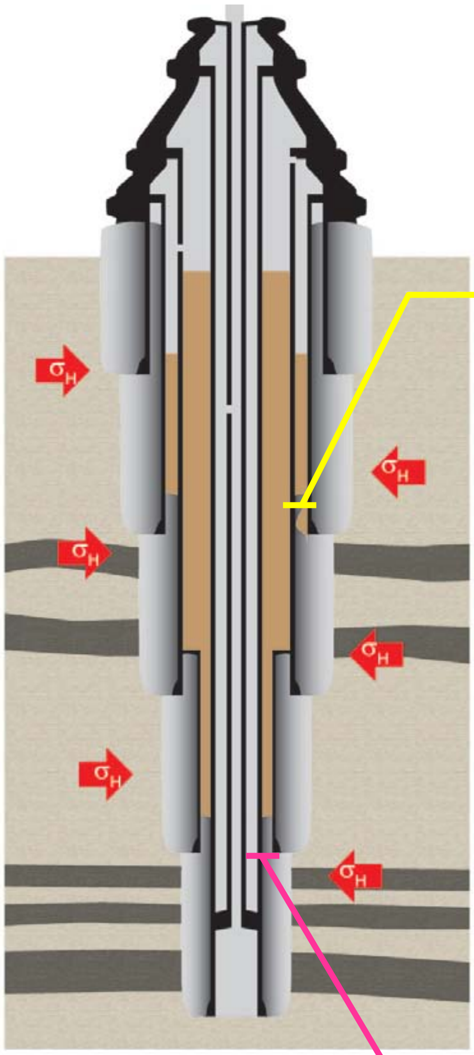
Zonal isolation issues in a well



The most important role cement plays in the oil well is that of *zonal isolation* (Nelson, 2006)

IMMEDIATE & SHORT TERM

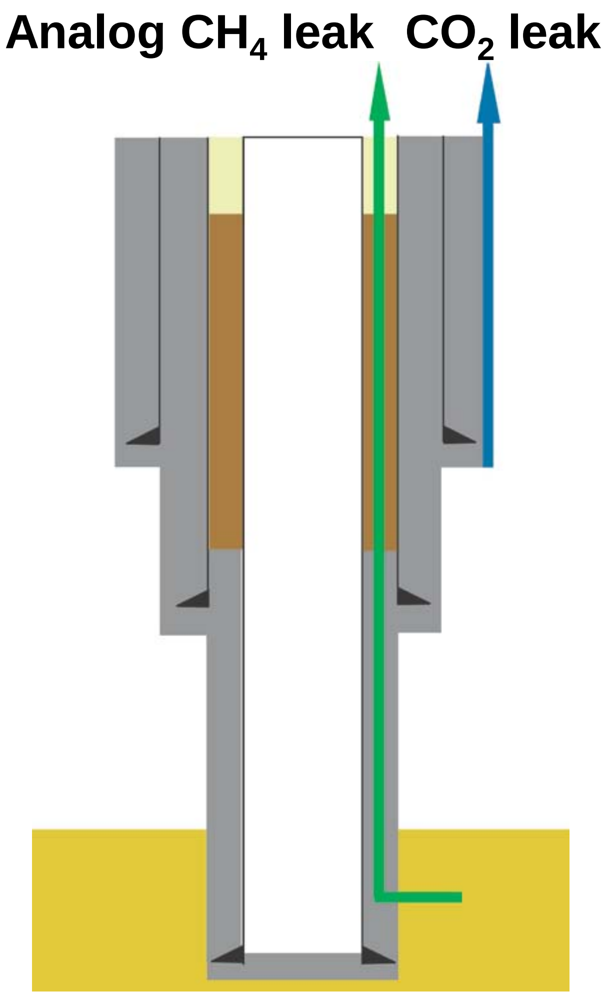
- Channels:
  - Formation pressure >> annular pressure
  - Poor mud displacement
- Micro annulus:
  - Poor mud cake removal
  - Cement shrinkage
- Matrix permeability:
  - High water to cement ratio
  - Low density cement

LONG TERM

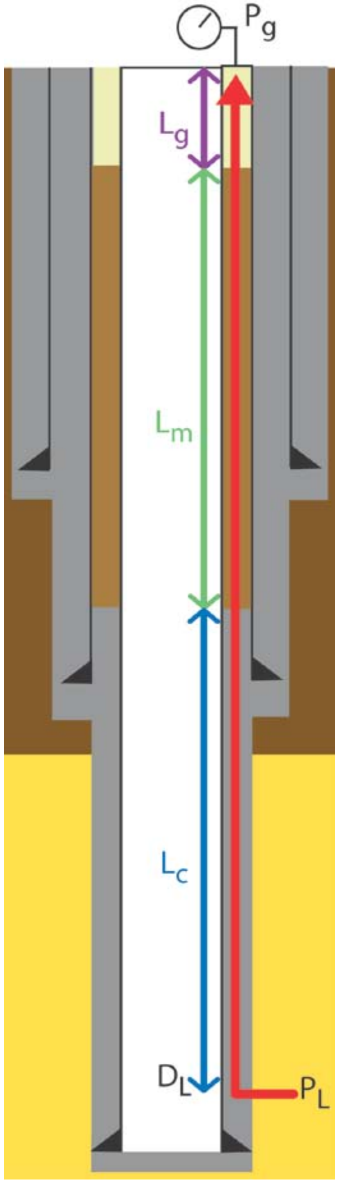
- Any of the above, when subject to high pressure gas exploiting a defect in the cement (Dusseault et al, 2000)
- Mechanical failure due to pressure and temperature extremes

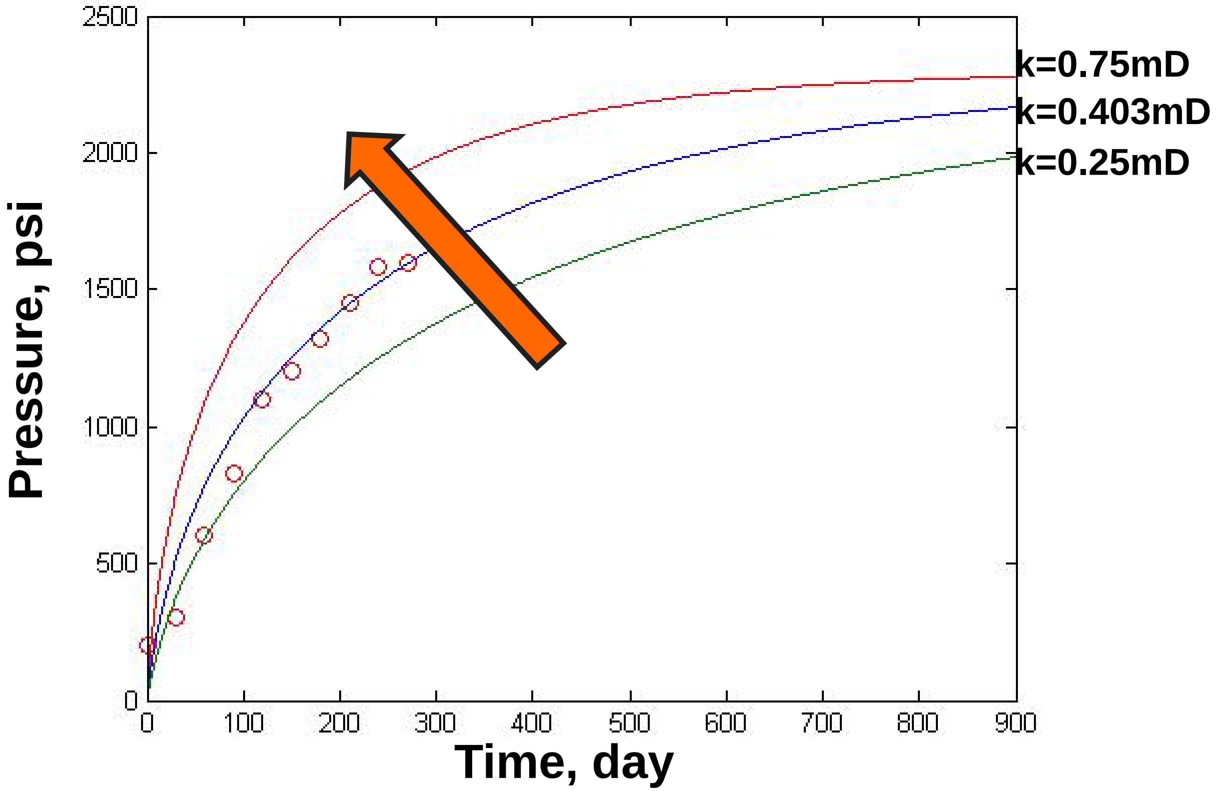
Wellbore leakage of CO_2

- Importance, current understanding, knowledge gaps
- Analogs, experiments, and modeling
- This study
  - propose an oil industry analog that can provide model parameters



Sustained casing pressure model





- If $\rho_m \times g \times L_m + P_g < P_L$: Gas flow occurs
- Buildup rate controlled by effective permeability of cement
- Pressure plateau controlled by P_L and the density and height of the mud column

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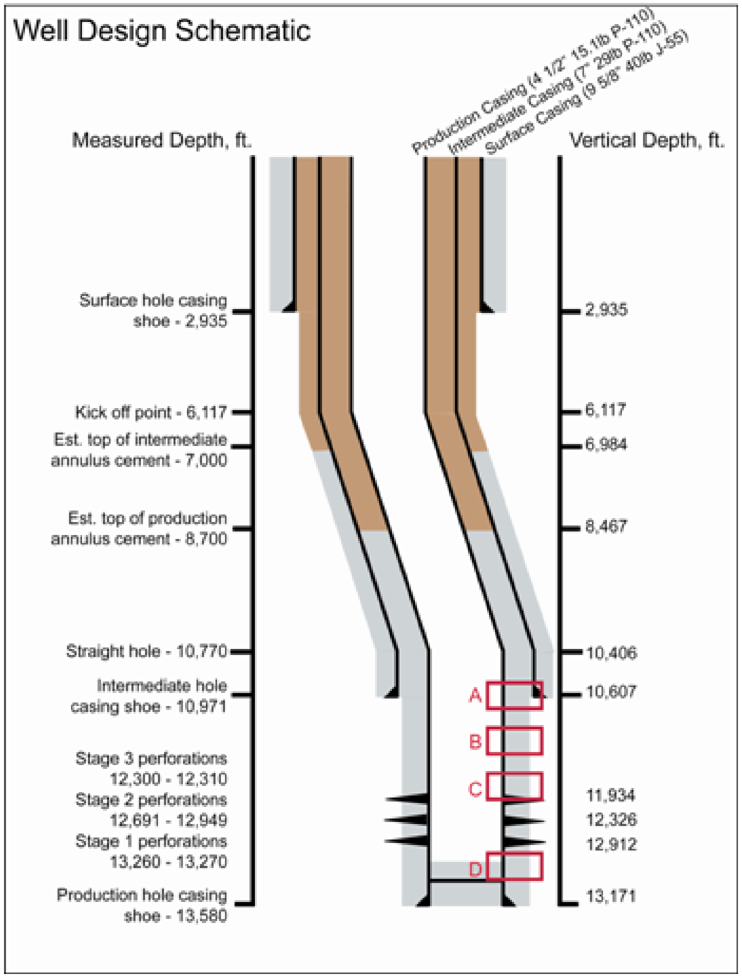
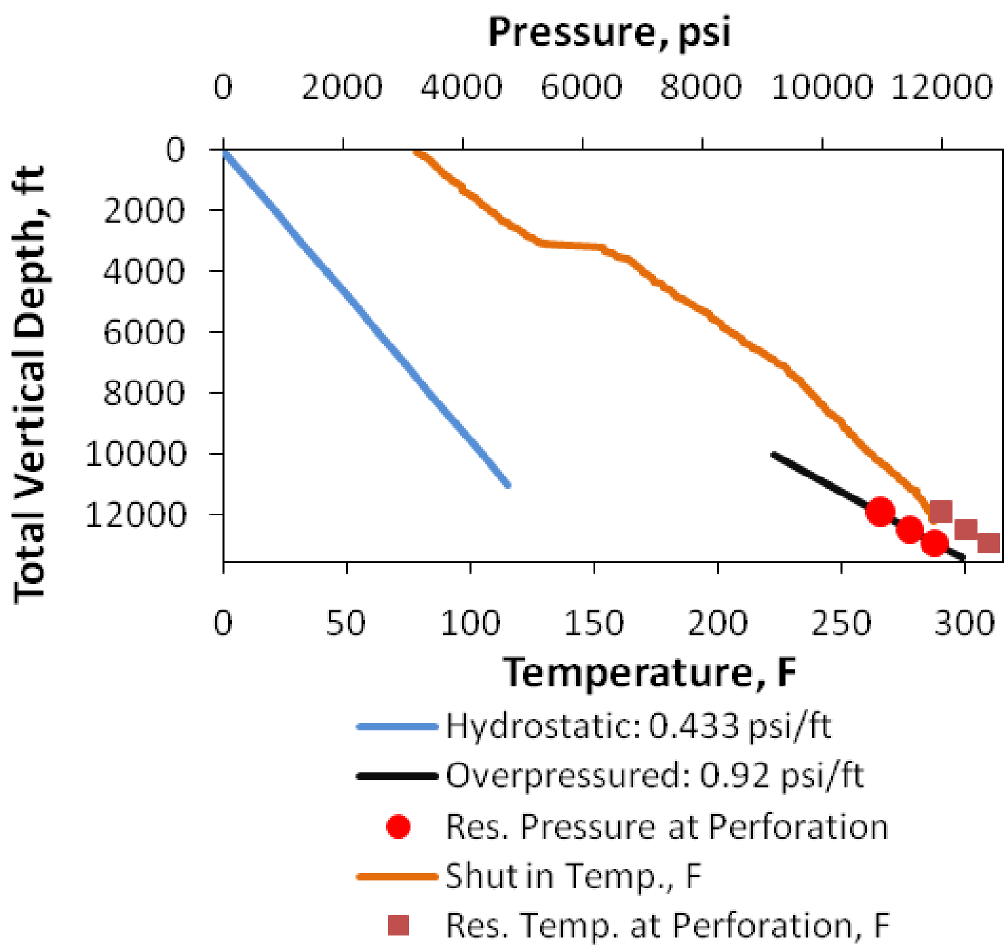
Case study 1

Onshore high pressure high temperature gas well

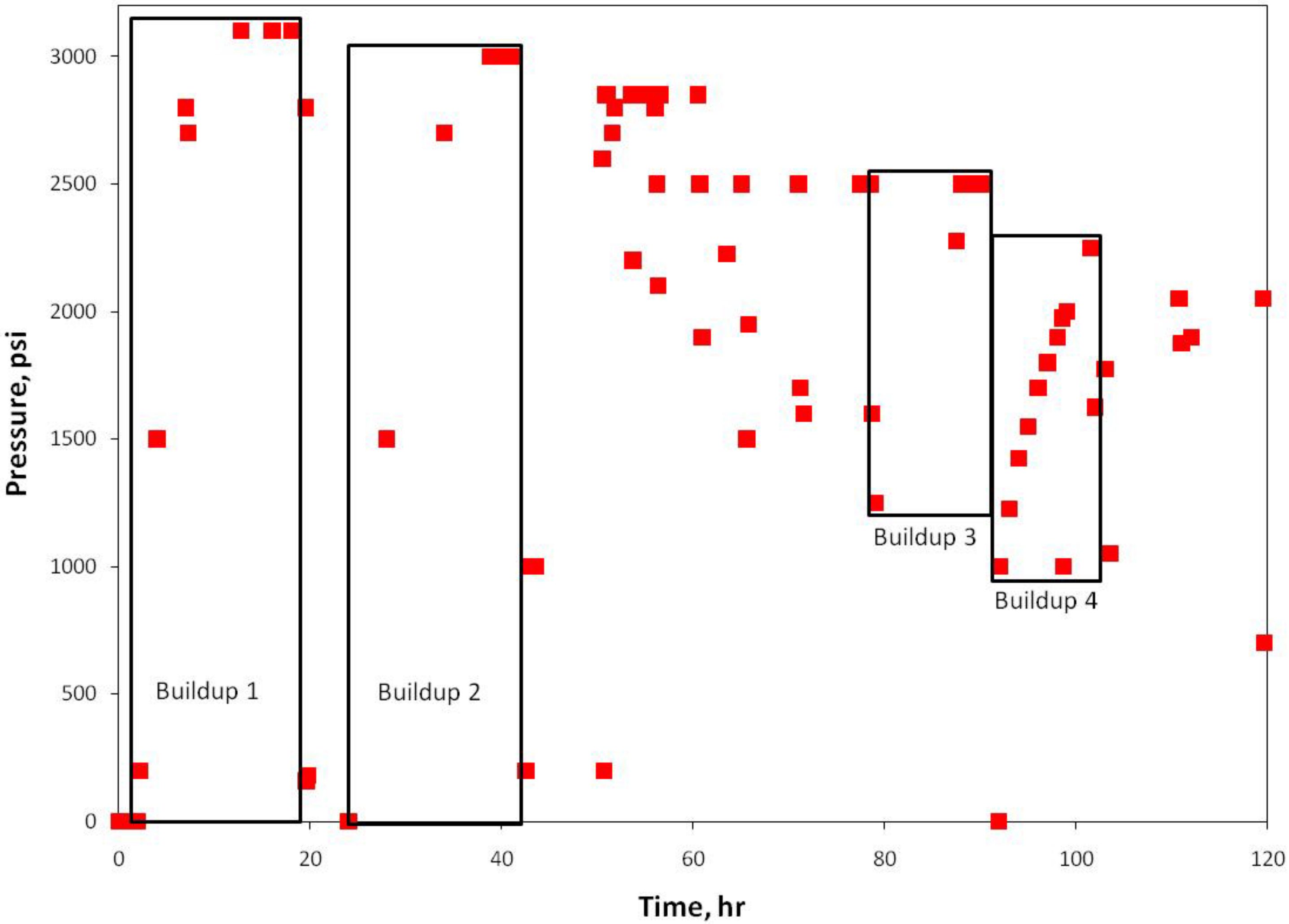
- pressure on annulus immediately after cementing intermediate annulus
- data allows estimate of leakage depth and pathway permeability

Wellbore geometry and key parameters





Pressure versus time data was recorded for several buildups



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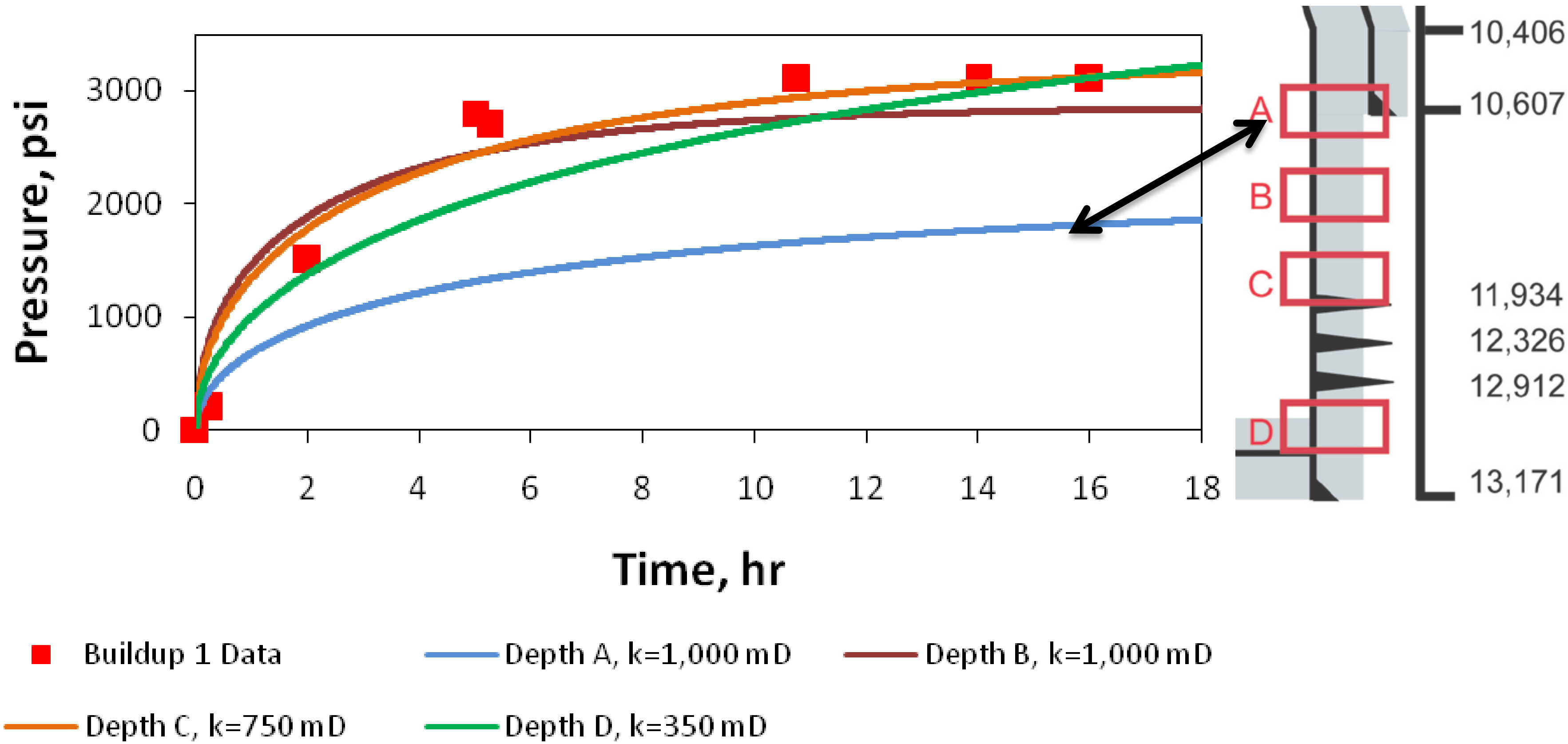
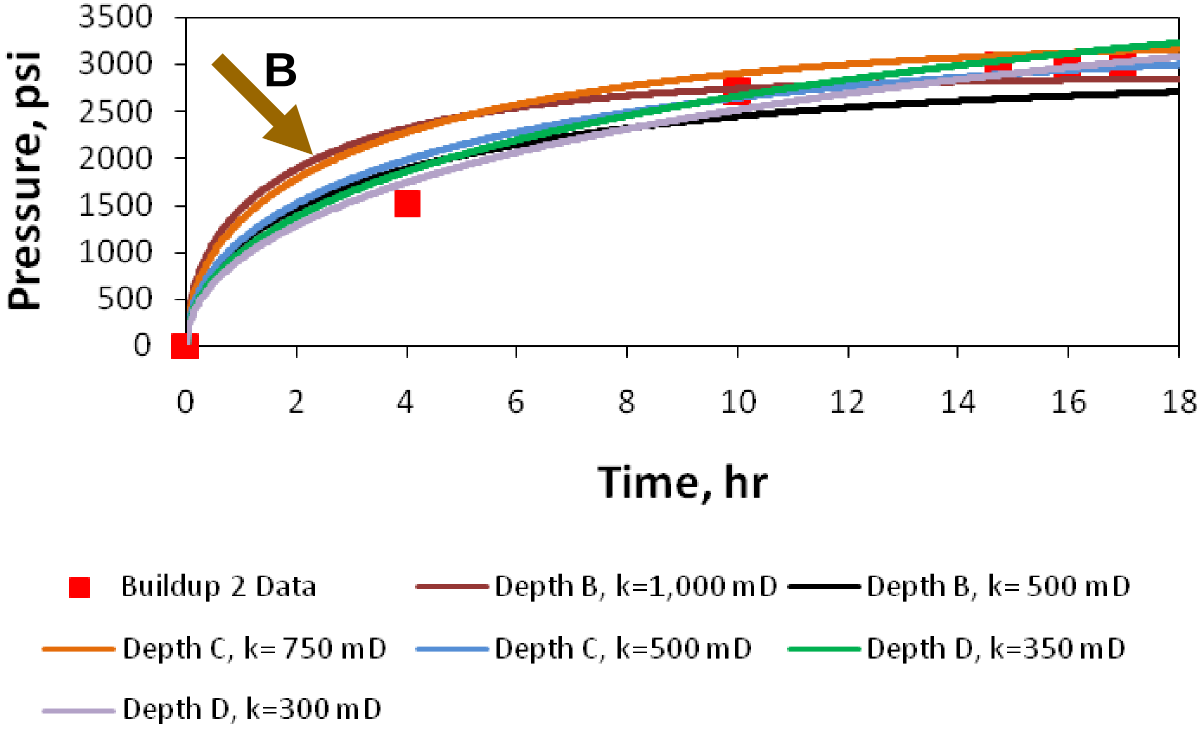
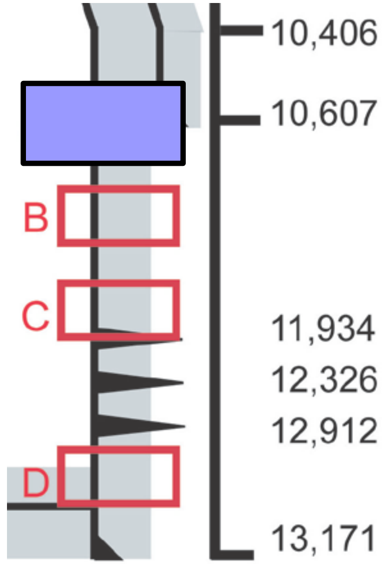
Leak at casing seat (depth A) eliminated



Leak depth B eliminated; fits at C and D have lower effective permeability





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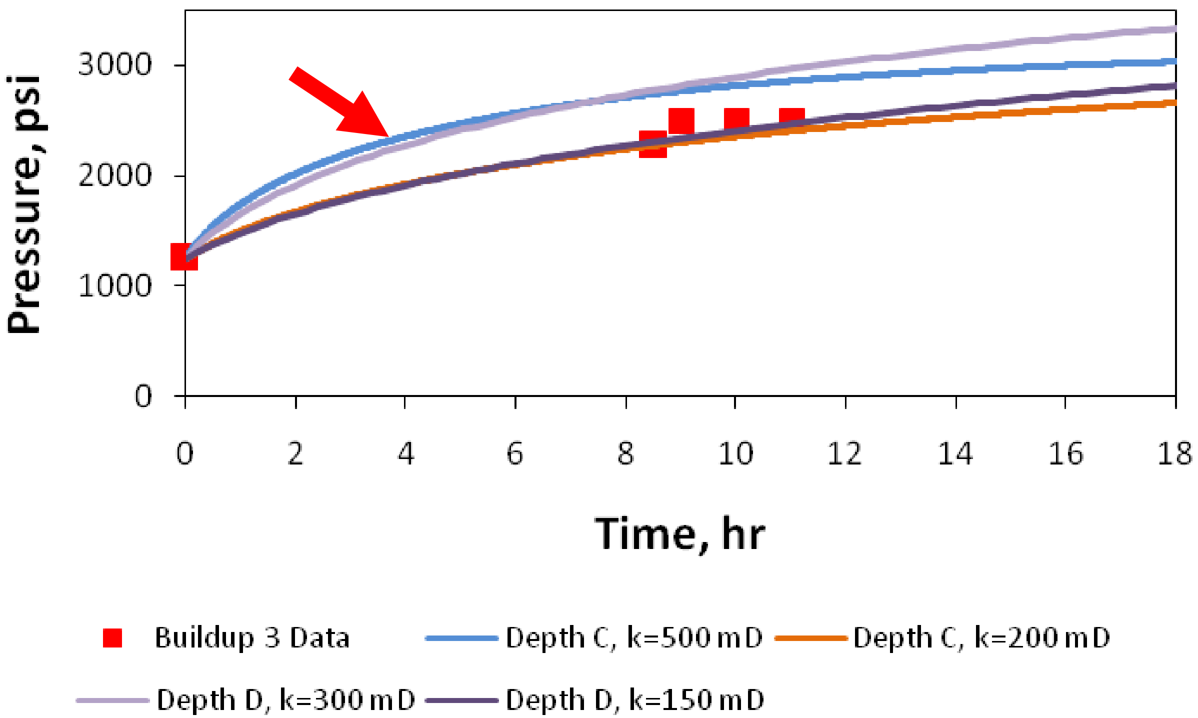
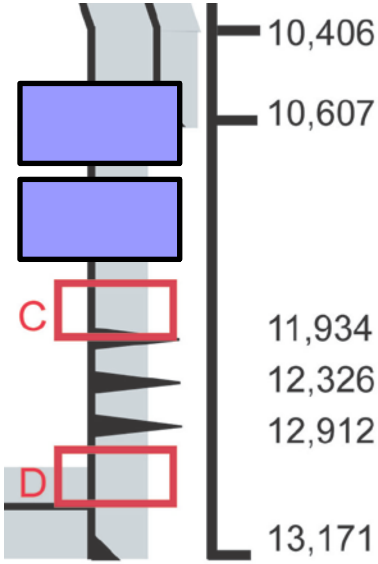
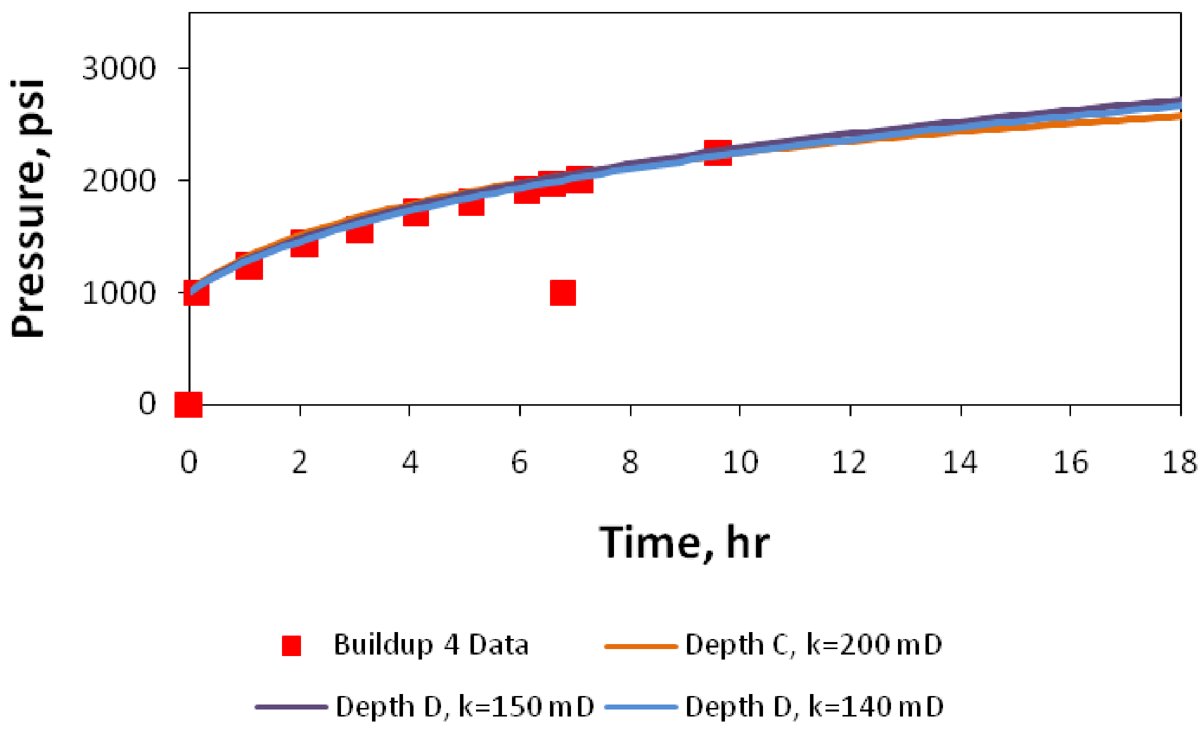
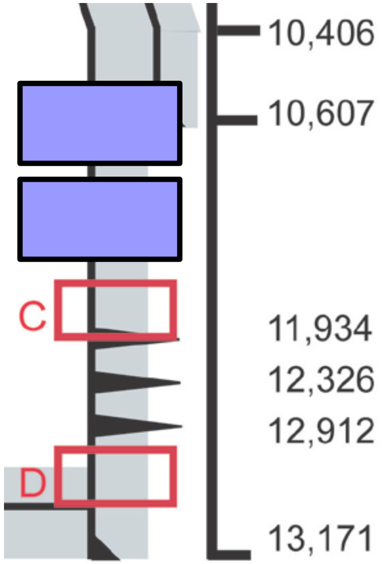
Lower permeability needed to fit both C and D depth



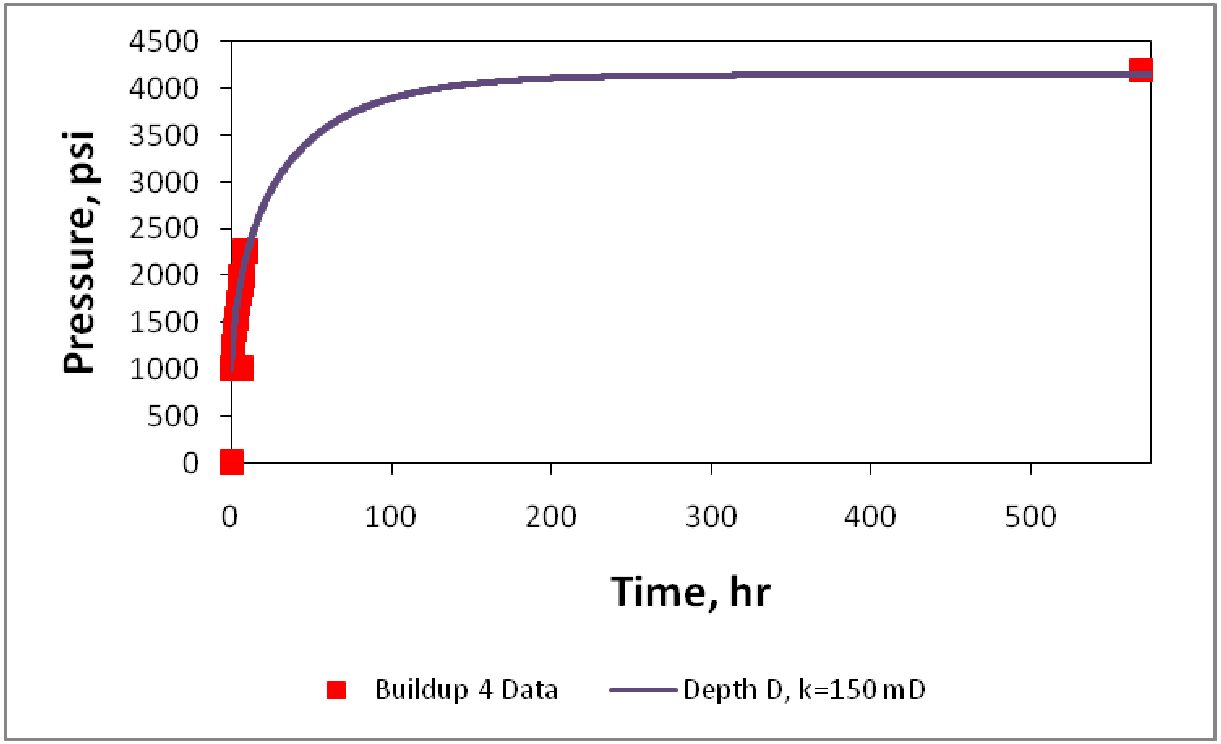


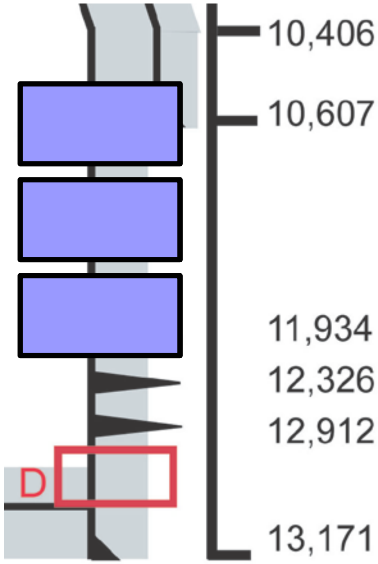
Effective permeability for 4th buildup also provides match for 3rd buildup





Using a pressure value recorded much later we can rule out depth C





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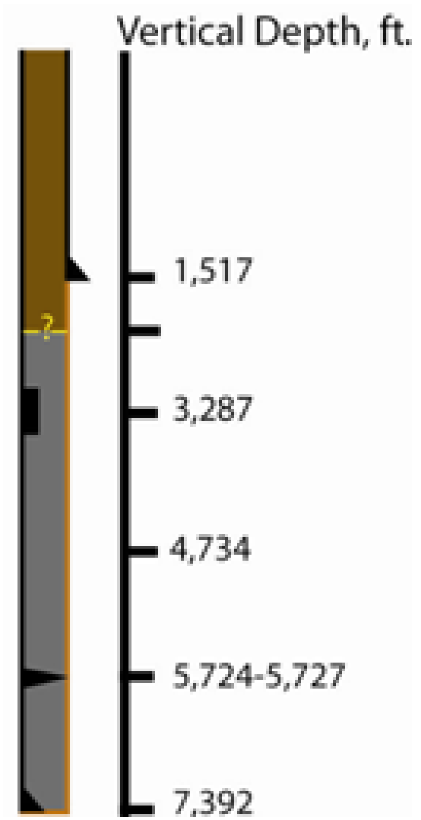
Case study 2

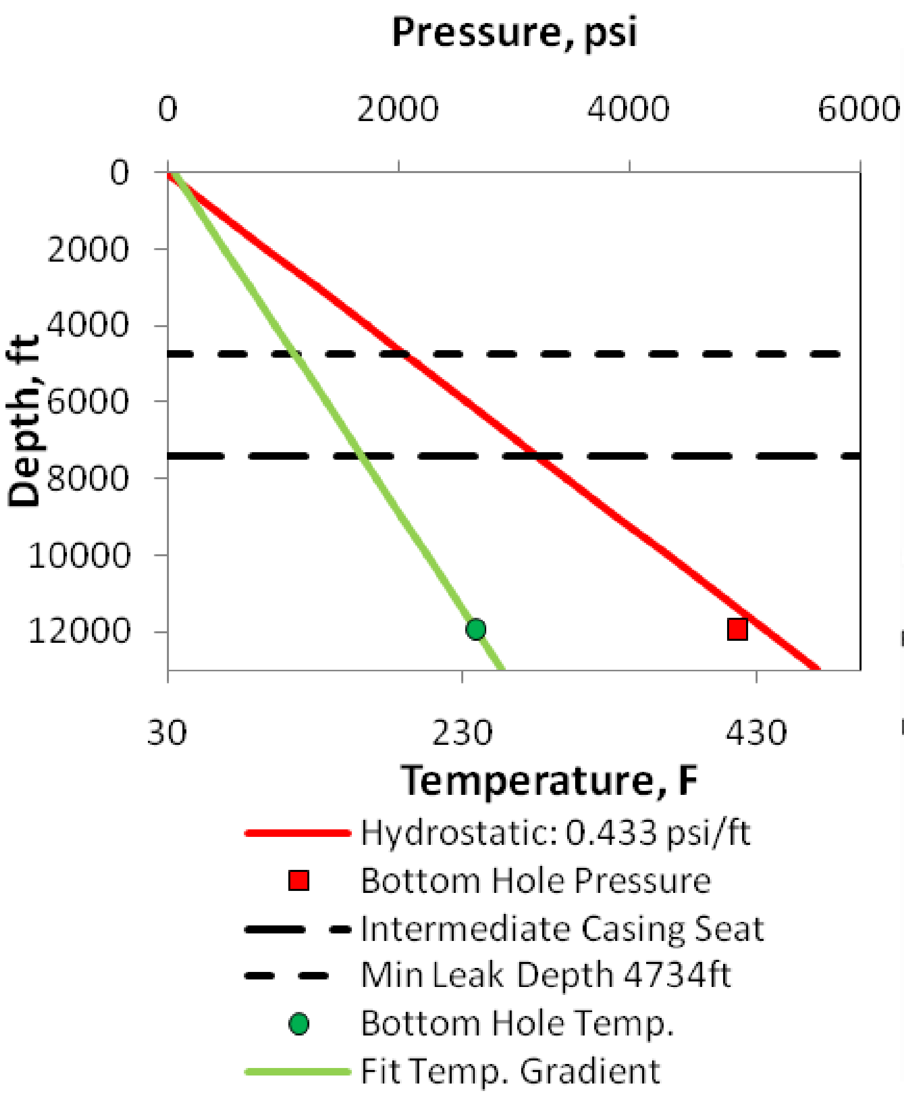
Onshore gas well from Alberta, Canada

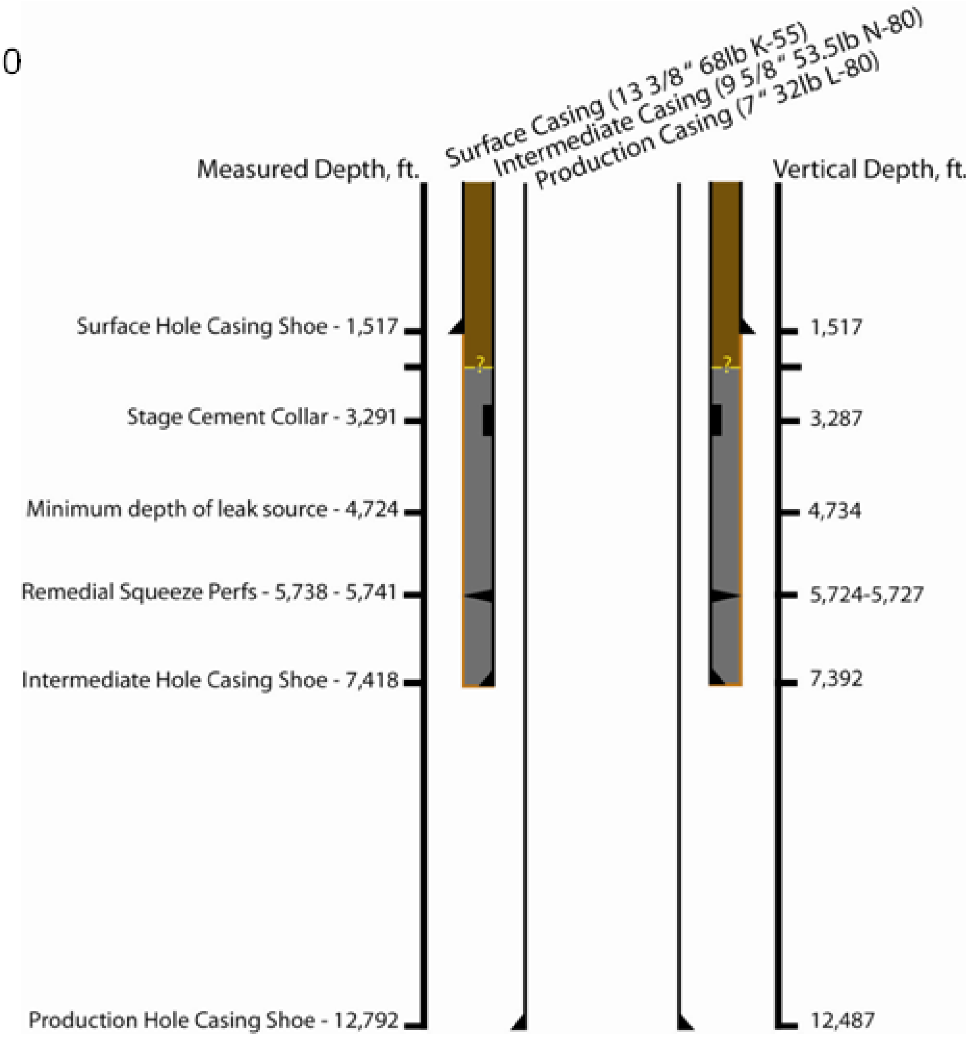
- Unsuccessful two stage cement job on intermediate annulus
- Unknown cement top
  - Precludes leak depth determination
- Pressure on production, intermediate annuli
  - Source and path for each annulus determined to be isolated based on gas chromatography and pressure buildup test
- Fairly good data quantity and fidelity

- **Objective:** Use pressure buildup data, long-term stabilized pressure to estimate effective permeability



Key well parameters used in SCP model





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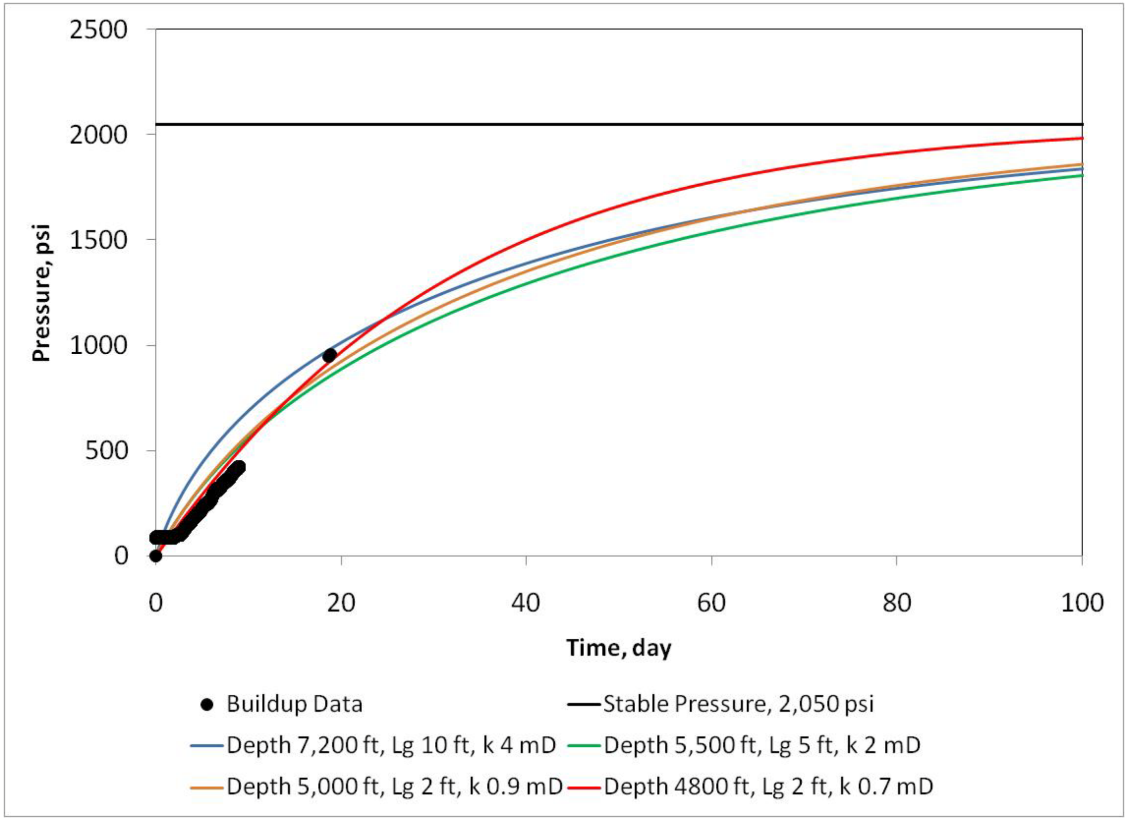
Effective permeability from fitting model for range of leak depths is 0.1mD to 5mD



- **Buildup data and stable pressure were fit using:**
  - o**Several leak depths**
  - o**Different initial gas length**

- **Results indicate:**
  - o**Shallow leak more likely (Depth 7,200ft is a poor fit to early behavior)**
  - o**0.1mD to 5mD much higher than value expected for intact cement**

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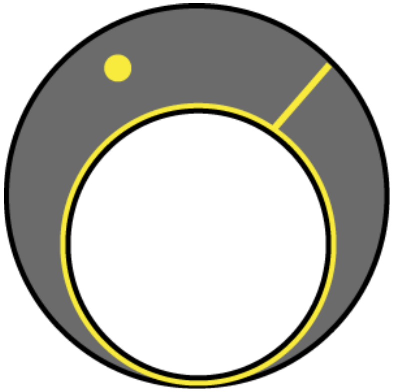
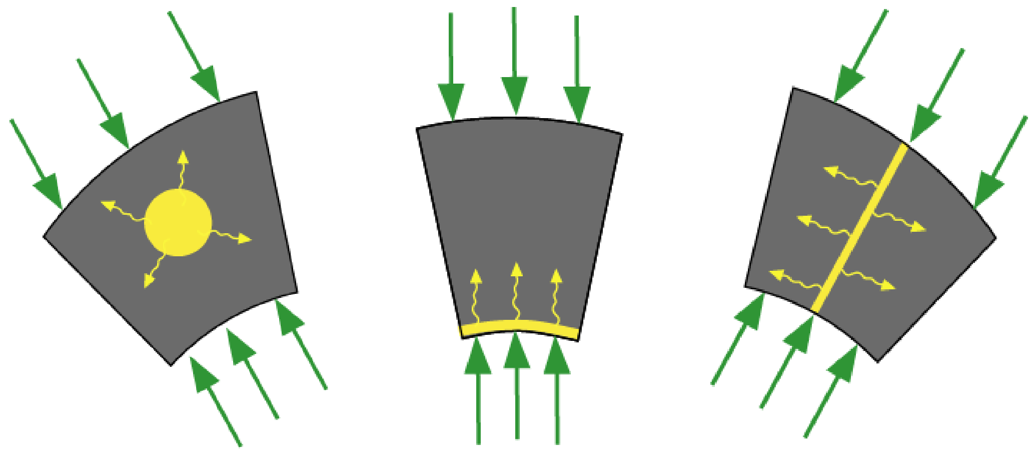
Geometry of leakage conduits within a well explains large effective permeability



Effect of pressure



Examples of poor cement jobs

Fig. 13—Conventional cement after cycling.

Heathman, 2006

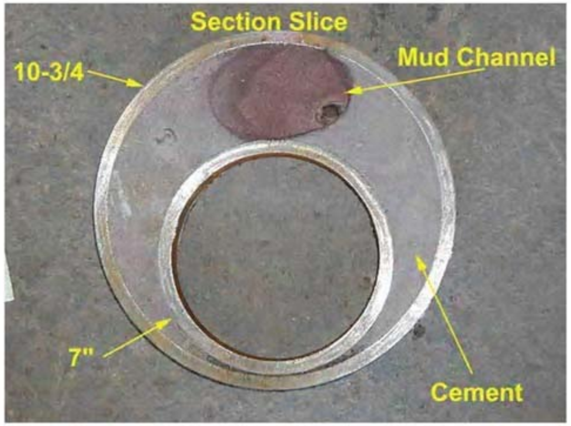


Figure 5-1: Concentric Casing Slice Illustrating Mud Channel

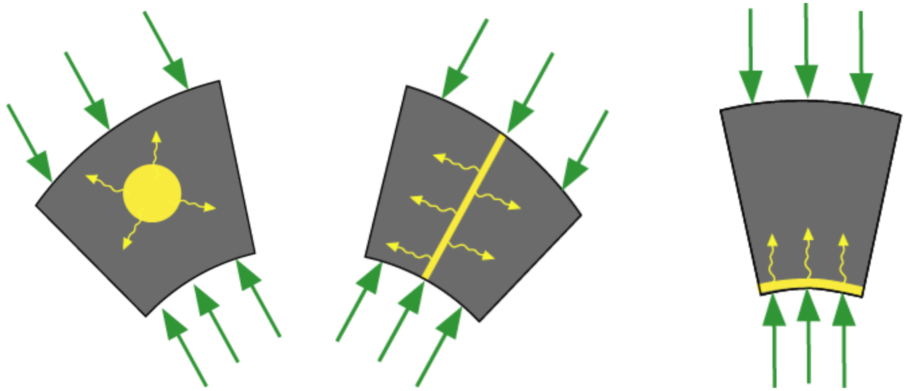
Figure 5-5: Close up of 7 and 10 ¾-in. Casing on the Rack

Soter Thesis, 2003

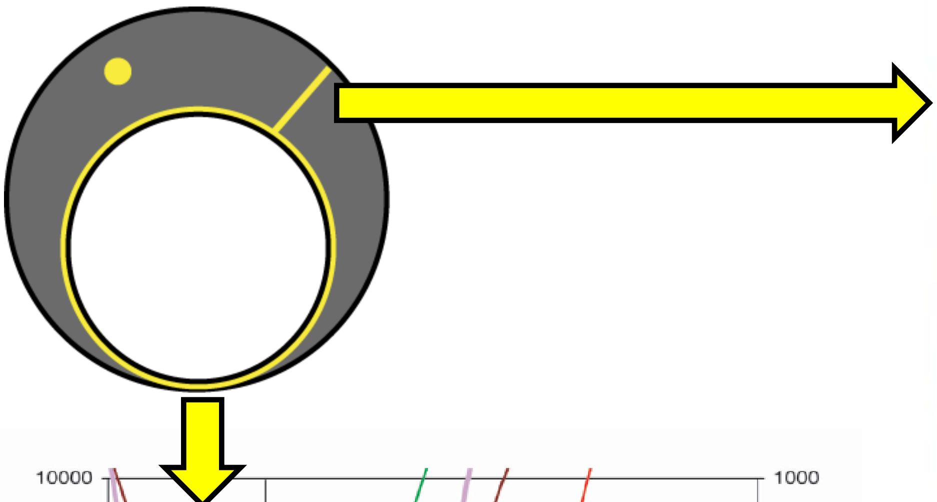
Interpret "cement permeability" as geometry of an equivalent conduit

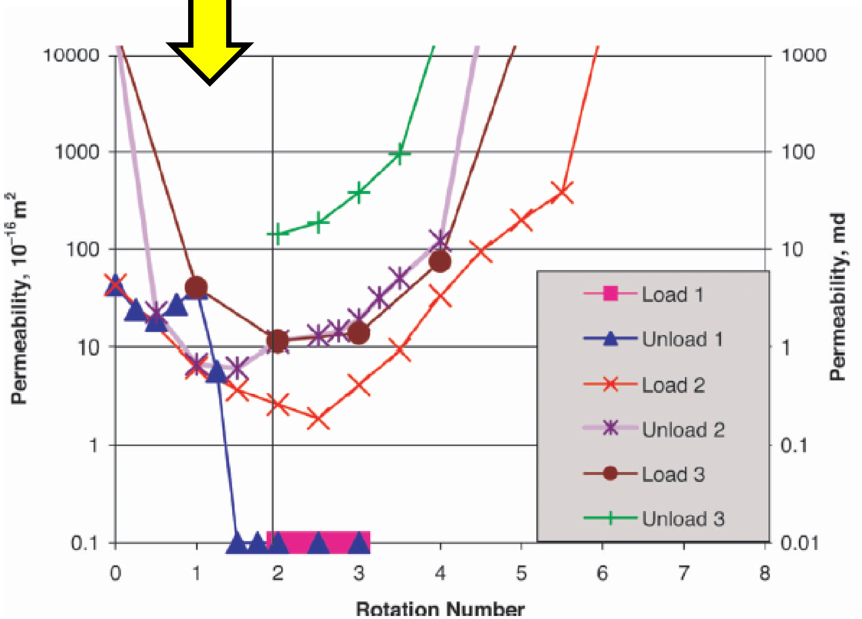
Parameters for leakage geometry from case studies and Xu 2002

Case Study	Effective Permeability, mD	Channel Radius, µm	Micro Fracture Aperture, µm	Micro Annulus Gap, µm
Case 1	140	238	92	23
Case 2	0.1 to 5	53 to 140	10 to 38	2 to 9
Well 23 (Xu, 2002)	0.403	71	15	4
Well 24 (Xu, 2002)	0.94	84	20	5



Conductivity of Cement After Loading Cycles





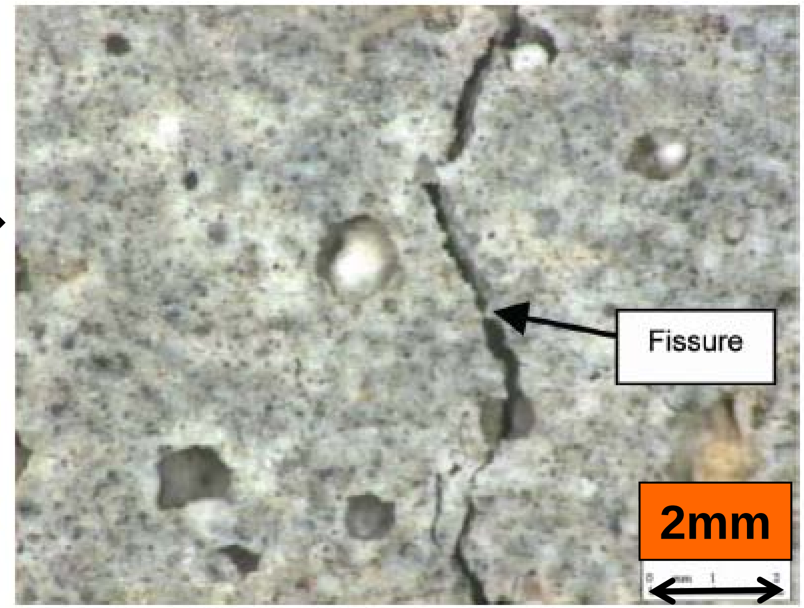


Fig. 10—Radial fissure observed on the surface of the foam in the cemented annulus after loading cycles (video microscope 175X).

Pressure cycling in lab experiment lead to tension failure and casing / cement debonding, which have effective permeability similar to what we see in our case study.

BOUKHELIEFA, 2005

Conclusions

- SCP analog provide insights into CO_2 migration along a wellbore
- Modeling pressure buildup provides necessary parameters for modeling CO_2 leakage
  - Effective permeabilities for case studies presented today are around 140mD and 0.1 mD to 5 mD
- Case studies may enable correlation of leakage parameters to more easily obtained well information
  - Permeability of ~140mD for an early leak and 0.1mD to 10mD for a leak that develops later
- Understanding coupling between confining stress, geochemical alteration of pathway, and flux of CO_2 is ultimate goal

Future work

Dean Checkai and Qing Tao are continuing on with the SCP analysis and CO_2 well leakage modeling

- **Forensics tool for data**
  - **Scrutinize what we "know"**
  - **Characterize the importance of certain parameters**
- **Couple leakage parameters to higher order variables**
- **Expand model to account for reservoir behavior**
  - **Cross flow**
  - **Reservoir depletion**
- **Develop a wellbore leakage model for CO_2**

We would like to thank the sponsors of the UT PGE's Geological CO_2 Storage Joint Industry Project

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Correlating higher order parameters to leak probability and flux

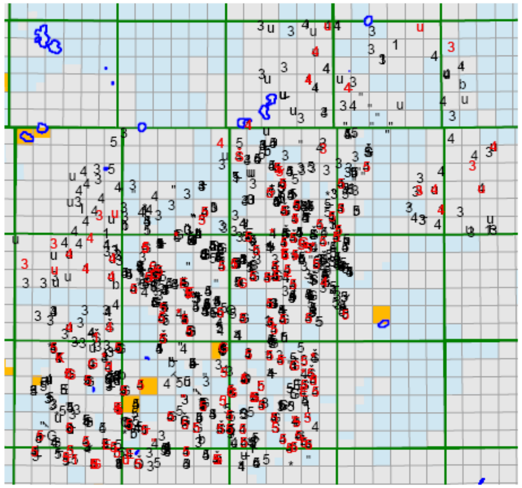
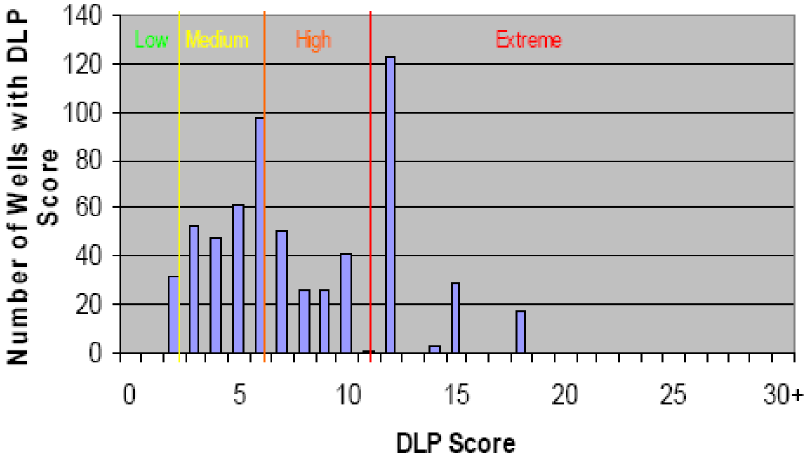
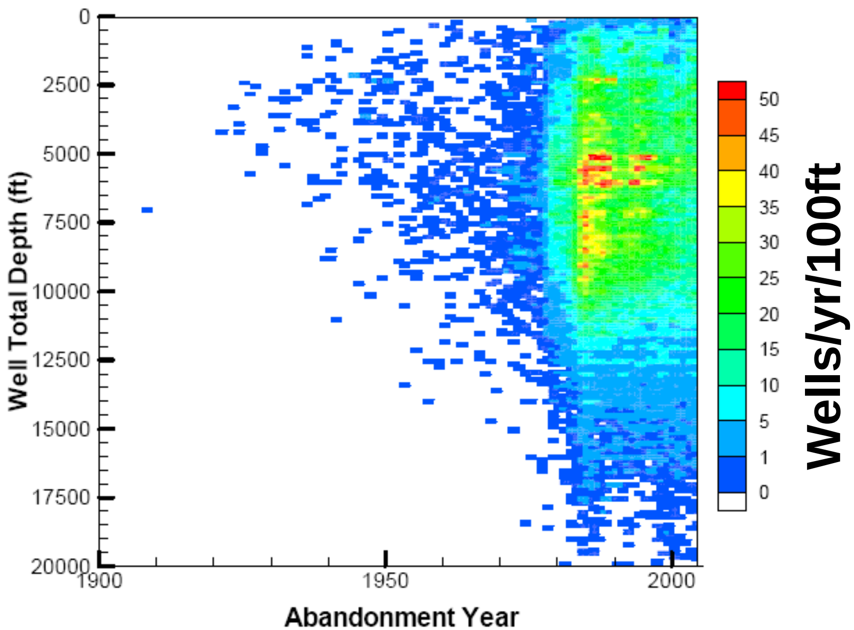


Figure 12: Zama Field DLP Score distribution.



Watson and Bachu, 2008



Nicot, et al., 2006

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GEOLOGICAL CO2 STORAGE

Cross flow in wells

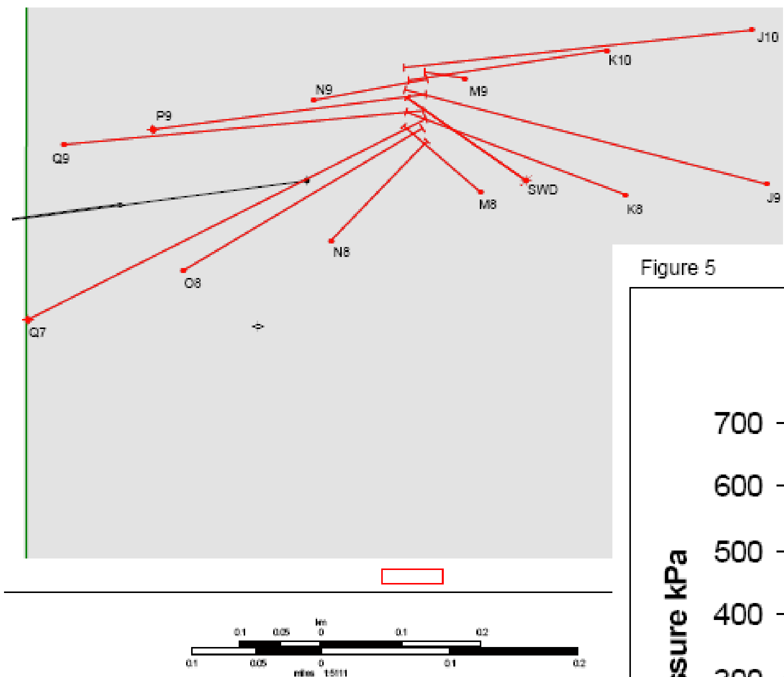
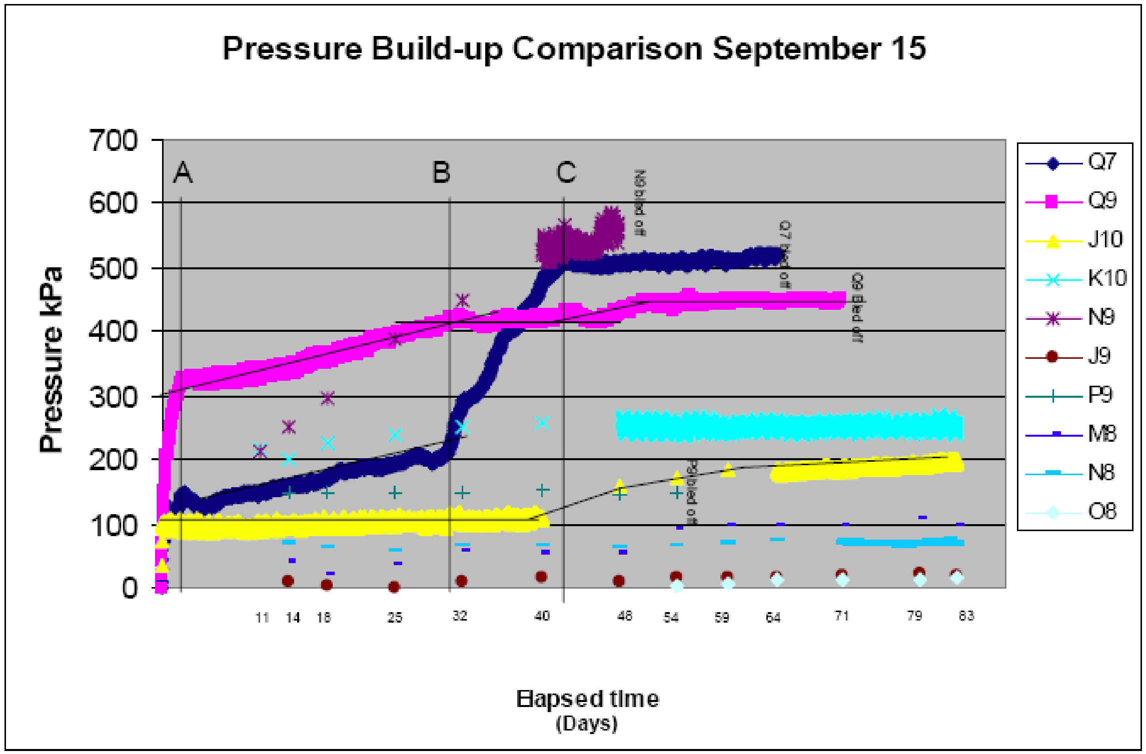


Figure 5



Identification and Qualification of Shale Annular Barriers Using Wireline Logs During Plug and Abandonment Operations - SPE/IADC 119321

SPE/IADC Drilling Conference and Exhibition, Amsterdam, The Netherlands, 17–19 March 2009.

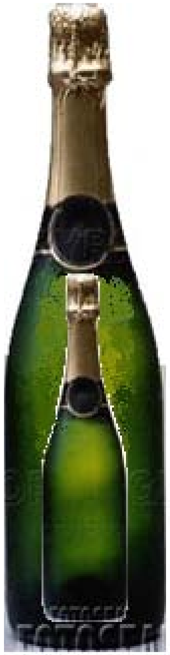
Stephen Williams,	Statoil ASA
Truls Carlsen,	Statoil ASA
Kevin Constable,	Statoil ASA
Arne Guldahl,	Schlumberger

Sidetrack activity on mature offshore fields

- Many offshore mature fields have a shortage of well slots
- Sidetrack activity needed to extend field life - increasing activity
- Typical sidetracks planned below 20” - 13 3/8” casing
- P&A of old well track requires suitable barriers to be put in place
- Barrier requirements on NCS controlled by Petroleum Safety Authority (PSA).
- Similar requirements on other offshore areas

PSA Barrier philosophy

- Norwegian PSA and StatoilHydro require tested double barrier approach
  - Follows NORSOK standard D-010

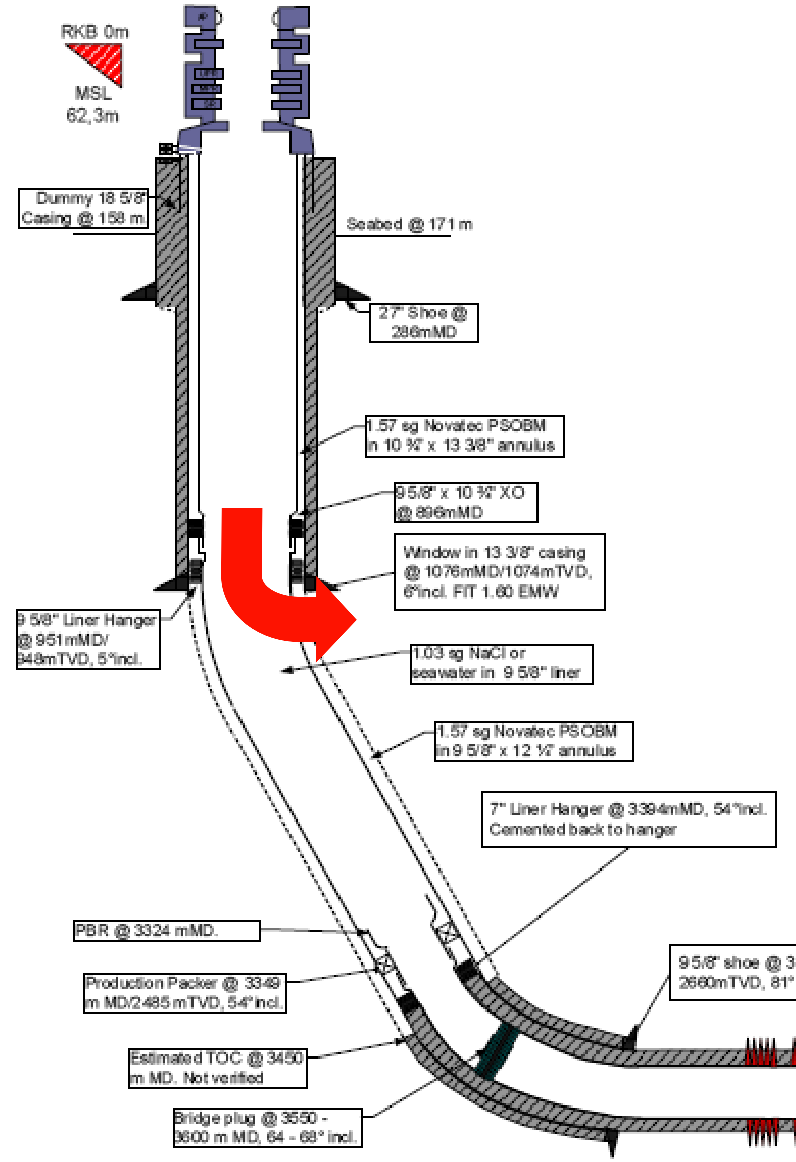


- Annular barriers are typically cement and wellhead
- During P&A an additional barrier is often needed

Secondary barrier problem during P&A

- Primary annular barrier usually good
- Secondary annular barrier often missing
- 50 m barrier often needs to be proven / added
- Solutions:
  - Perforate & pressure test suspected barrier
  - Perforate / squeeze / run bond log
  - Section mill casing
- All methods
  - Destructive
  - Time consuming
  - Failure prone

- Shale observed swelling /collapsing into hole
- Can formation be used as a barrier instead ?



Using collapsed formation as a barrier – PSA requirements

<u>NORSOK Standard D-010</u>

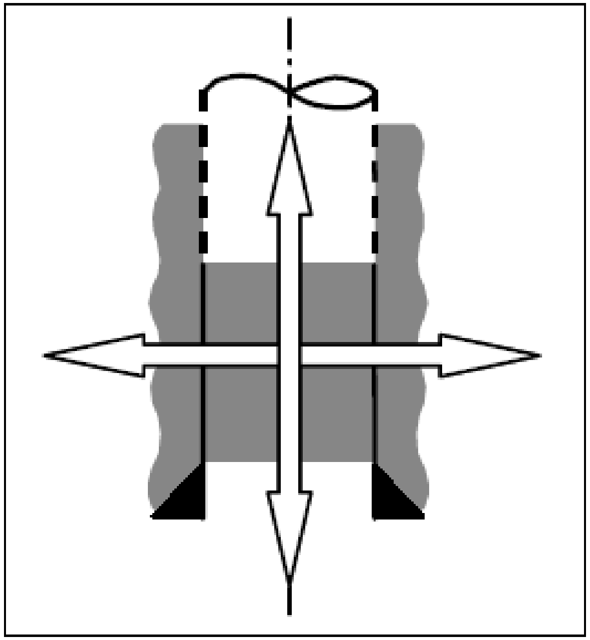
9 Sidetracks, suspension and abandonment

9.3 Well barrier acceptance criteria

9.3.8 Permanent abandonment

9.3.8.2 Permanent well barriers

…….Permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally……



A permanent well barrier should have the following properties:

a) Impermeable.

b) Long term integrity.

c) Non shrinking.

d) Ductile – (non brittle) – can withstand mechanical loads/impact.

e) Resistance to different chemicals/ substances.

f) Wetting, to ensure bonding to steel.

Shale satisfies all these criteria

Using collapsed formation as a barrier – Practical requirements

- We need to prove the collapsed formation is shale (impermeable, long term, non-shrinking, ductile, chemical resistance, wetting)

- We need to prove the formation has collapsed all around the casing over a sufficient interval (50m).

- We need a high enough formation strength to avoid propagating upward fracture propagation

Using collapsed formation as a barrier – Practical Solutions

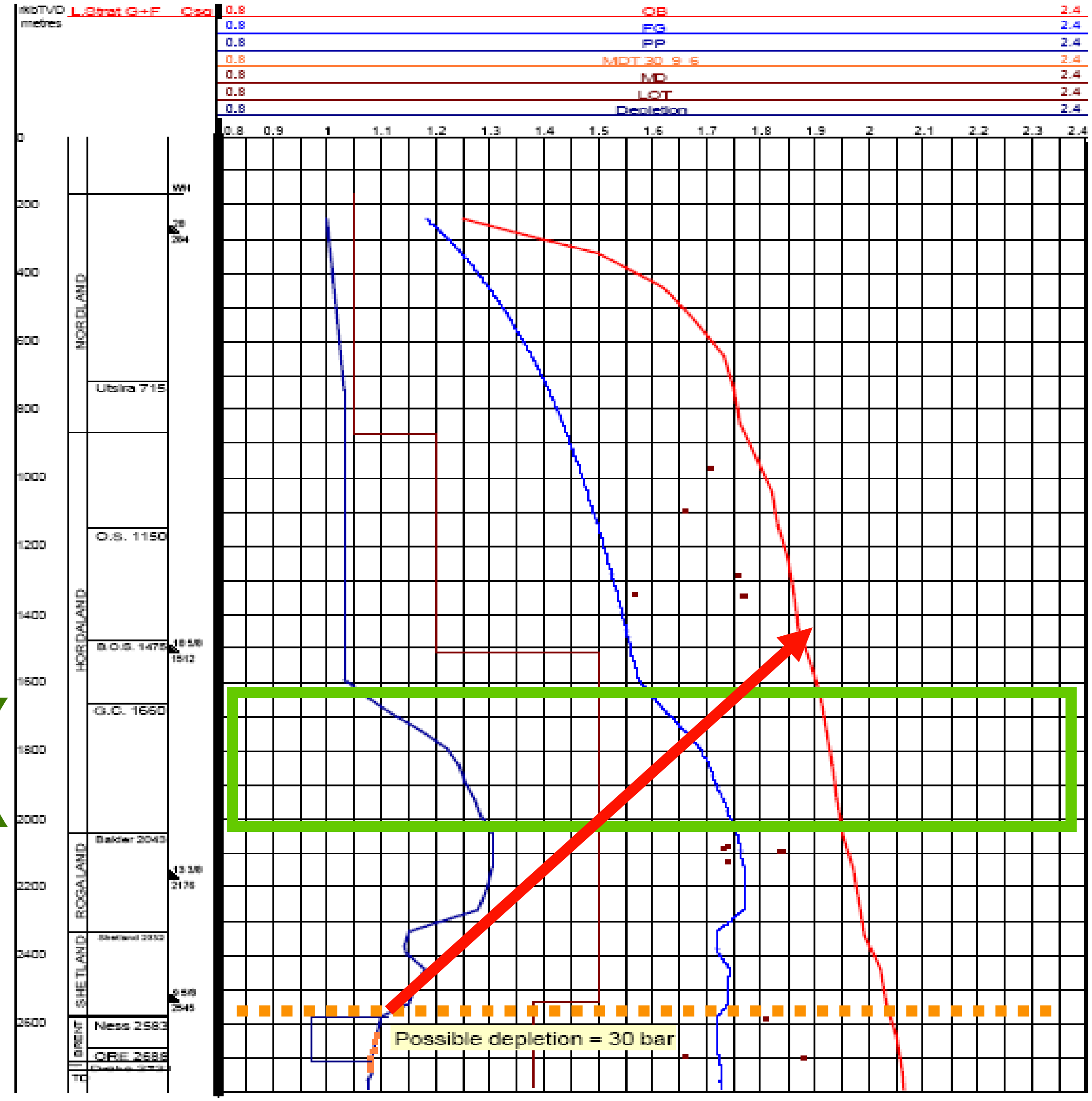
- We need to prove the collapsed formation is shale (impermeable, long term, non-shrinking, ductile, chemical resistance, wetting)
- Ensure geological data indicates good shale presence
- We need to prove the formation has collapsed all around the casing over a sufficient interval (50m).
- Run ultrasonic & CBL bond log
- We need a high enough formation strength to avoid propagating upward fracture propagation
- Need to know formation fracture pressure (leak-off).
- Must ensure this exceeds max theoretical reservoir pressure with a gas column to barrier

Also need to qualify that an identified barrier really is good

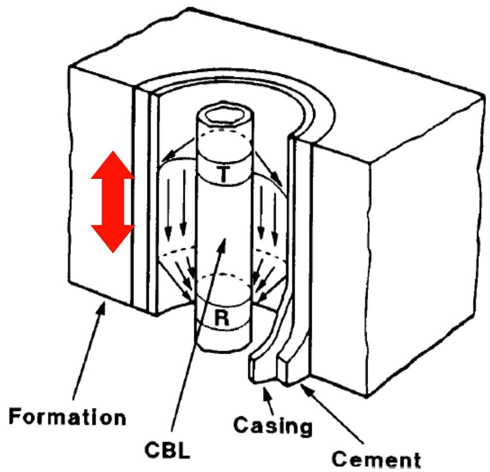
Ensuring sufficient fracture strength

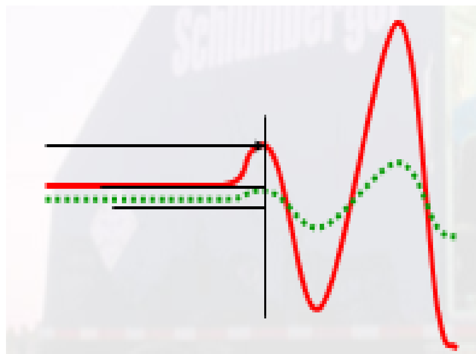
- Use pressure prognosis
- Ensure proven by leak-off test
- Exceeds fracture pressure at top green clay
- Sufficient thickness of clay below fracture pressure for barrier

Hordaland Green Clay



Bond logging - Basics of measurement



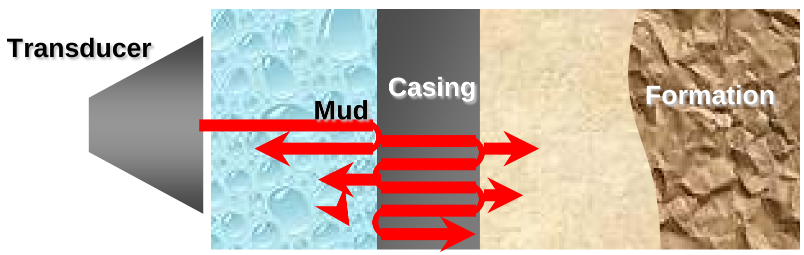


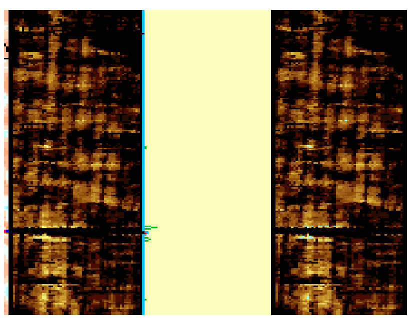
Measurement corresponds with the stiffness of the annular material

CBL free pipe > 50 mv

CBL good cement <10 mv

CBL shale barrier < 20 mv





Measures Acoustic impedance of annular material

Z fluid <2.5 MRayl,Z cement 4 – 7 MRayl, Z shale > 3 Mrayl

Formation collapse – mechanism

- Theory and drilling observations tells us:
    - Shale can deform and move into the borehole
    - Such deformation can be rapid or slow

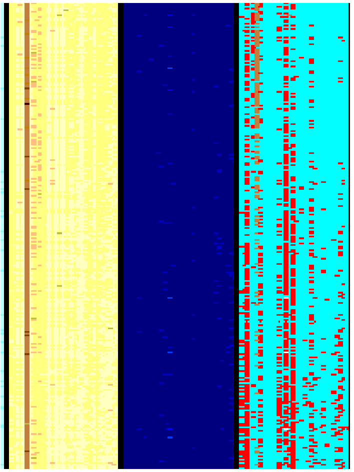
- The processes involved are:
    - Shear or tensile failure
    - Compaction failure
    - Thermal expansion
    - Chemical effects
    - Creep

- Important to understand collapse mechanism to ensure barrier is good
- Tests & Evidence shows collapse observed on bond logs is creep

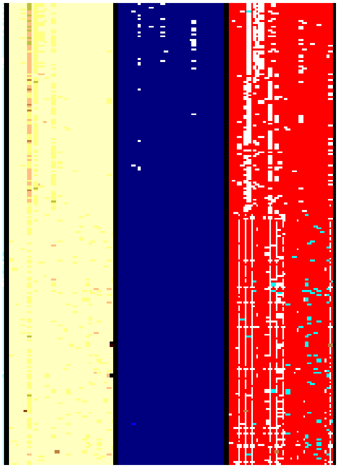
Collapse mechanism - test jig evidence

- Concern that loose material could look like a barrier on logs
- Test jig built to test logging tools with different materials in annulus
  - Loose non-consolidated material (sand)
  - Water (control)
- Results in sand showed poor bonding (bubbles in pore spaces)
  - Rules out mechanisms creating loose annular material (shear/tensile failure and compaction)

USI water annulus

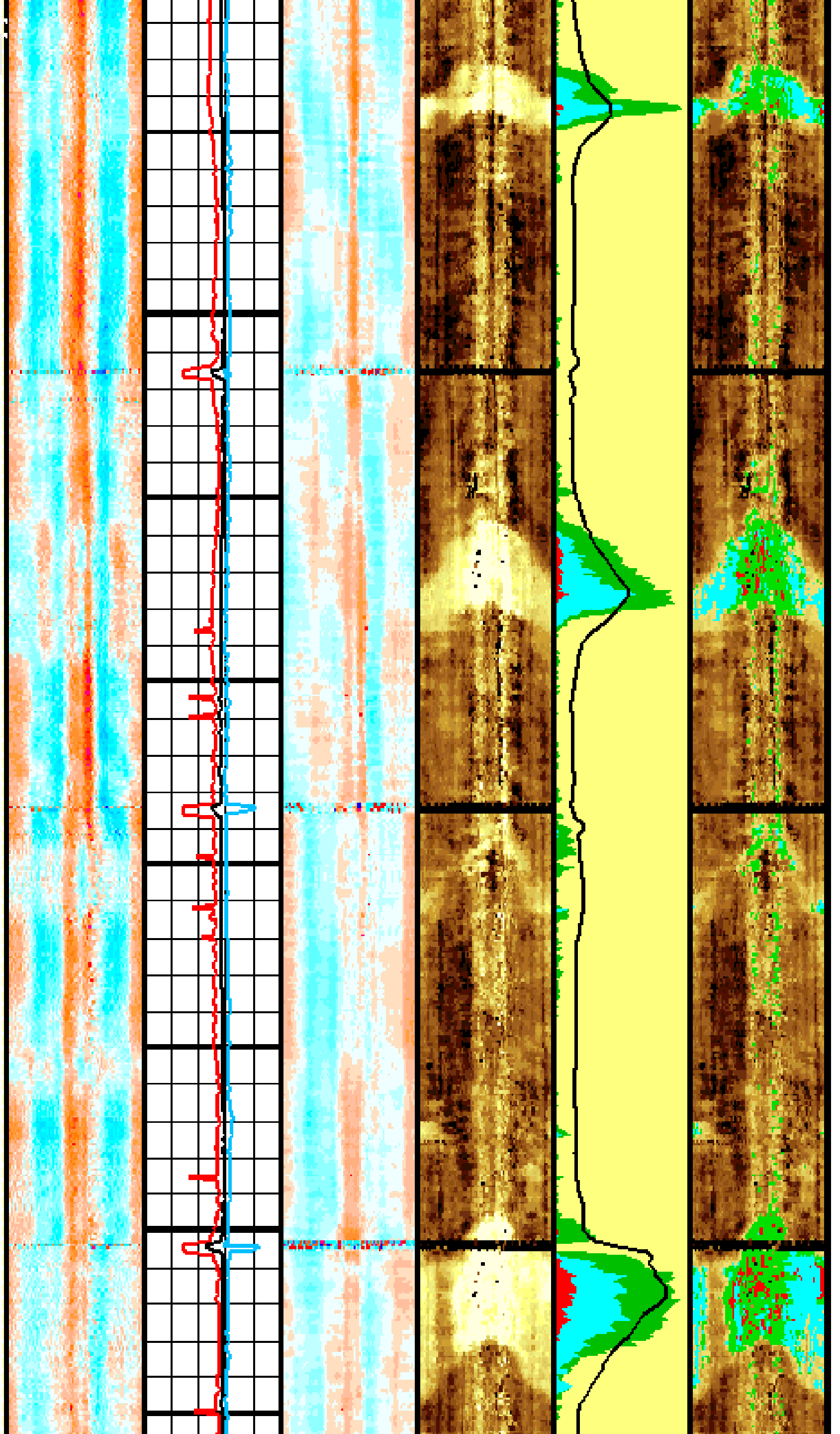


USI sand annulus



Collapse mechanism – log evidence

- Bond logs over shale zone with chalk beds
- Non cemented zone
- Sinuousoidal features correlate with chalk
  - Indicates annular material is geological beds
- Barrier occurs only in the shale sections
  - No evidence of rubble filled annulus
  - No evidence of thermal expansion
- Similar effects in OBM and WBM wells
- **Creep is the primary mechanism**



Formation barrier qualification - first test case

•NORSOK regulations allowed use of formation as a barrier.

•Sidetrack planned below 18 5/8” casing shoe

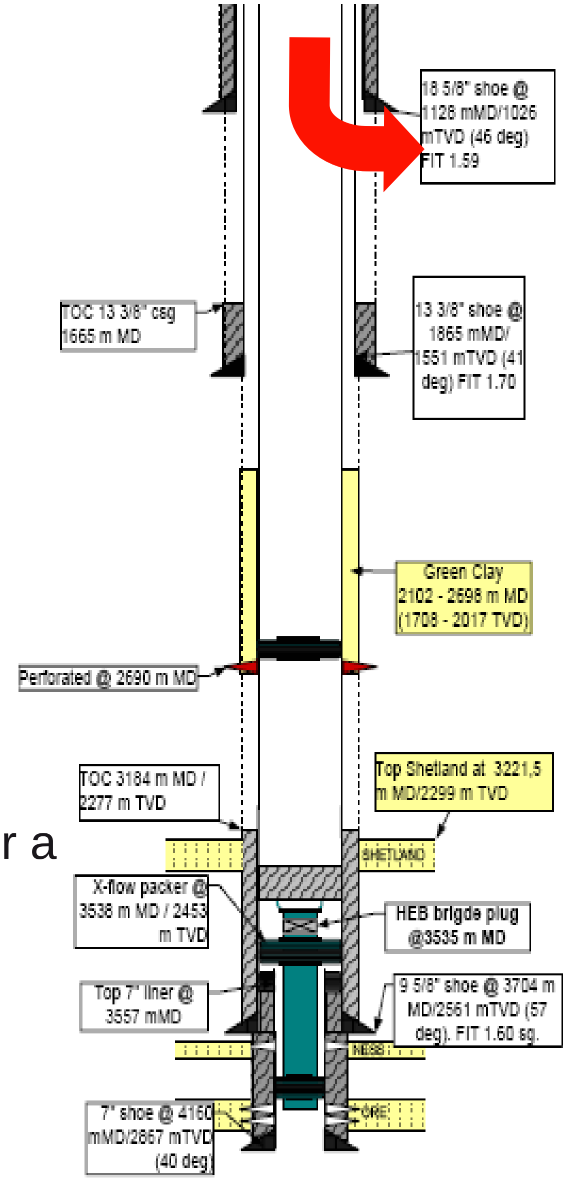
•Second annular barrier needed behind 9 5/8” casing

•Hordaland Green clay could provide required barrier

•Qualification process to be carried out by:
- •Recording bond logs and confirming good “bond”
- •Good pressure test through perforations up to leak-off
- •Monitoring surface annular response

•Annular barrier proven : P&A and sidetrack carried out

•Log used as a “calibration” for the response required for a shale annular barrier.



Test case #1

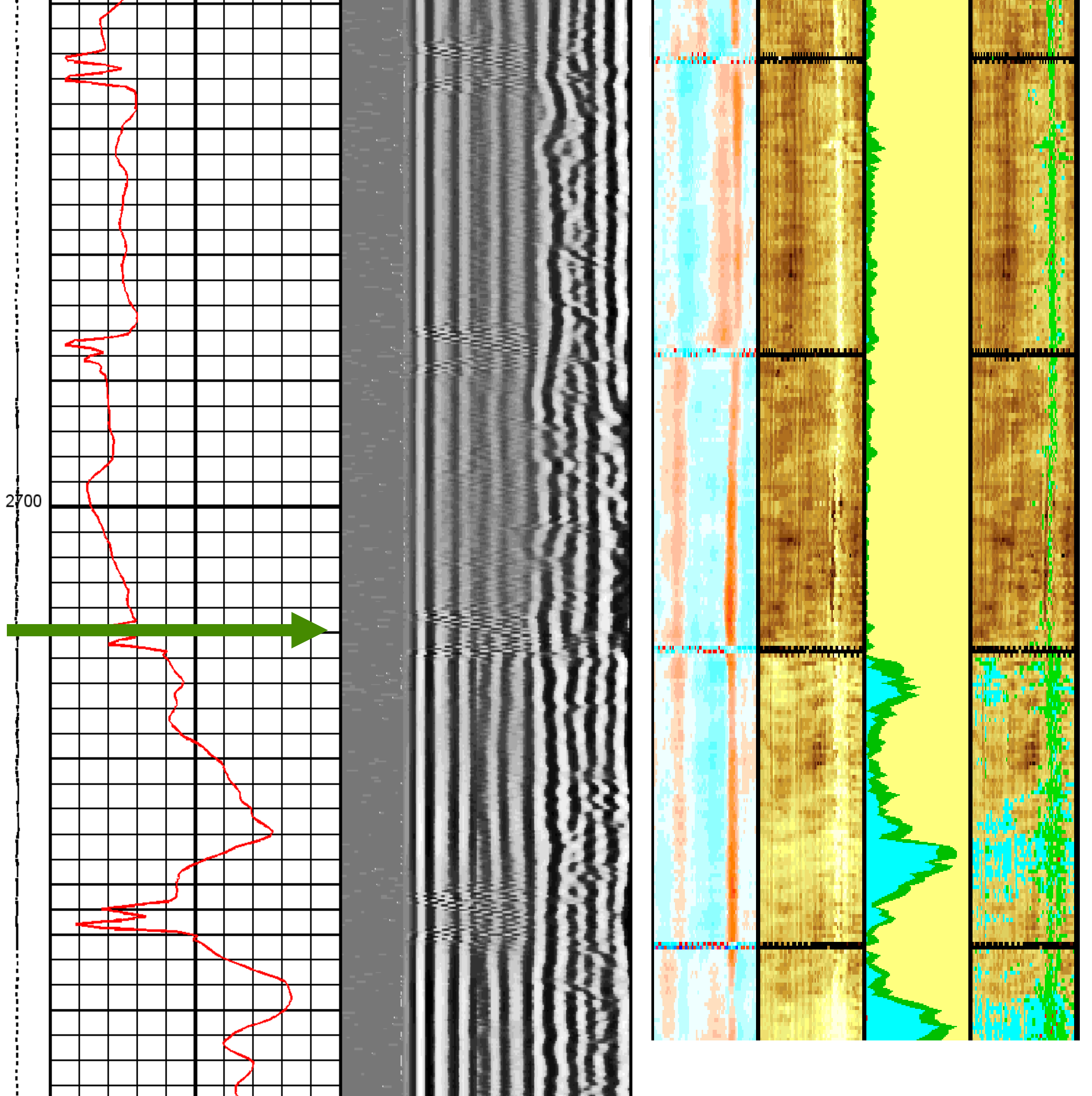
-Green clay at 2705m – 2100m

- Good barrier response at base green clay
    - Increased USI impedance,
    - Lower CBL
    - Low contrast VDL

- Good "bond" all the way up through the green clay

- Line at 270 degrees is due to casing wear groove

Base Green Clay



Test Case #2

•Good bond observed in shale zone required for barrier

•Pressure tested using wireline conveyed cased hole pressure testing tool and pump.

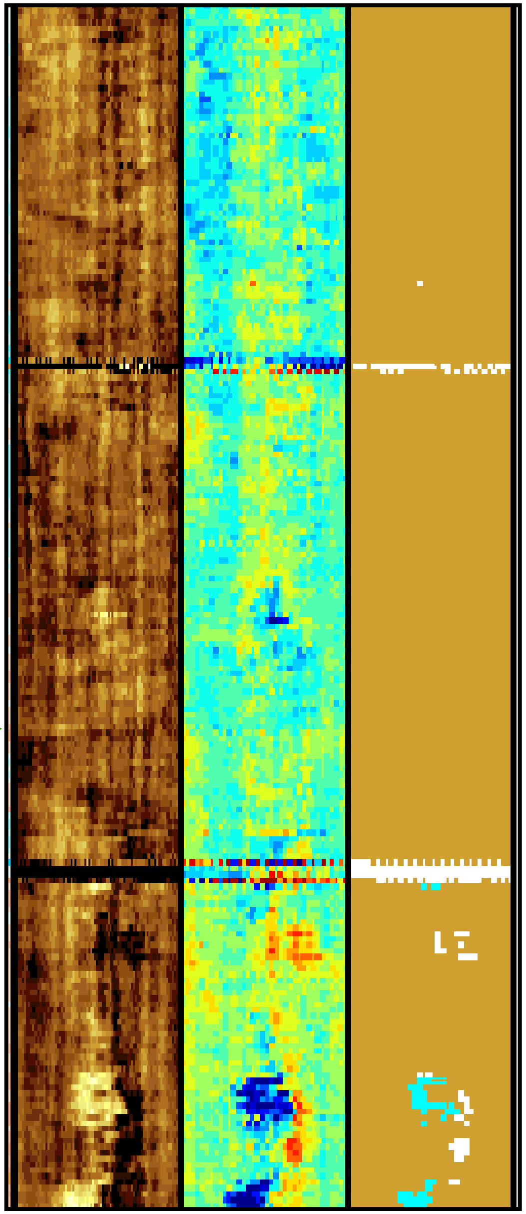
Set tool and seal off small area

Drill hole with flexible bit

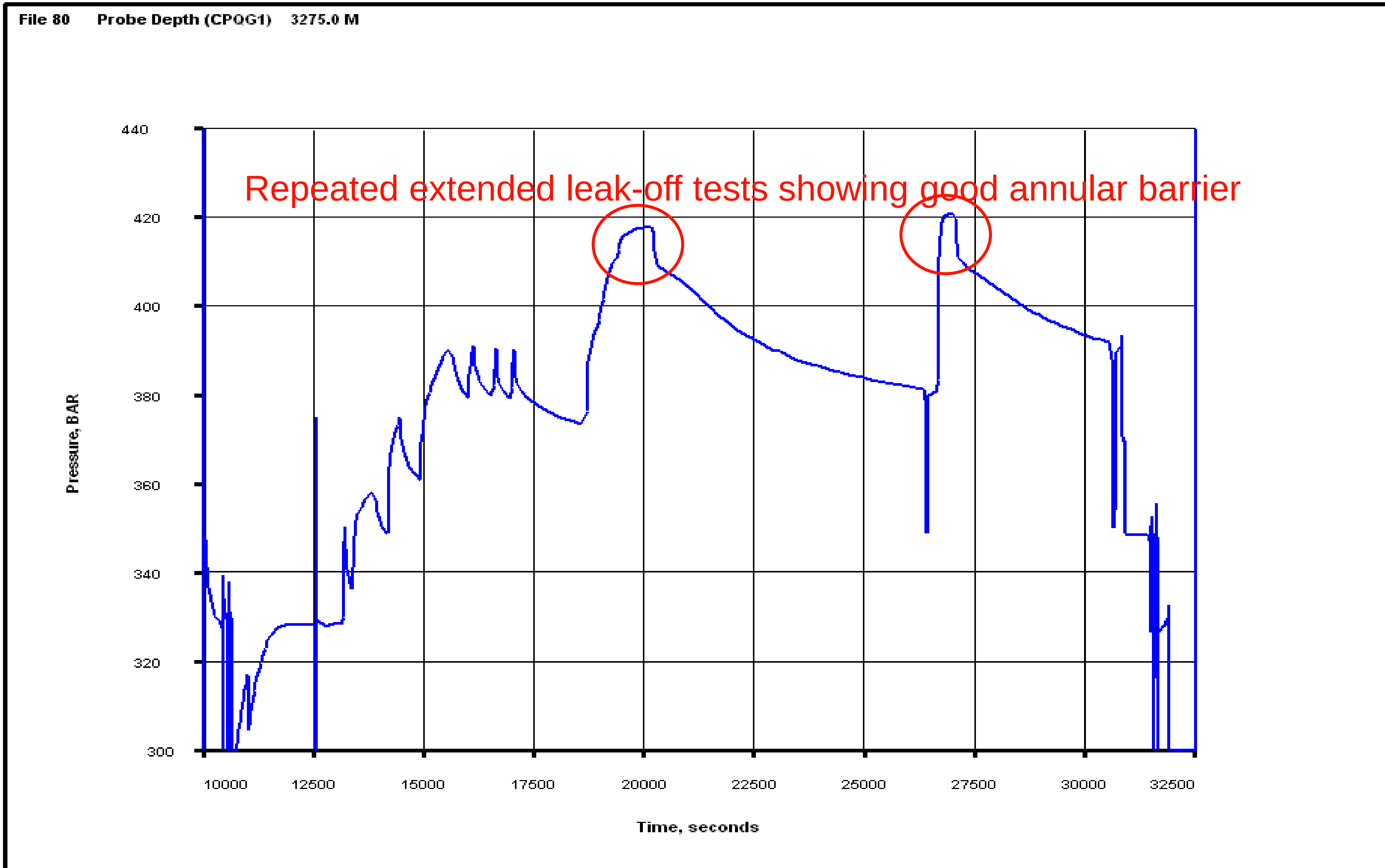
Pressure test through hole drill

Plug hole and retract tool

Pressure test made to leak-off at 3275m



Test case #2 – wireline leak off qualification @ 3275m



Governing documents update

- Operator’s governing documents updated to accept bond logs alone as a method to verify shale annular barriers
- Complies with NORSOK standard D-010 (Well integrity in drilling and well operations)
- Key governing document points:
- Position and extent of collapsed formation shall be identified through appropriate logs.
  - …two independent logging tools…
  - …Properly calibrated & suitable for applicable well conditions…
  - …interpreted by personnel with sufficient competence.
  - Both log measurements/tools show continuous good bonding over minimum 50 meter
  - Log cut offs defined in table below:

	Cement bond log amplitude	**Variable Density log**	**Ultrasonic acoustic impedance scanner**
Good Barrier	CBL less than 20 mV over 80% of interval	Low contrast casing signal and clear formation arrivals	AI reading greater than 3 MRayl on all azimuthal readings
No Barrier	CBL reading within 20% of free pipe reading	High contrast casing signal and weak formation arrivals	Reading less than 2 MRayl on some azimuthal readings

Summary

- Old annular barrier qualification procedures expensive and not practical
- Shale barriers proven by pressure testing & “calibrated” to logs
- New shale barrier verification procedure in line with NORSOK
- Governing docs and best practices updated
- Technique used on P&A operations since 2007 in over 50 wells
  - Annular barrier proven in most wells mainly in Tertiary and Cretaceous shales.
  - Approx 10% of wells have shown unacceptable shale barriers
  - Good barriers seen within 2 weeks after setting casing.

Conclusions

- Benefits
  - Multi-million dollar rig operating time savings
  - Reduced leakage risk due to non-destructive technique
  - Can prolong well life
  - Multiple HSE benefits
    - Improved well integrity , reduced operations and less material waste
- Mother nature’s barrier provides safest and most cost effective solution
  - Self-healing
  - More robust than man made barriers
  - Highly durable - will last for ever

Thank you for listening – any questions ?

Advanced Applications of Wireline Cased-Hole Formation Testers

Adriaan Gisolf, Vladislav Achourov,
Mario Ardila, Schlumberger

Schlumberger

Agenda

Introduction to Cased Hole Formation tester

Tool specifications

Applications

Zonal Isolation examples

- Cement Integrity
- Formation Integrity
- Annulus investigation

Conclusions

Cased Hole Dynamics Tester (CHDT)

Designed to drill

- through casing
- through cement
- into the formation

To measure

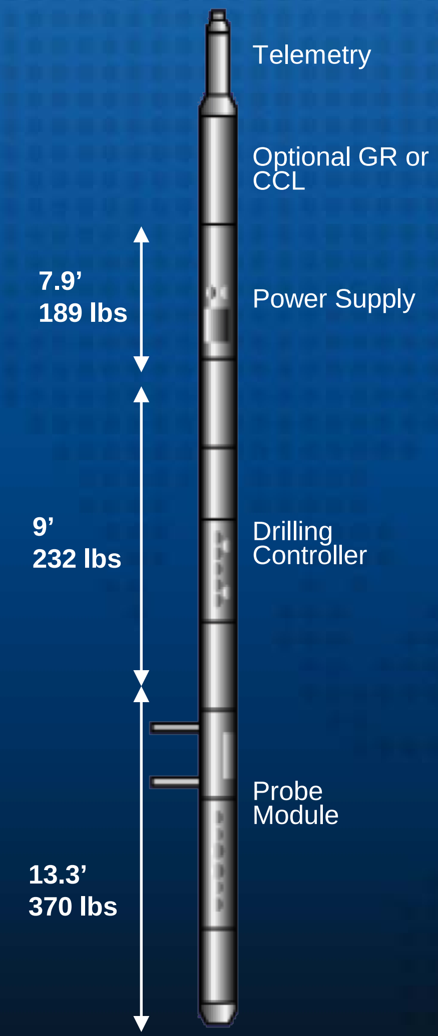
- reservoir pressure
- take fluid samples
- downhole fluid properties

And to plug the hole

- 10Kpsi bi-directional seal

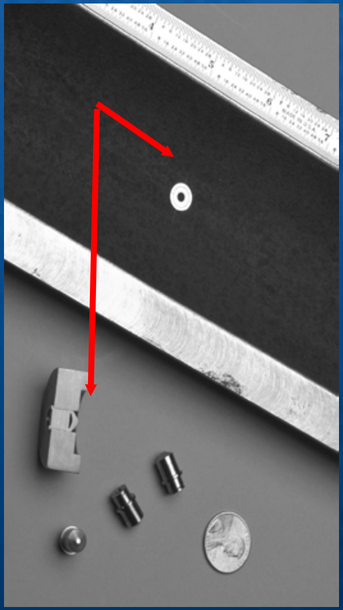
Specifications

- Casing 5 1/2” to 9-5/8” (tool OD = 4 1/4”).
- Up to 6 holes drilled & plugged
- Hole diameter = 0.28”, penetration = 6”
- Max. temp. 175 degC / pressure 1375 bar.
- Plug pressure rating = 700 bar bi-directional
- Overbalanced or underbalanced operation (275 bar)
- Pretest volume = 100cc (re- cyclable)
- Low-shock PVT sampling*
- Downhole realtime fluid properties*



Advanced design

Plug in Casing



- 375 bar bi-directional metal-metal seal
- Radial expansion of cup as pin is inserted

Revolver

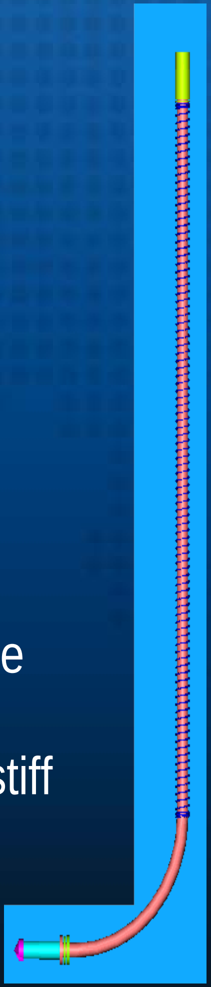
6 holes per run

Max. 2 modules*

Packer

Packers to cover casing range (5 1/2" to 9 5/8" OD)

Flexshaft



- Consists of several layers of spring wire wound around a central mandrel
- Highly flexible in bending - torsionally stiff
- Small diameter: 3/16"
- Tungsten carbide bit

Applications

Conventional applications

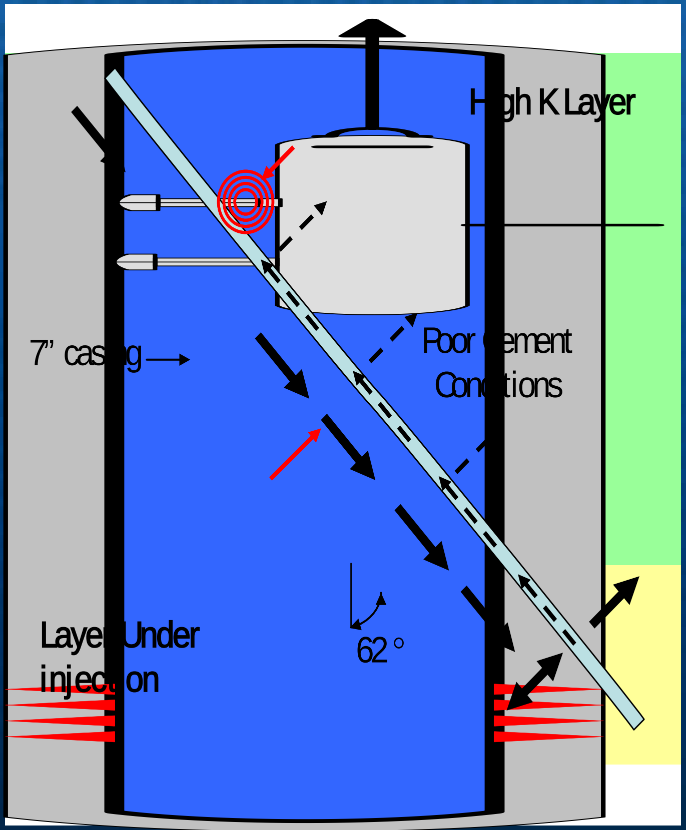
- Bypassed hydrocarbons
- Multi-Layer reservoir pressure monitoring
- New wells with difficult conditions

Advanced applications

- Zonal isolation studies
- Stress testing
- Annulus pressure investigation

Case 1 –Testing isolation between zones

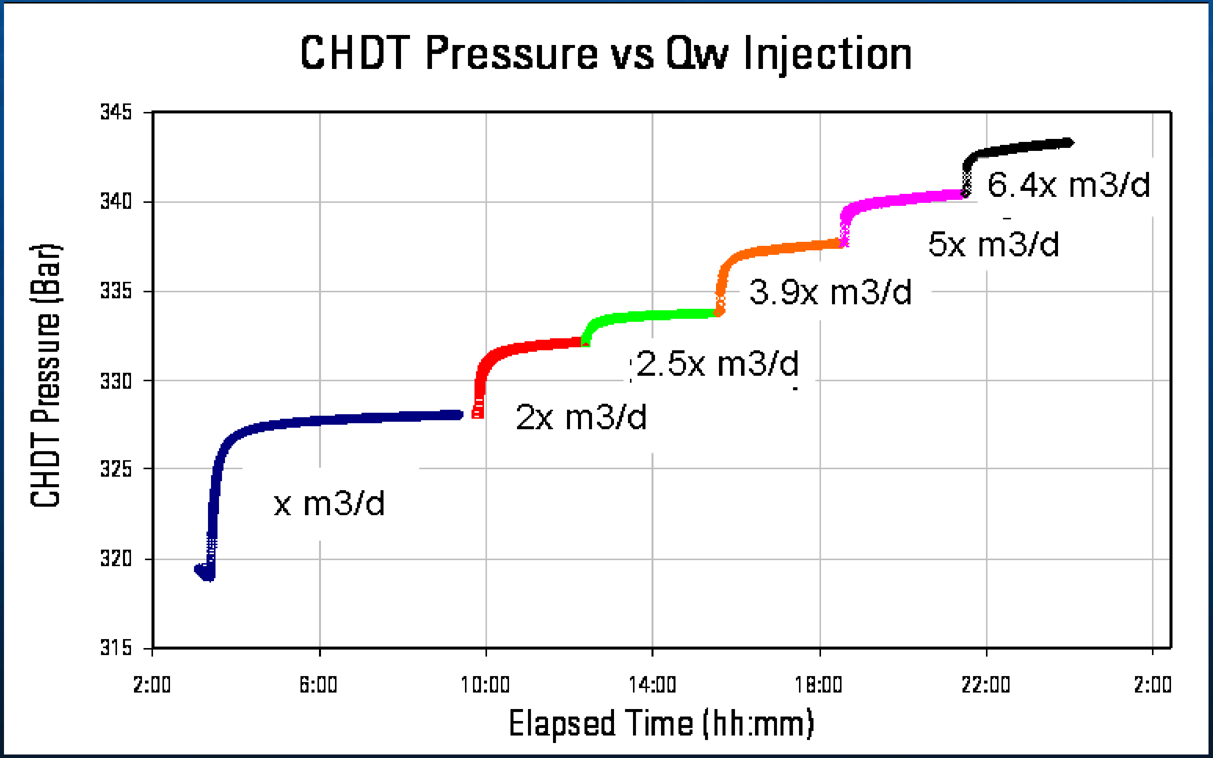
- Seawater injected to support production
- Tripling current injection rate will eliminate need for additional injection wells or workovers
- Poor cement coverage across injected formation and high permeability neighboring formation
- Several attempt to squeeze proppant and gel into the annulus unsuccessful
- Increase injection feared propagate and frac the cap rock



Tool conveyed with Tractor (62 deg)

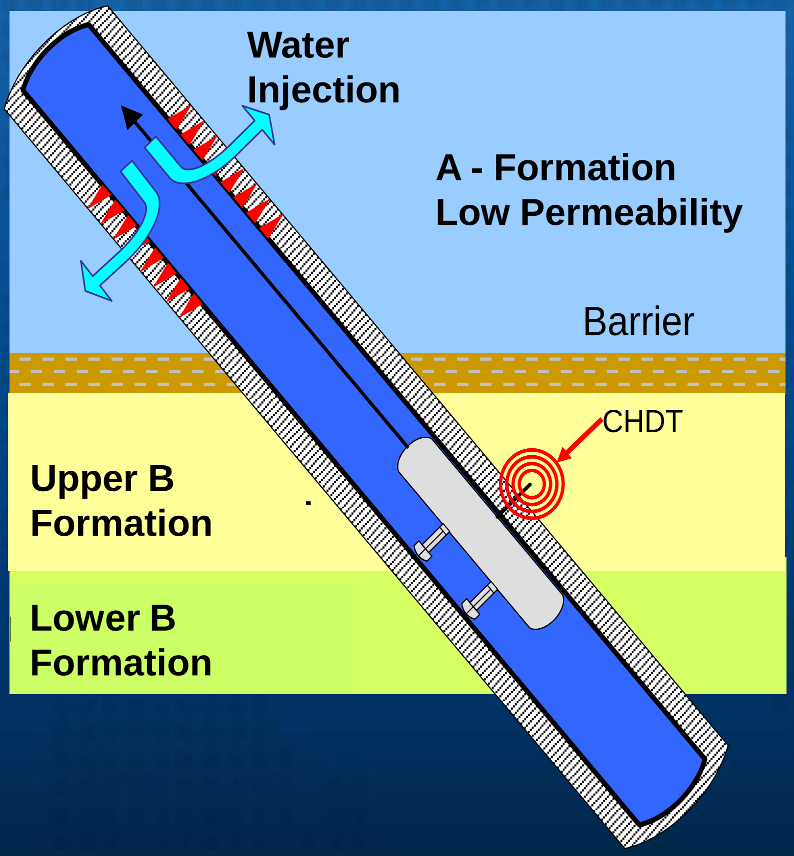
Results

- CHDT showed communication between formations
- Maximum safely achievable injection-rate was estimated
- Injection rate tripling not possible



Case 2 –Testing communication between zones

- Deviated reservoir section completed with 7 inch liner
- Injection through A - formation
- Unknown connectivity between B and overlying A formation
- B formation potentially pressurized
- Future drilling plans through the B formation planned with equipment of limited pressure rating
- Max. deviation 81 deg, 45 deg at B formation. Tool conveyed with tractor
- Good cement identified through ultrasonic log



Case 2 - Testing lower B formation

Objectives

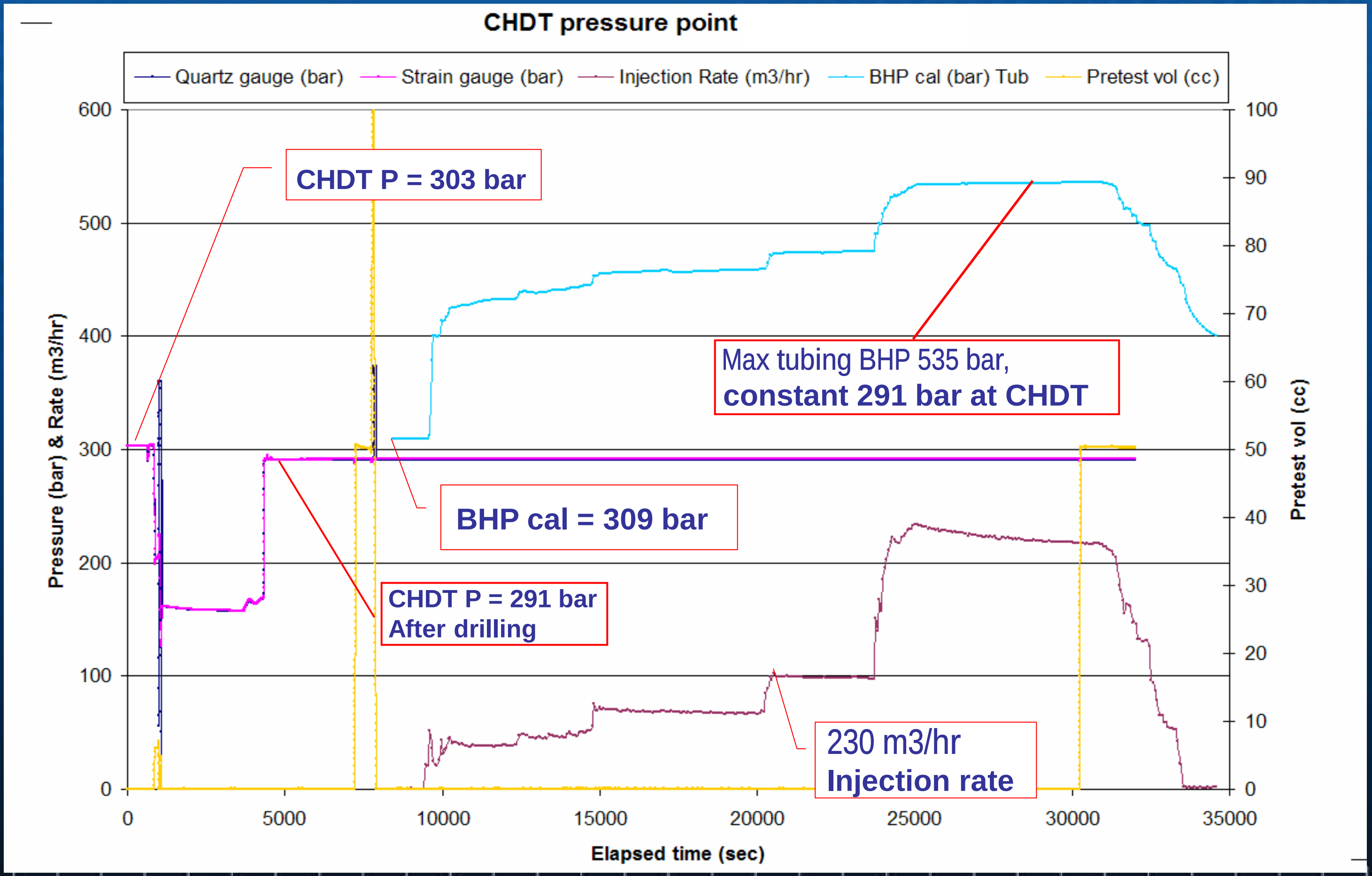
- Identify communication between reservoir under injection and lower intervals.
- Determine representative reservoir pressures

Lower B formation operational sequence

- A hole was drilled though the casing, cement and formation
- CHDT pressures monitored in real-time to allow injection sequences optimization
- Formation pressure observed after the drill bit penetrated casing, cement & formation
- Pretest taken to confirm the formation pressure of 291 bars
- Seawater injected at four different rates into the upper A formation
- Drilled hole was plugged and tested to 170 bar differential pressure

Case 2 - Testing lower B formation

No pressure response observed on the CHDT during injection, indicating that the lower B formation was not in communication with the A formation



Case 2 - Testing upper B formation

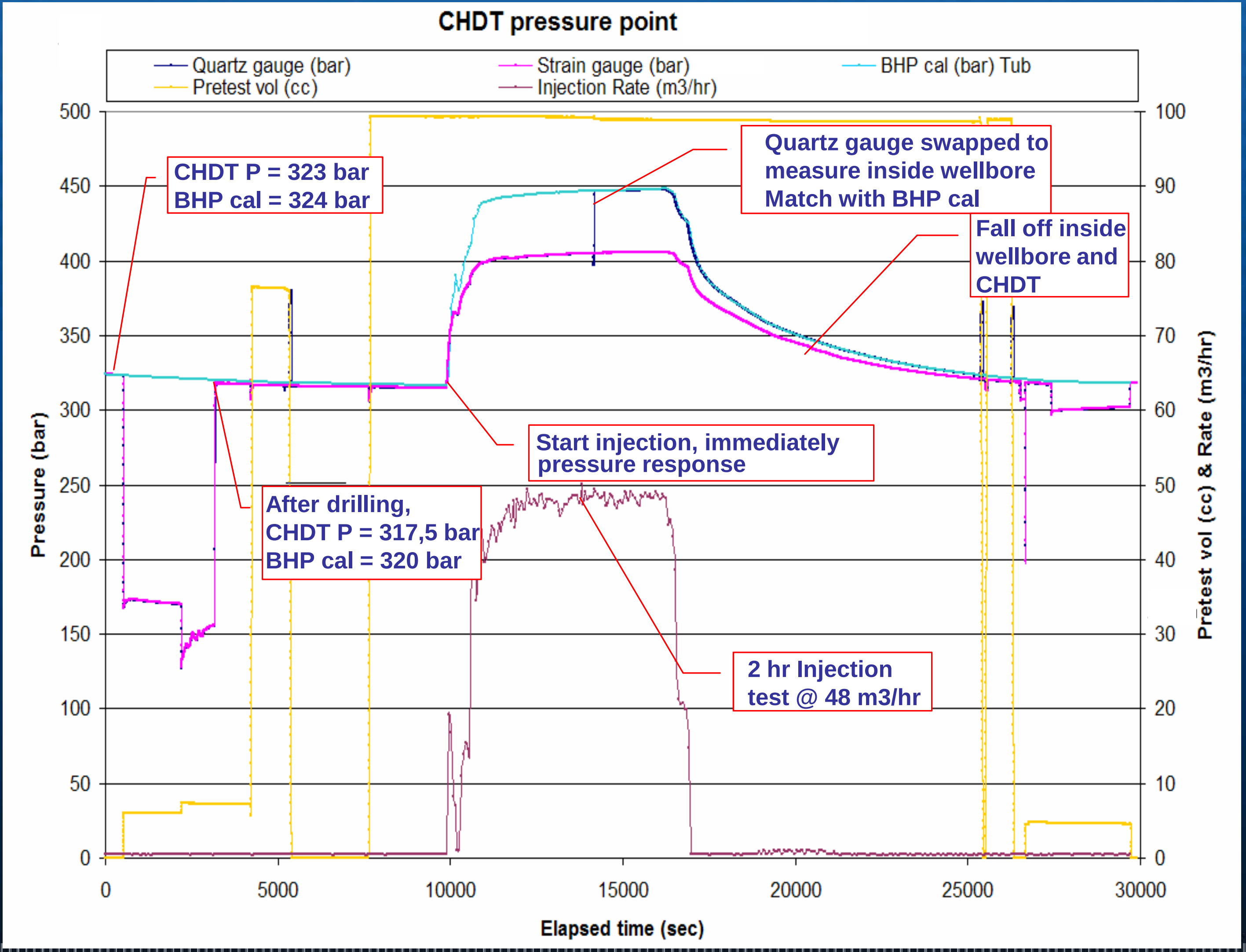
Upper B formation operational sequence

- After drilling casing, cement and formation the pressure stabilized quickly at 317.5 bars, then slowly decreased
- The same pressure fall-off was observed on the surface gauge

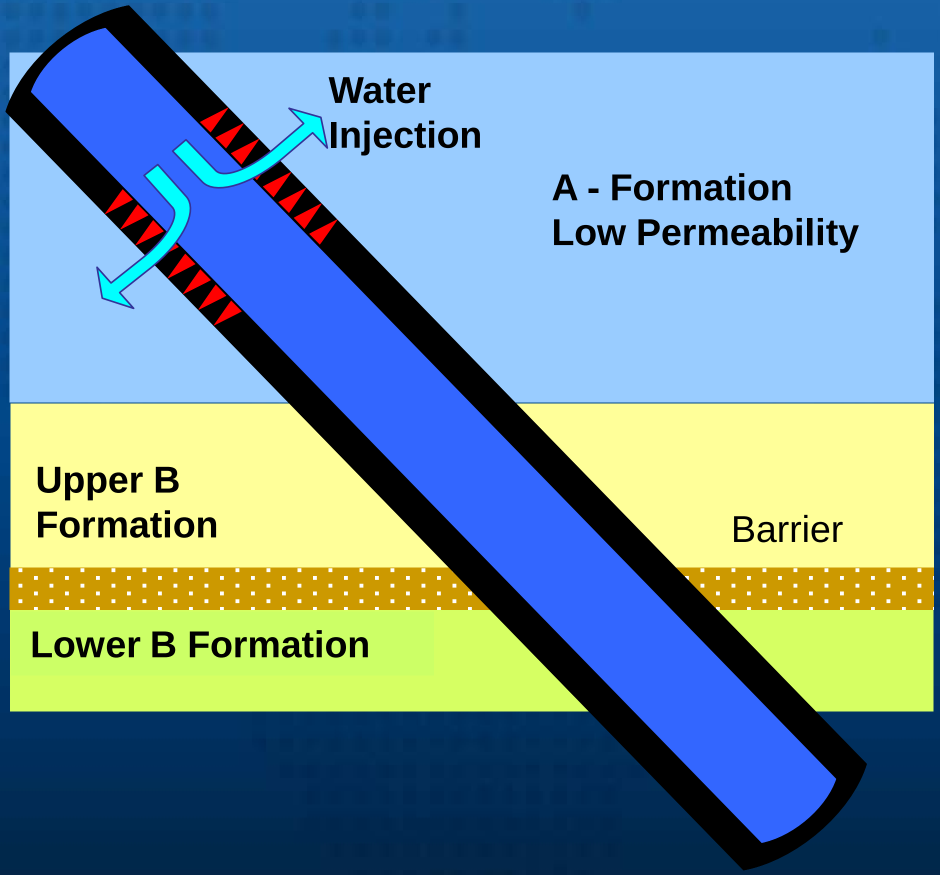
- Two hours of injection into the upper A formation followed
- The CHDT gauges reacted directly and consistently to the injection

- Drilled hole successfully plugged off and tested
- Upper B formation definitively in pressure communication with A formation

Case 2 – Testing upper B formation



Case 2 - Testing communication between zones

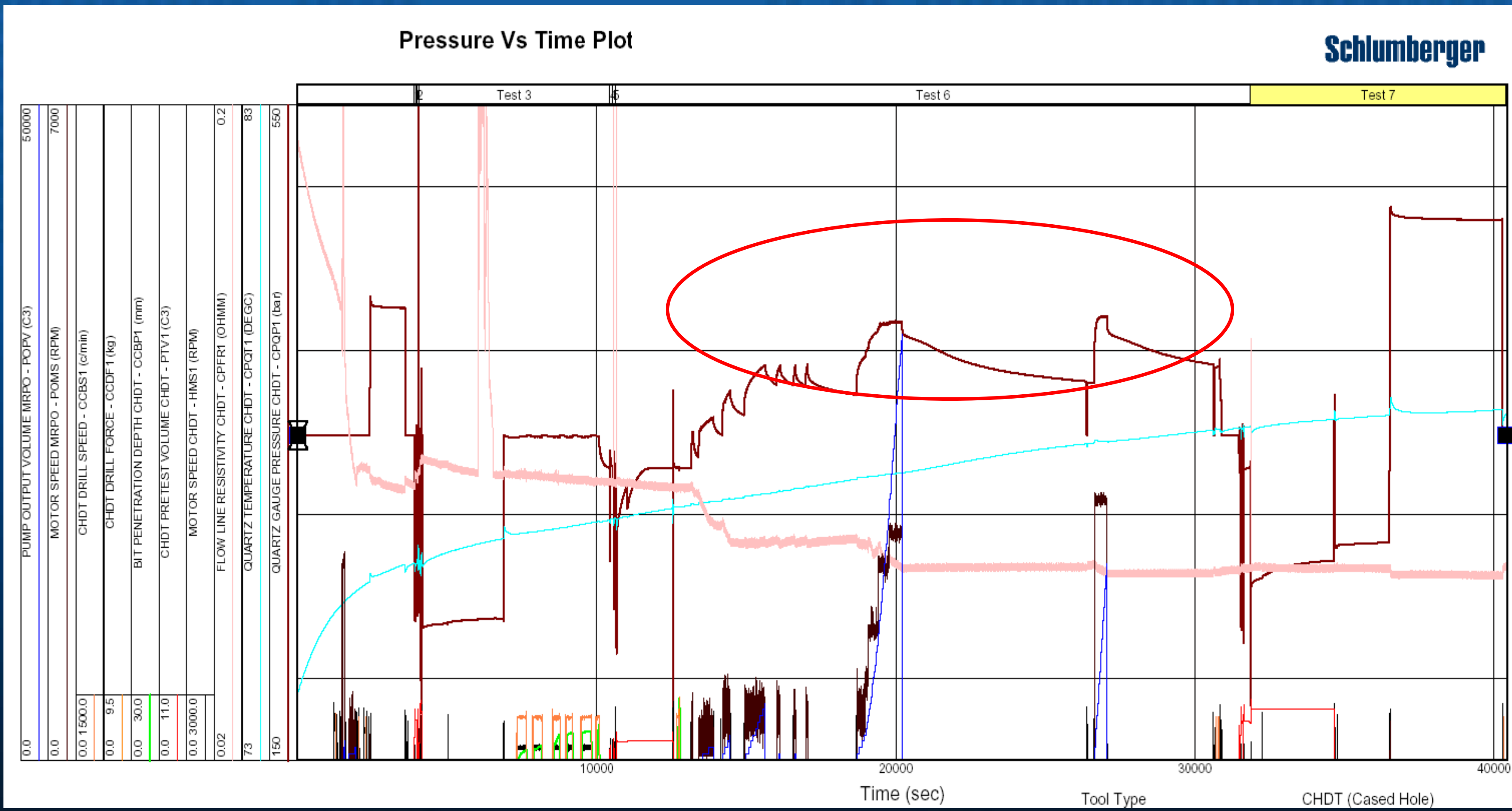


- Maximum formation pressure in both upper and Lower B formation measured
- Barriers between lower B, Upper B and A formation redefined

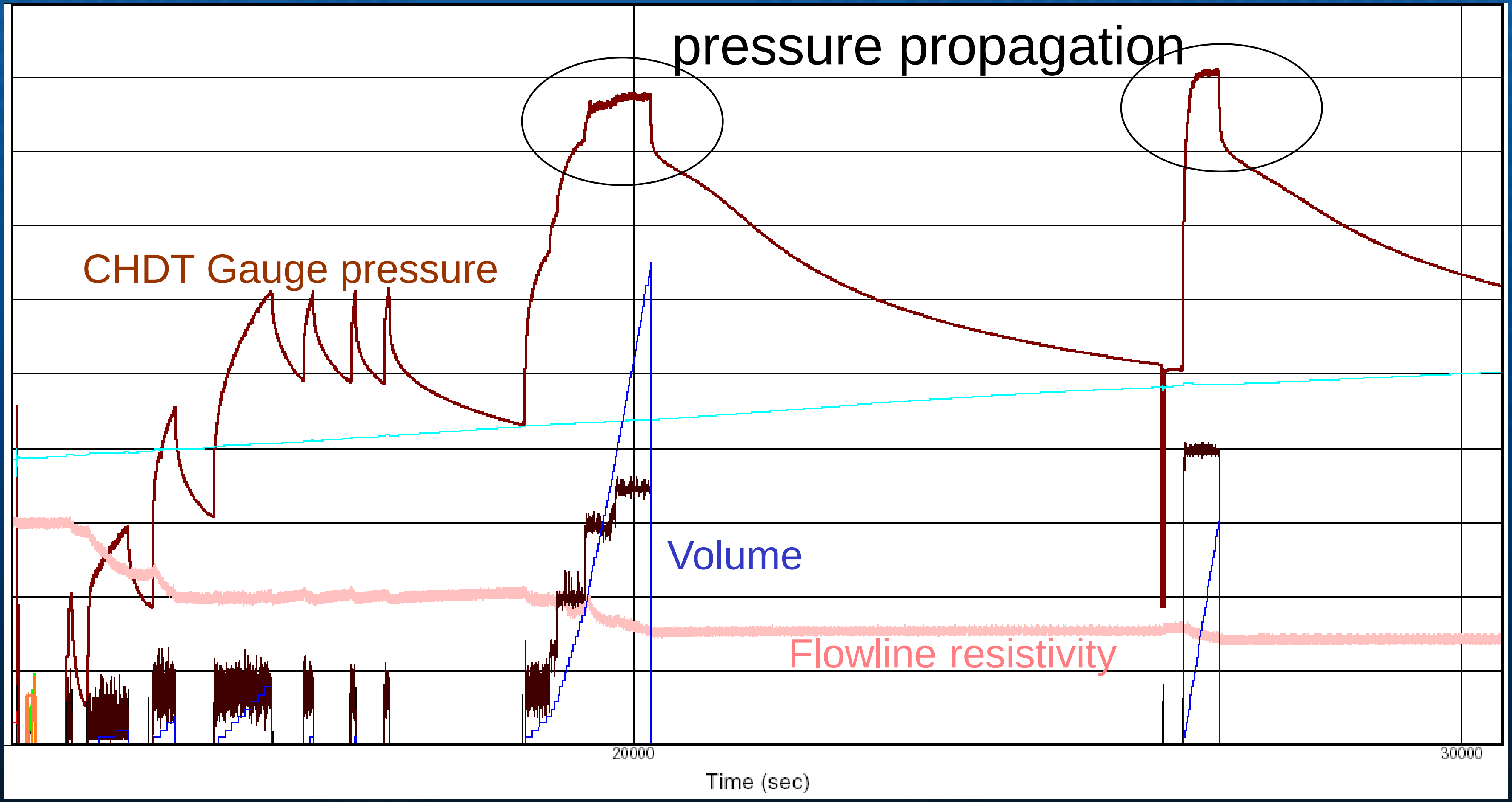
Case 3, CHDT shale integrity testing

- Poor isolation due to bad cement job could result in plugging back and side tracking of this well
- Overburden shales are relatively weak and prone to collapse in this field.
- If the weak overburden shale had collapsed around the casing and if it could be tested for integrity then it may be classified as a well integrity barrier, saving a sidetrack.
- Isolation Scanner used to identify collapsed shale. Then shale was “stress tested” with use of CHDT tool, confirming shale integrity and it’s average stress.

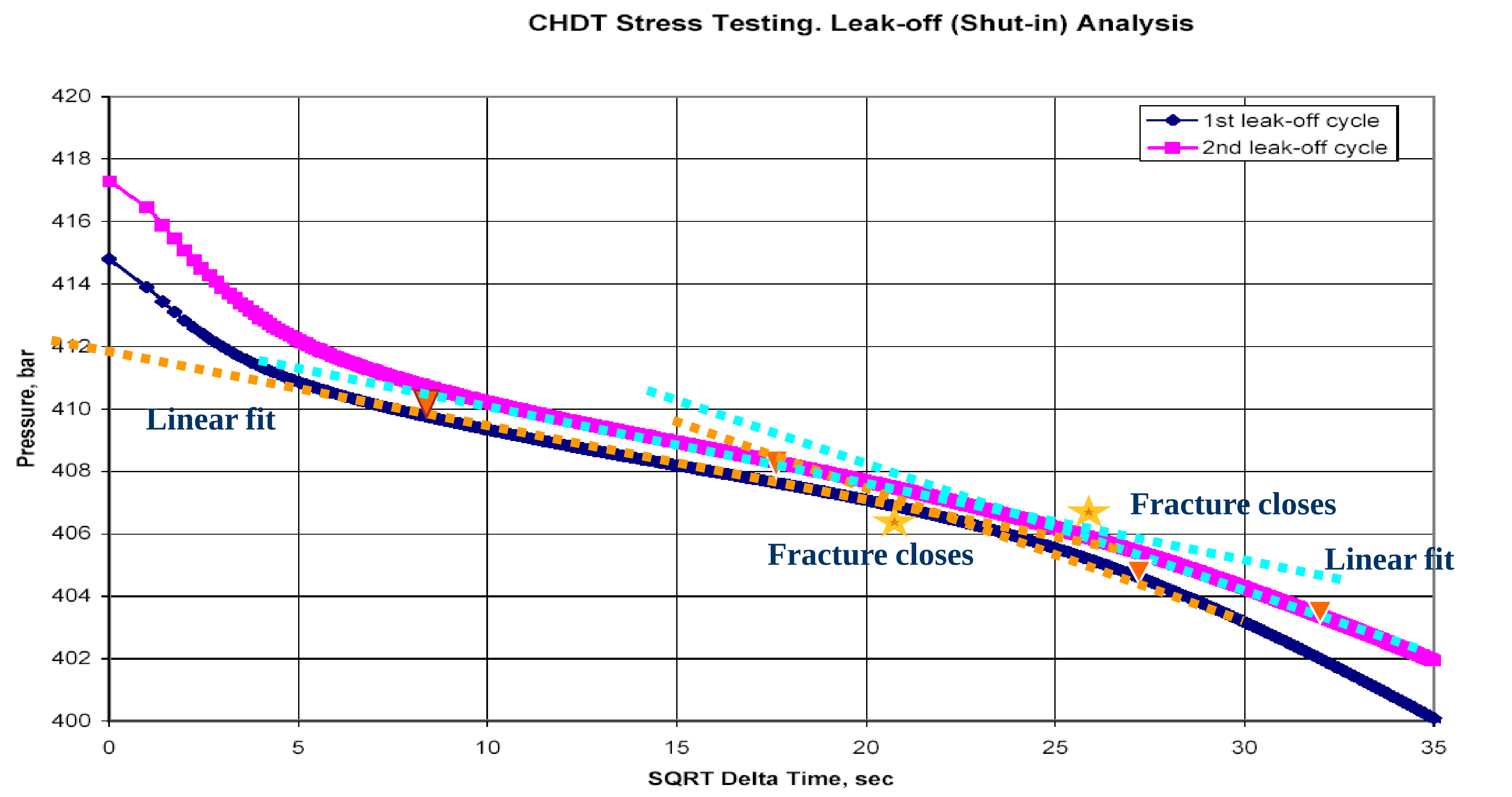
Case 3, CHDT Shale Integrity Testing



Case 3, CHDT Shale Integrity Testing



Case 3, CHDT Shale Integrity Testing



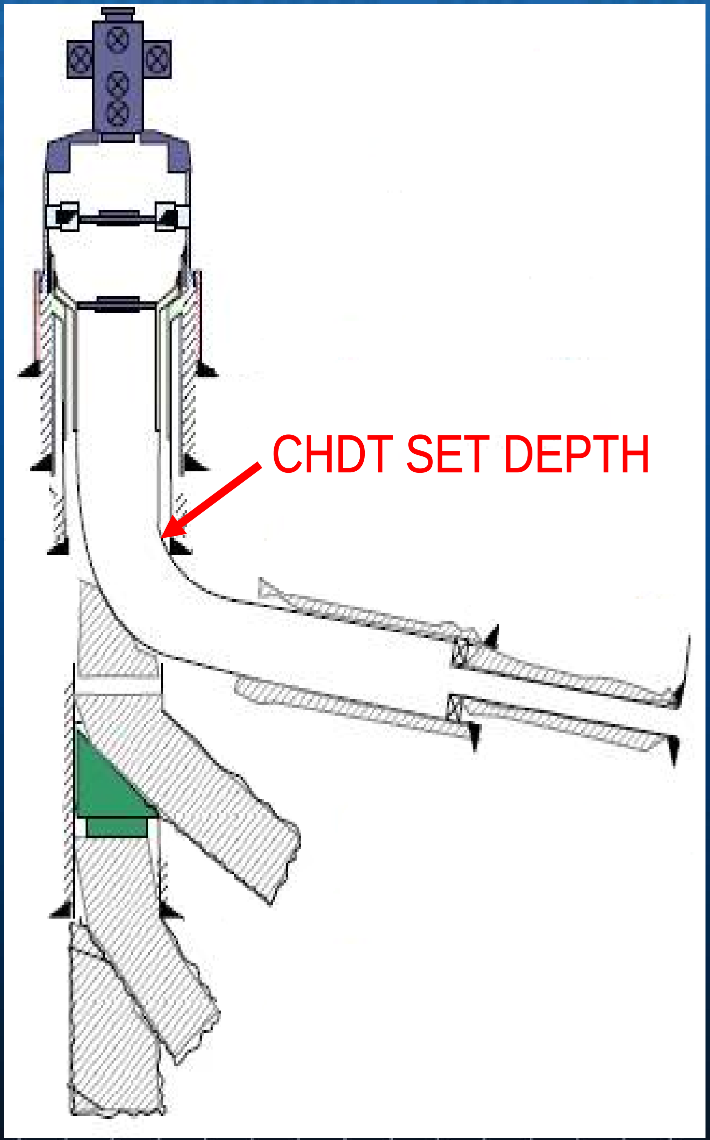
Case 3, CHDT Shale Integrity Testing

The stress-testing results, confirmed over two cycles, suggested that:

- there is no communication through the annulus
- the collapsed shale provided zonal isolation. The results of the job satisfied the annular barrier regulations.

The operator did not have to side track the well.

Example 4 - Problem



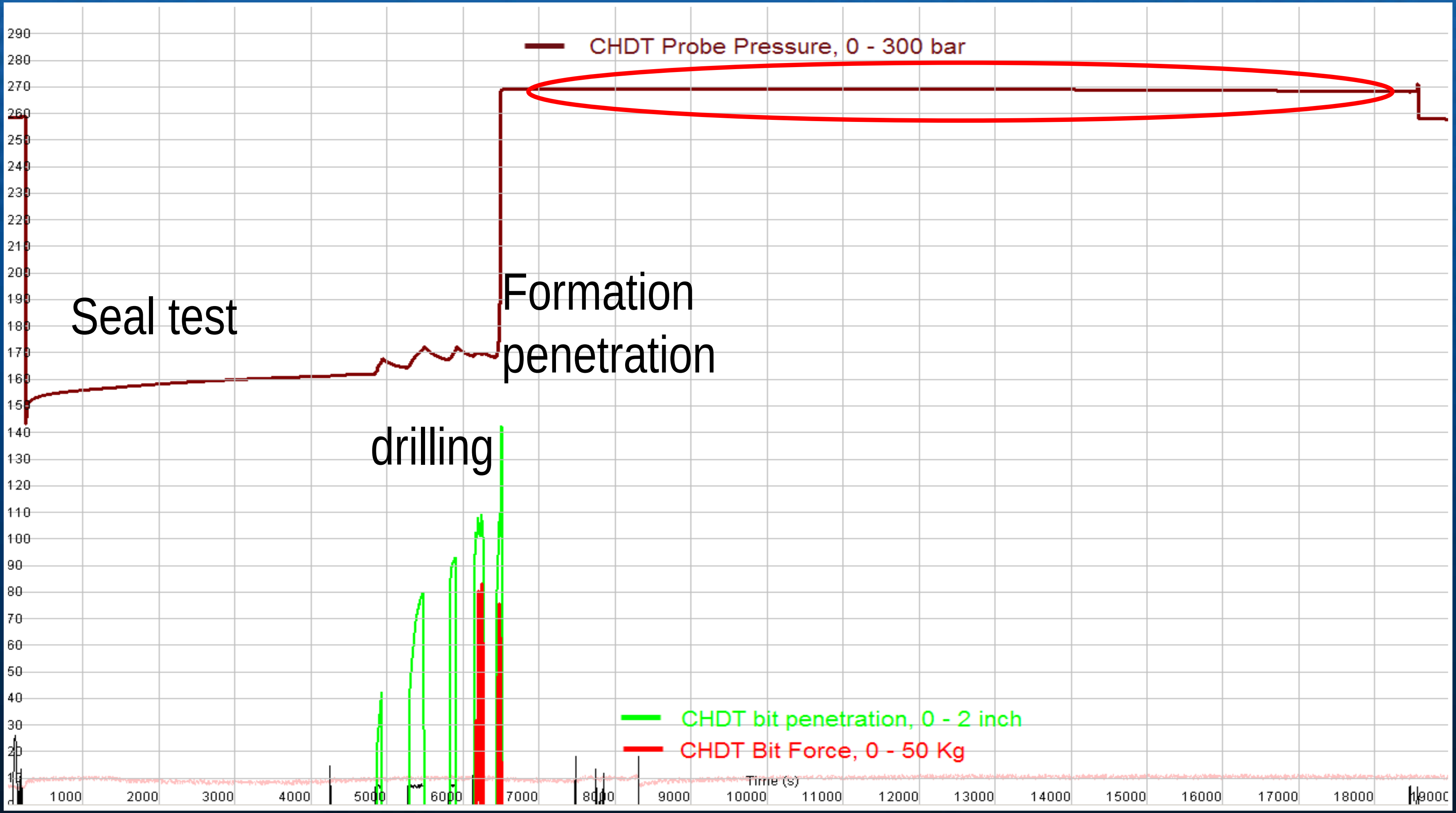
Problem

- Wellbore annulus pressurized due to leaky cement
- Annulus production rate 2,7l/min crude oil
- Unknown pressure behind 9 5/8” casing
  - Possibly to high for casing milling
  - Annulus fluid type unknown without pressure
  - Origin of the leak required fluid type
  - Bottoms up circulation, required for accurate fluid identification, would require over 1 year.

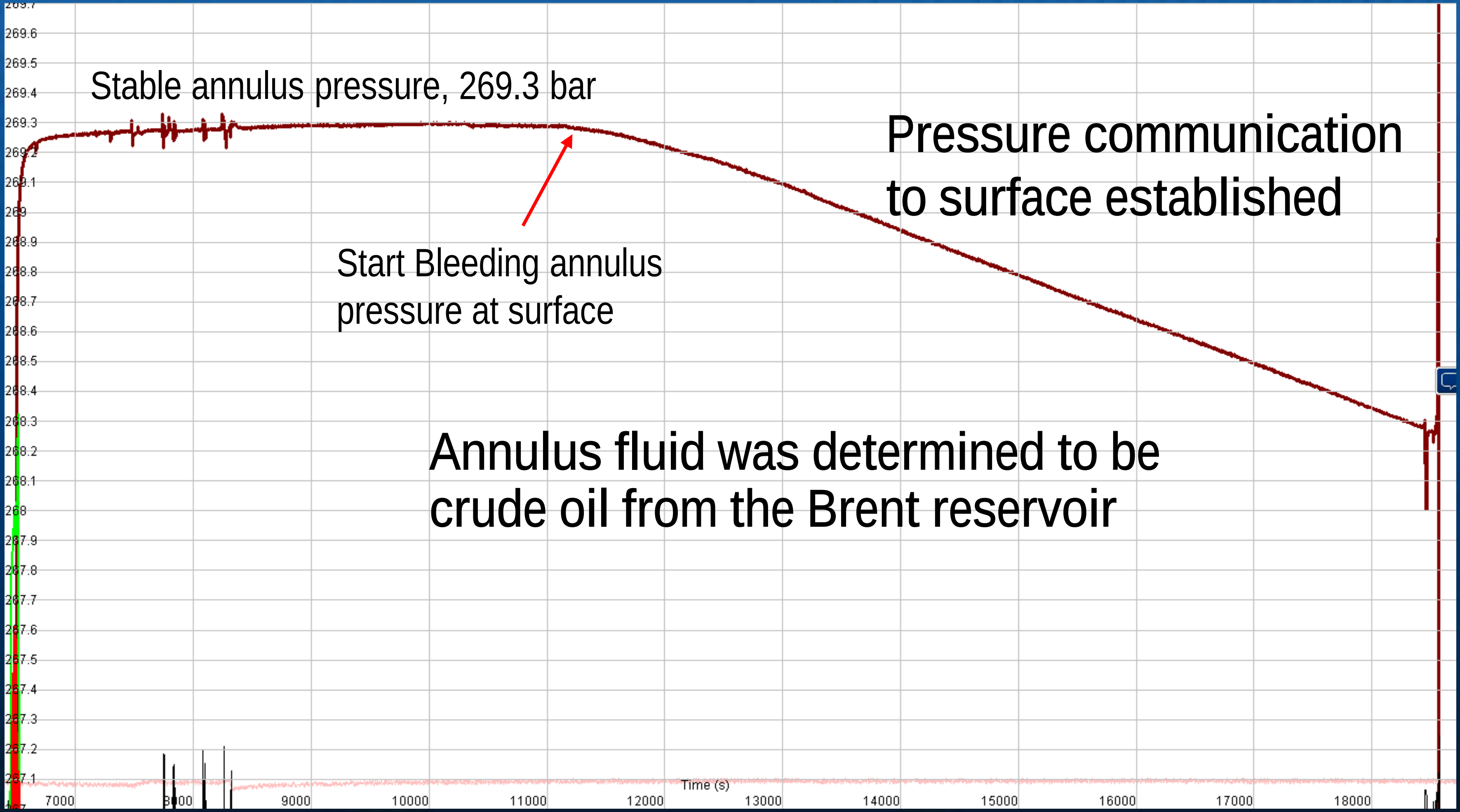
Solution

- CHDT on TLC to measure annulus pressure
- From depth & Pressure the annulus fluid type and origin can be determined

Example 4 - CHDT station data



Example 4 - zoomed CHDT data



Conclusions

Cased hole formation testers have been successfully used for many formation testing and sampling applications.

The following Zonal Isolation examples were discussed:

- Cement Integrity
- Formation Integrity
- Annulus investigation

6th Well Bore Integrity Network Meeting

Alberta ERCB

Investigation of the Joslyn Creek SAGD Surface Steam Release of May 18, 2006

The Hague, The Netherlands

April 28-29, 2010

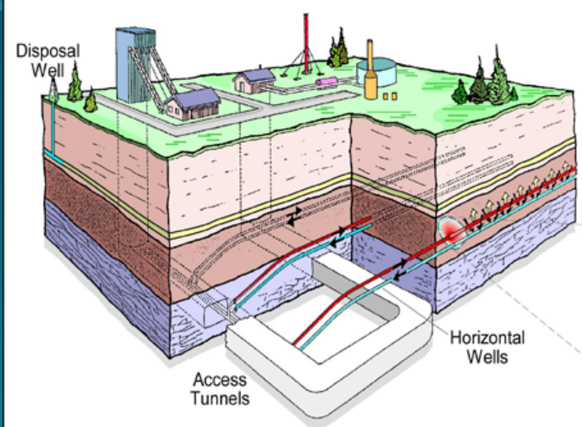
Dr. Fran Hein, P.Geol.
Chief Geologist, ERCB

Bulletin 2010-10 Investigation The Steam Release

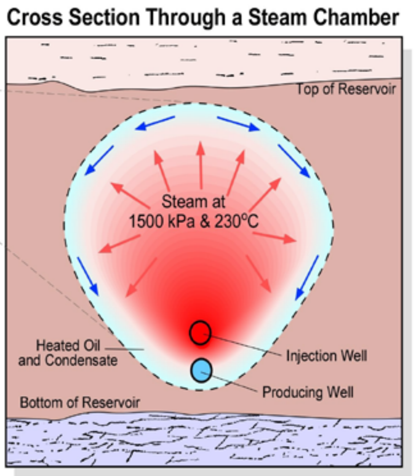
- Catastrophic explosion lasting ~ few minutes.
- Surface crater disturbance ~ 125 m by 75 m.
- Surface uplift & subsidence.
- Tensile cracks & rotated ground.
- Ejection significant volume of soil, caprock, bedrock & bitumen dust.
- Boulders & rocks travelled ~300 m horizontally and at least that vertically.
- Total volume of displaced material overlying soil ~ 1400 - 1700 m3.
- Significant subsurface volume of displaced material underlying soil.

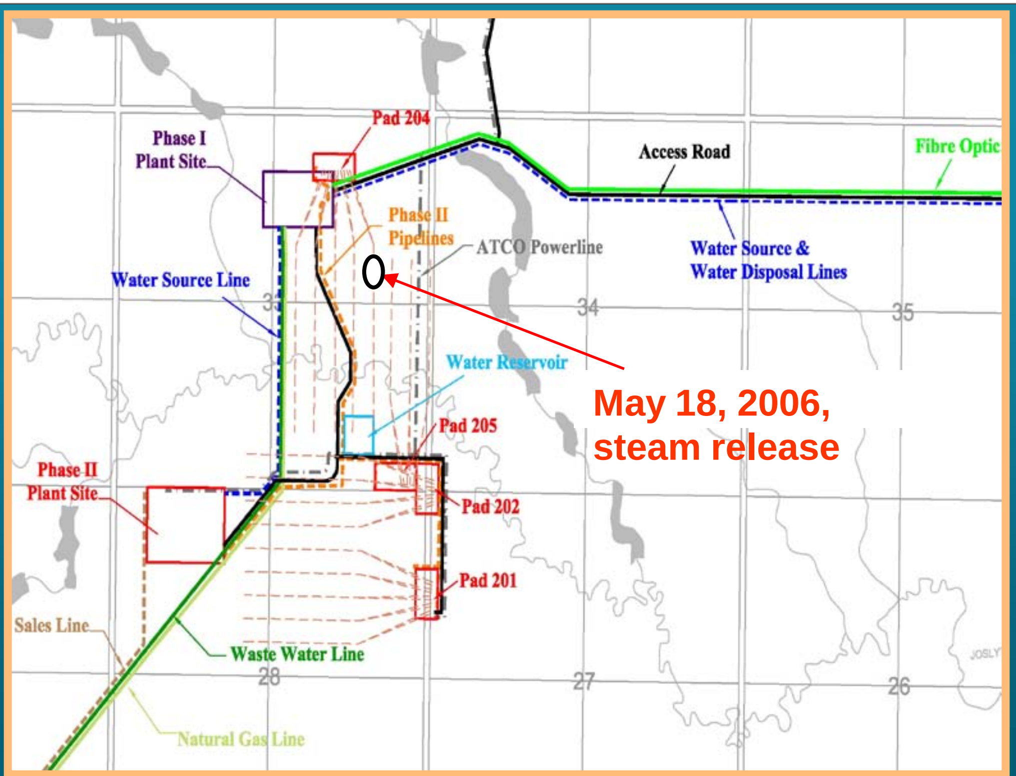
- Blowouts rare in Alberta. 2008: 0.118/1,000 non-aband.wells.
- In 2009 ERCB had 21, 578 field inspections @ energy facilities.
- Joslyn Creek: Only time a SAGD has had a caprock breach steam release to surface.

ERCB Energy Resources Conservation Board



In-Situ Bitumen Thermal: Steam-Assisted Gravity Drainage (SAGD)





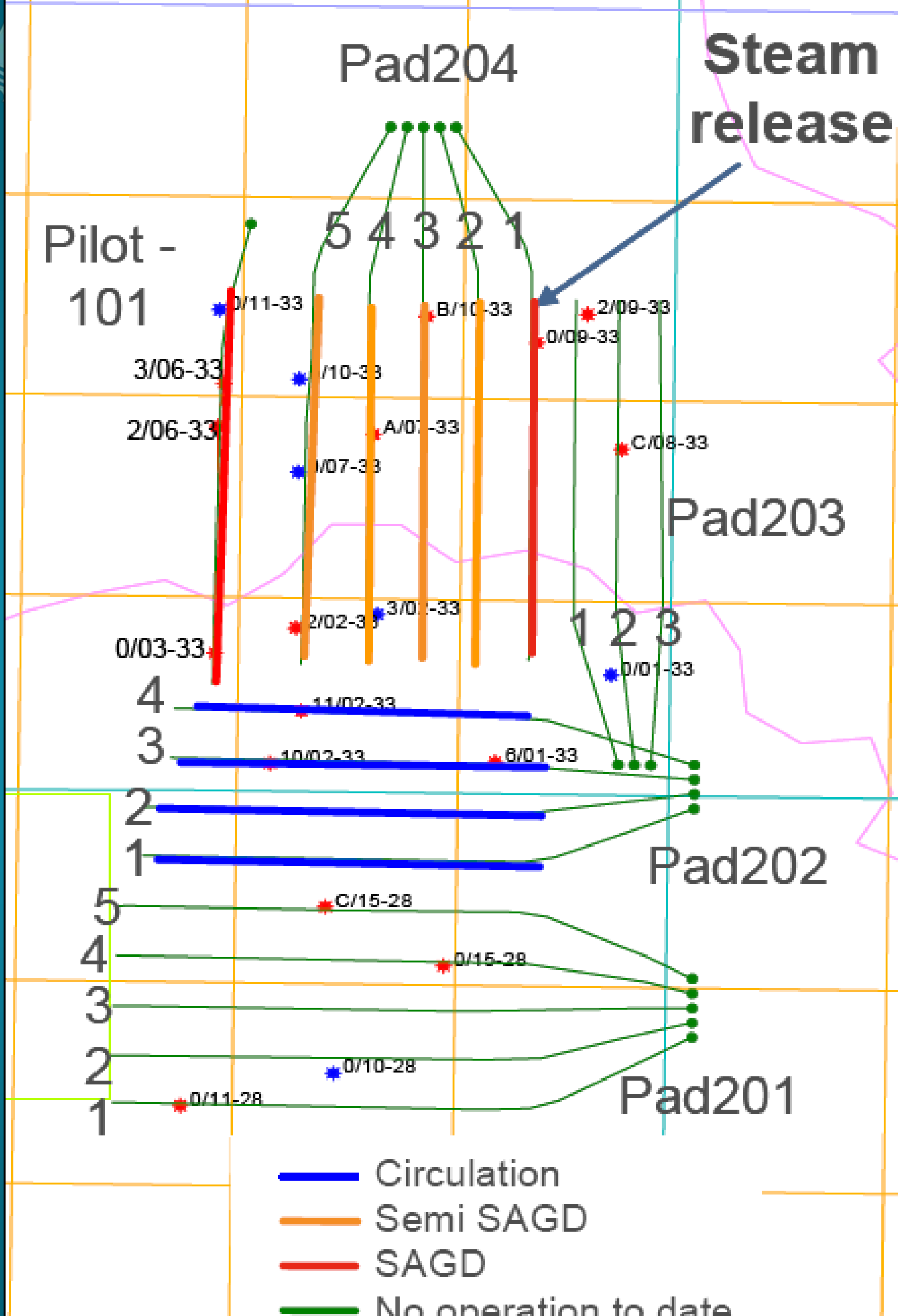
Vertically rotated beds Cretaceous Clearwater Formation 'caprock'

(based on lithology & marine fossils)

ERCB Energy Resources Conservation Board

Damage to a surface pipeline west of the release. The impact was on the top and west side of the pipeline indicating the rock that did the damage must have had a fairly vertical trajectory (went up and over the pipe-line and denting it on the far side of the incident event)

Map of displaced material on surface to varying degrees (including dust plume of pulverized bitumen, rock fragments and projectiles)



Pre-Release Operations

Well Pair 204-I1P1:

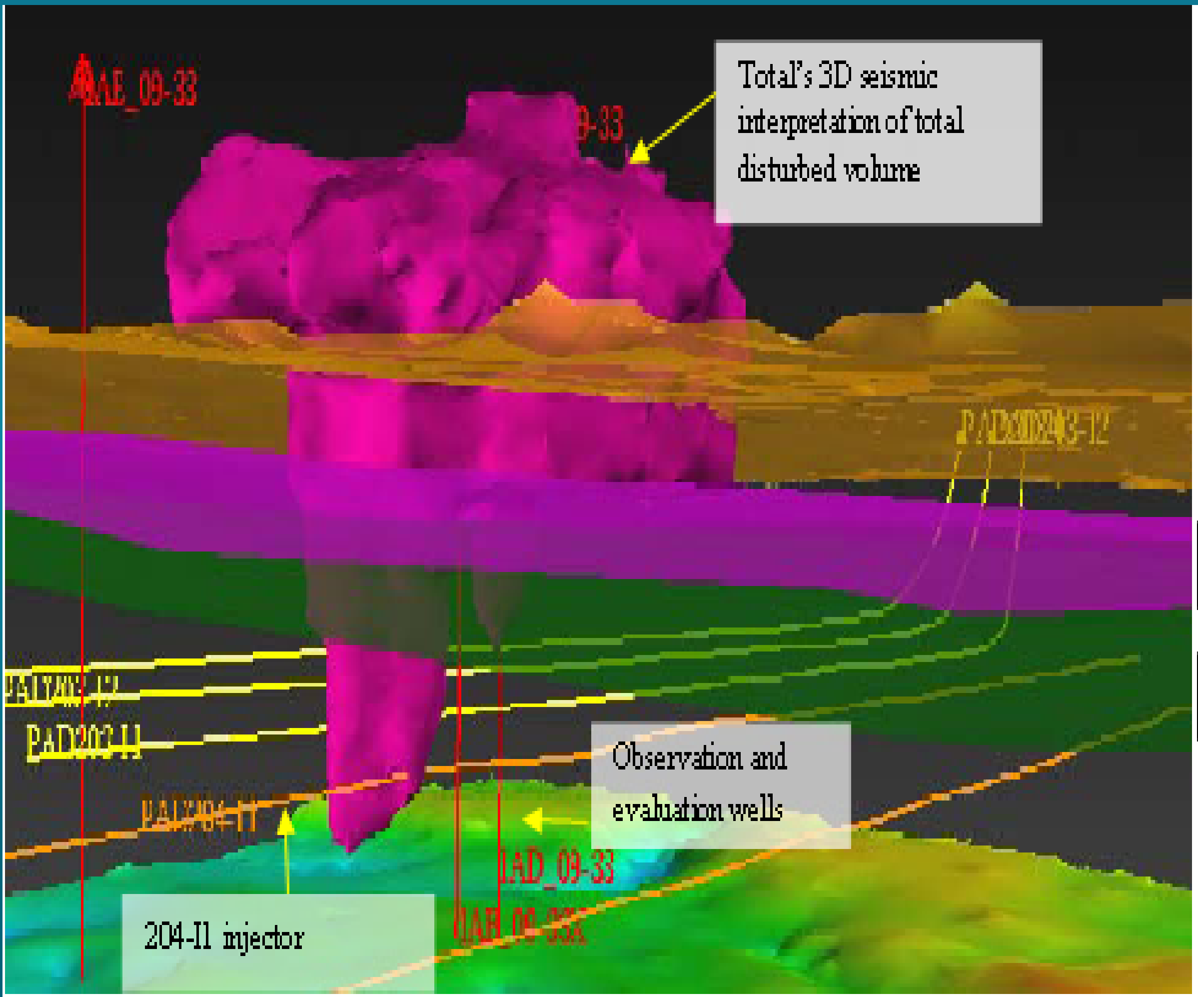
- On circulation 4 months with pressures often reaching estimated fracture pressure of 1700 kPag at well depth.
- On semi-SAGD for about one month with pressures often reaching fracture pressure. After the first two weeks there were indications of fracture/shearing events.
- Well pair shut in to install pump, then operated in full SAGD mode. Step-wise steam rate increases while bhp increased to 1400 kPag.

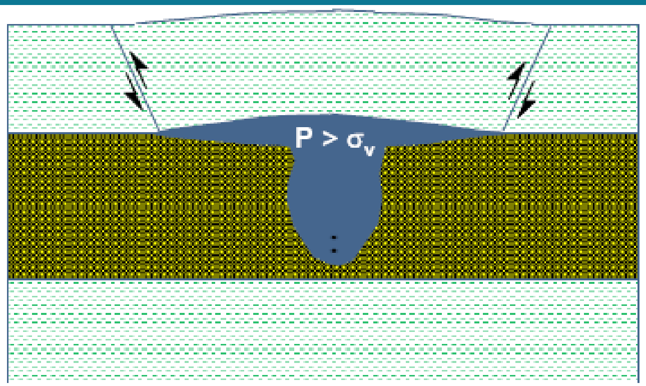
➢ **May 18, 2006**

➢ **Steam Release.**

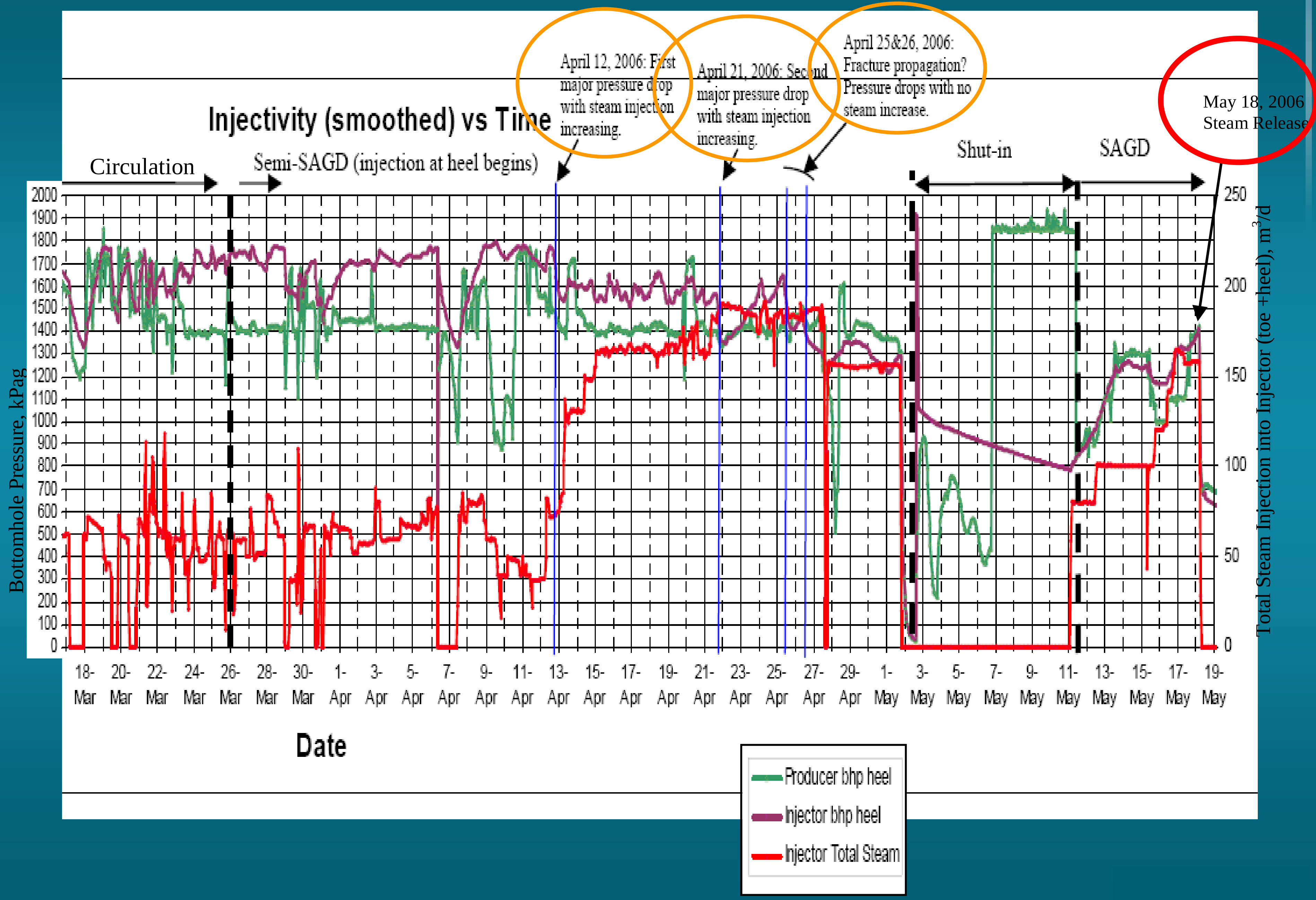
Most-Likely & Possible Steam Release Scenarios

• **Excessively high operating bottom hole pressure during circulation and semi-SAGD, peaking at about 1800 kPag (Est. fracture pressure from mini-frac test was ~1700 kPag at well depth).**

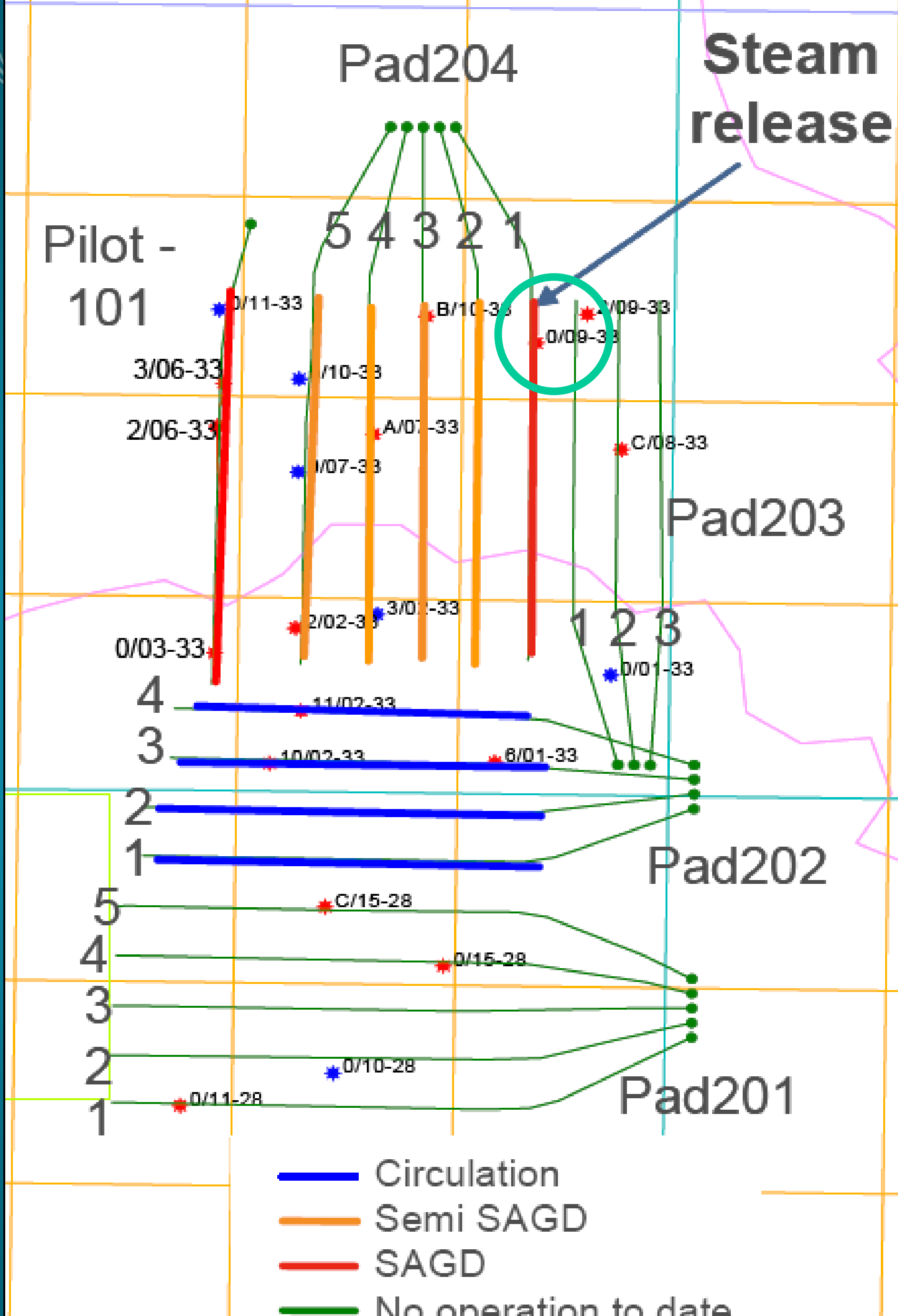




Pool of steam and water above overburden stress grew under the shale barrier, causing the shale to heave upwards significantly, with the maximum shear strain and stress located along the shoulder of the heaved area

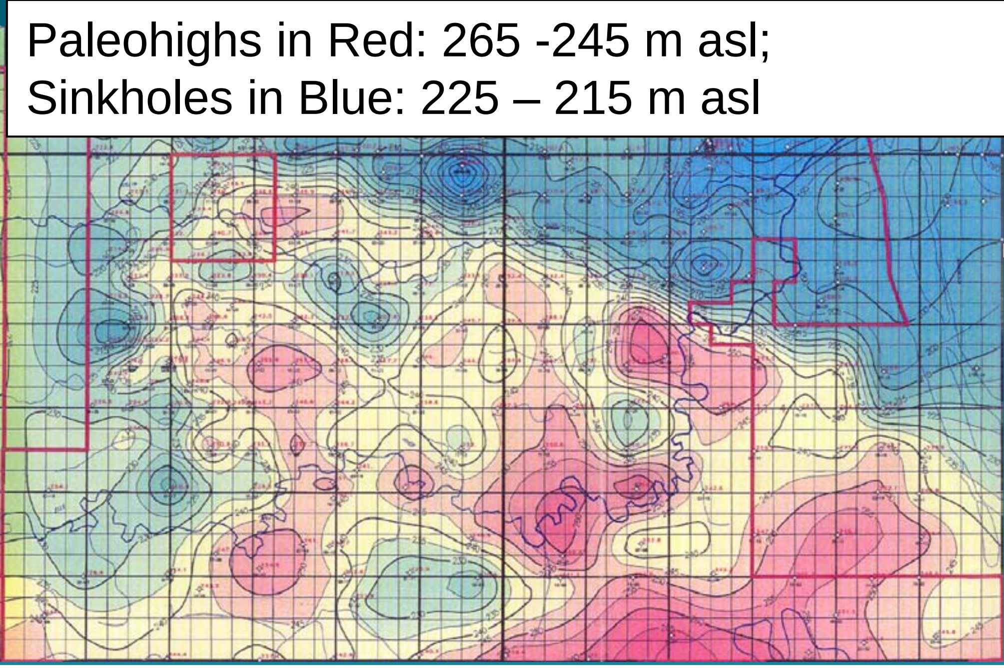

Injectivity (smoothed) vs Time
Circulation
Semi-SAGD (injection at heel begins)
April 12, 2006: First major pressure drop with steam injection increasing.
April 21, 2006: Second major pressure drop with steam injection increasing.
April 25&26, 2006: Fracture propagation? Pressure drops with no steam increase.
Shut-in
SAGD
May 18, 2006 Steam Release
Bottomhole Pressure, kPag
Total Steam Injection into Injector (toe +heel), m³/d
Date
18-Mar 20-Mar 22-Mar 24-Mar 26-Mar 28-Mar 30-Mar 1-Apr 3-Apr 5-Apr 7-Apr 9-Apr 11-Apr 13-Apr 15-Apr 17-Apr 19-Apr 21-Apr 23-Apr 25-Apr 27-Apr 29-Apr 1-May 3-May 5-May 7-May 9-May 11-May 13-May 15-May 17-May 19-May
Producer bhp heel
Injector bhp heel
Injector Total Steam

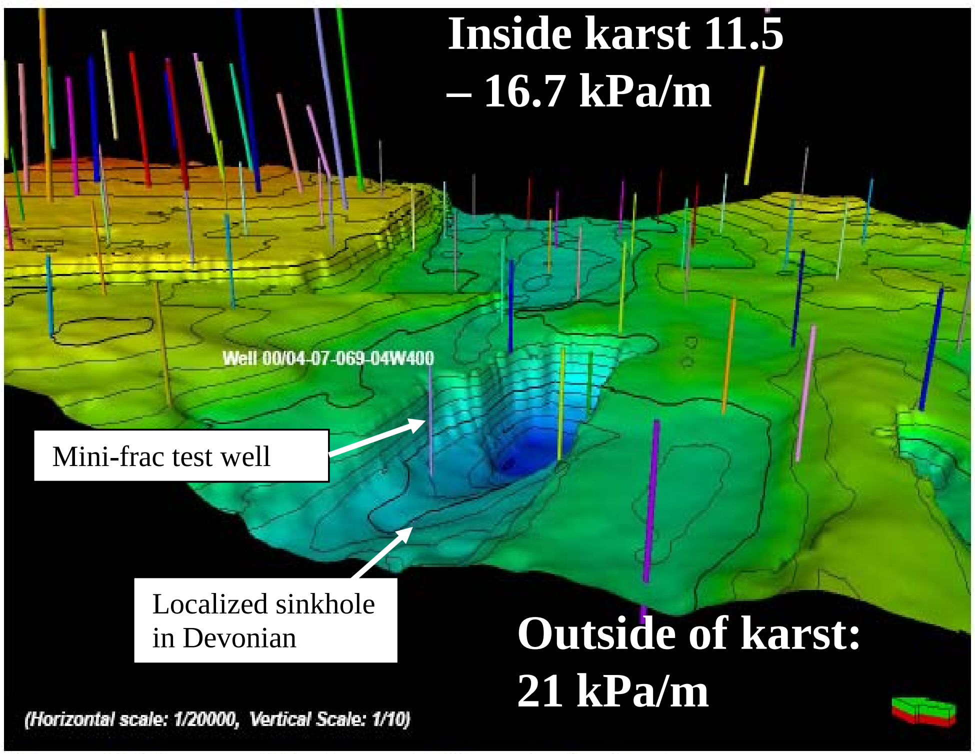
Most-Likely Scenario



- Not coincidental that two **Abandoned Wells** within 20 m of steam release incident (uncemented, never located).
- 3-D seismic interpretation could be a vertical fracture or a "chimney"
- Rather than a localized chimney forming during circulation period, a vertical fracture initiated on April 12, 2006. Fracture could have been associated w/ abandoned well or a pre-existing natural fracture or fault in the area.
- Argument against vertical fracture is mini-frac tests,

However …….





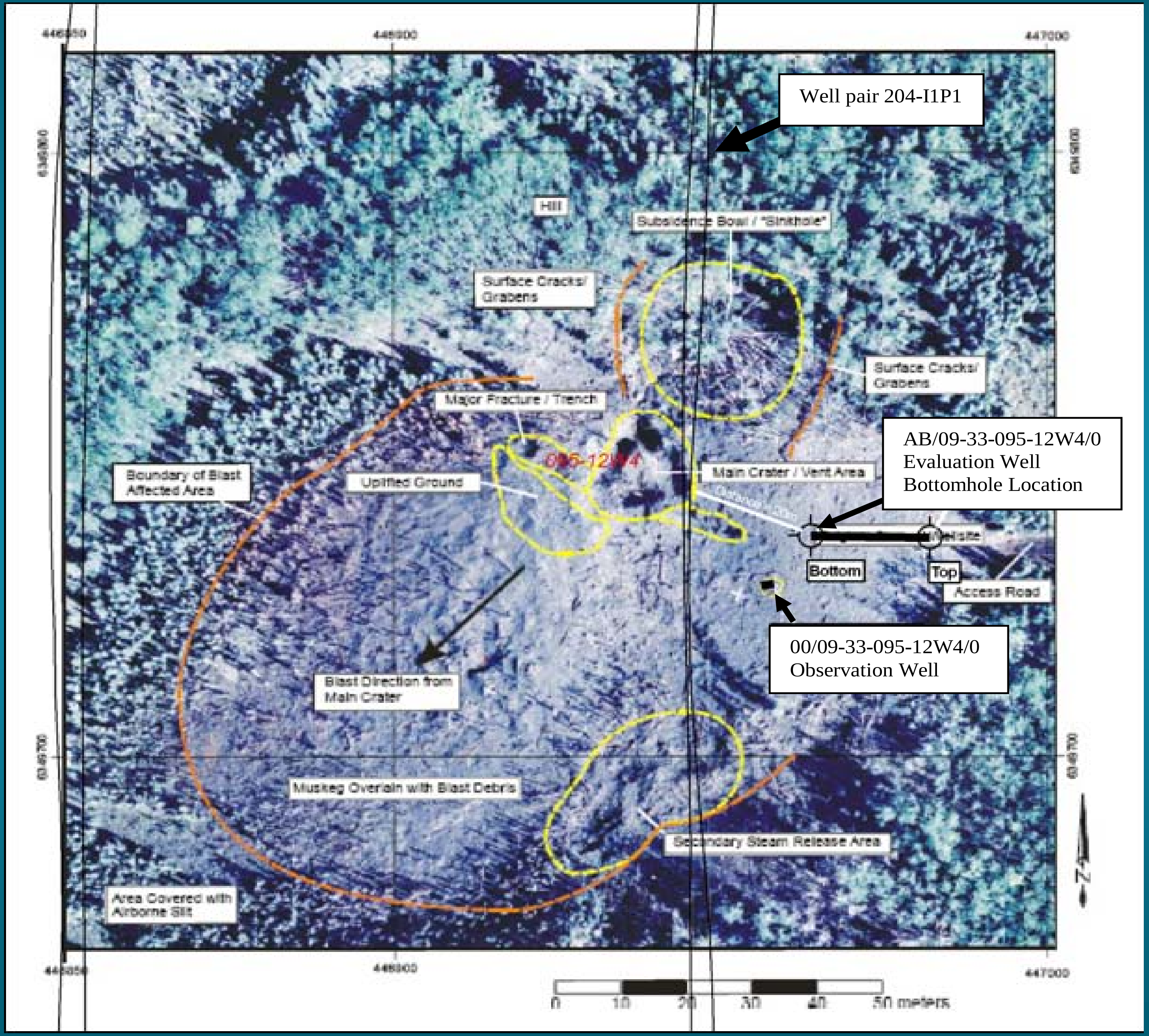
Area is Karst Terrain

- The mini-frac indicated that the vertical stress was only a little lower than the minimum horizontal stress, and the test was done on a well over 1 mile west of release site.

  If karsting reduced the minimum horizontal stress below the vertical stress locally, then a vertical fracture could have occurred.

- **Other Possible Contributing Geologic and Wellbore Issues (See Next Slide)**

Joslyn Ck SAGD Site



Possible Scenario Involving Nearby Vertical Wells

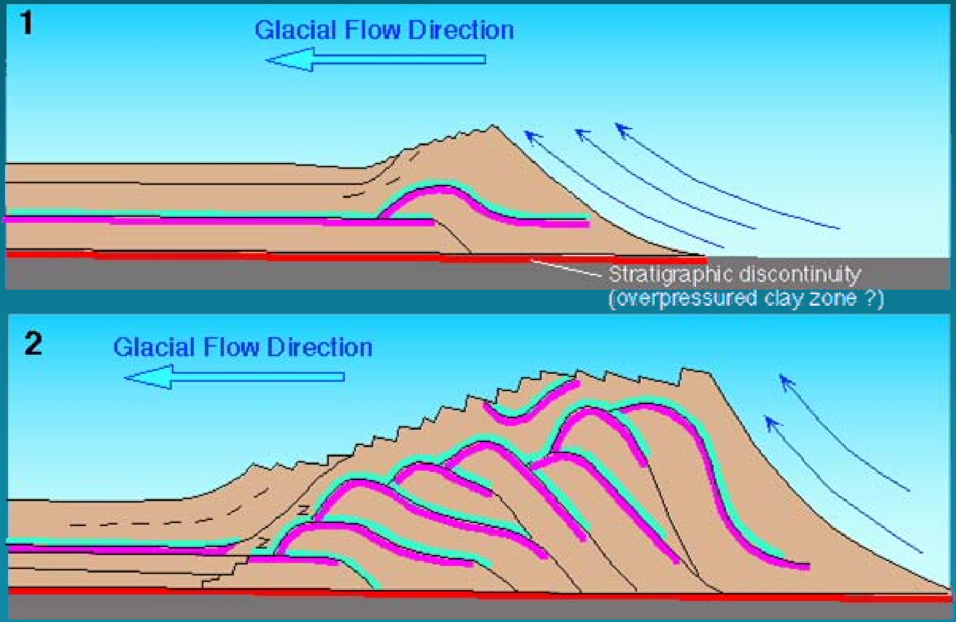
- Breach of caprock in close proximity to two vertical wells; AB/9-33 evaluation well abandonment shows a single-stage plug back and abandonment with no cement returns reported and no tagging of the cement top;

- Well abandonment could have left sections of the hole without cement, providing the steam with a pathway. Cement bond over a clean unconsolidated oil sands zone is not necessarily a seal;

- Possible scenario: horizontal fracture on April 12 moved to the abandoned evaluation well AB/9-33 (the observation well appeared largely undamaged but they could not locate the uncased evaluation well);

- Steam then moved up through gaps or channels in the well's cement abandonment plug until it reached the Wabiskaw C gas sand. After that, the scenario is the same as the most likely scenario.

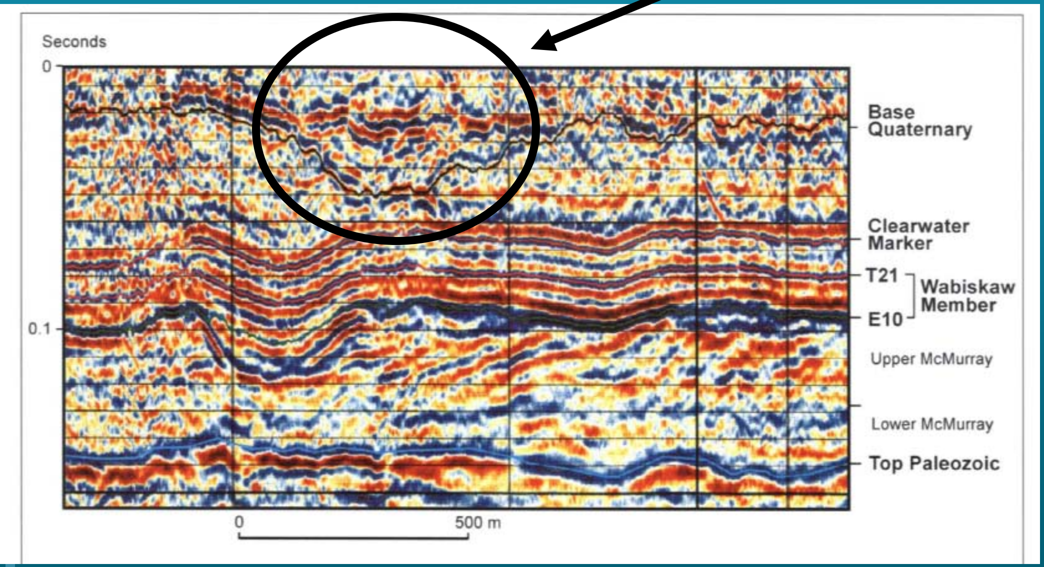
Other Possible Contributing Geologic Factors



- **Glacial Tectonics Associated with Moraines Faulted/Folded Caprock.**

Glacial-Thrust Triangle Zones: Fort Hills, Fort MacKay, Cold Lake

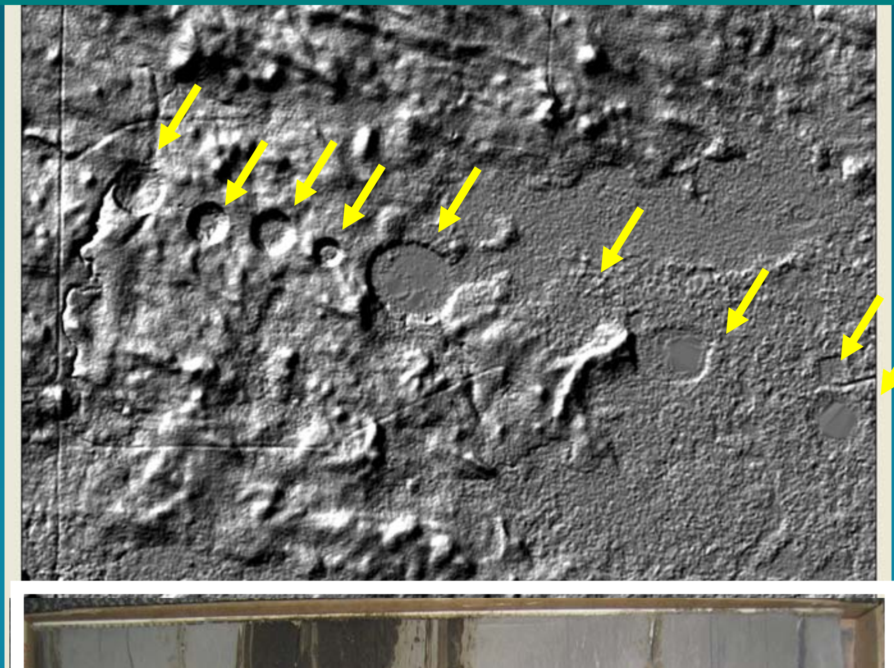
Glacial Bedrock Channels



- **Removal by Glacial Erosion of Previous Caprock by 'Bedrock Channels.'**

(from Langenberg & Hein, 2006)

Other Possible Contributing Geologic Factors



- **Subsidence Tectonics Associated with Karst.**

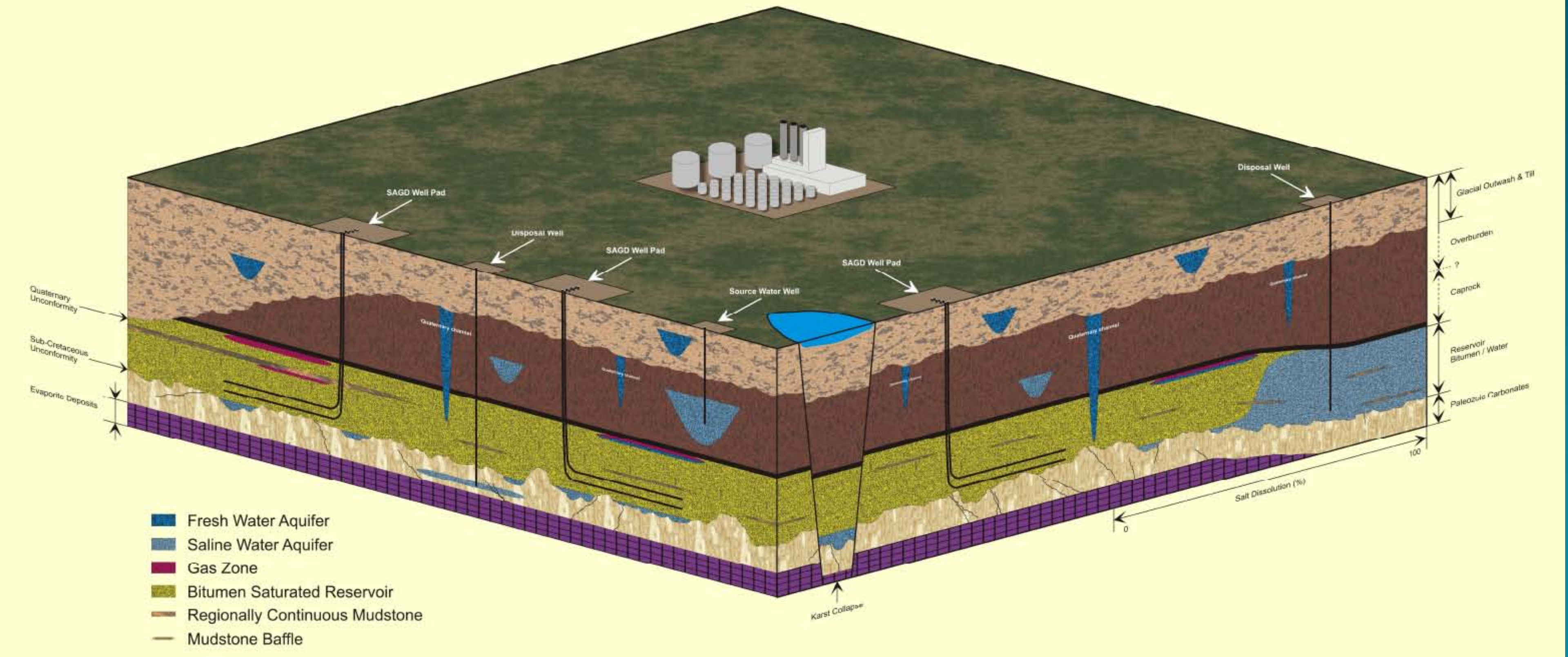
  LiDAR (Light Detection and Ranging) Image North of Joslyn Creek

  Occurrence of pre-existing Faults/Fractures (Vertical Conduit)

- **Sandy Zones within Zone Identified as Clearwater 'Caprock '**

  'Shale' is not really Shale

Photograph of core in area



Athabasca Oil Sands Main Lesson – You Have to Look Beyond Individual Well Bore

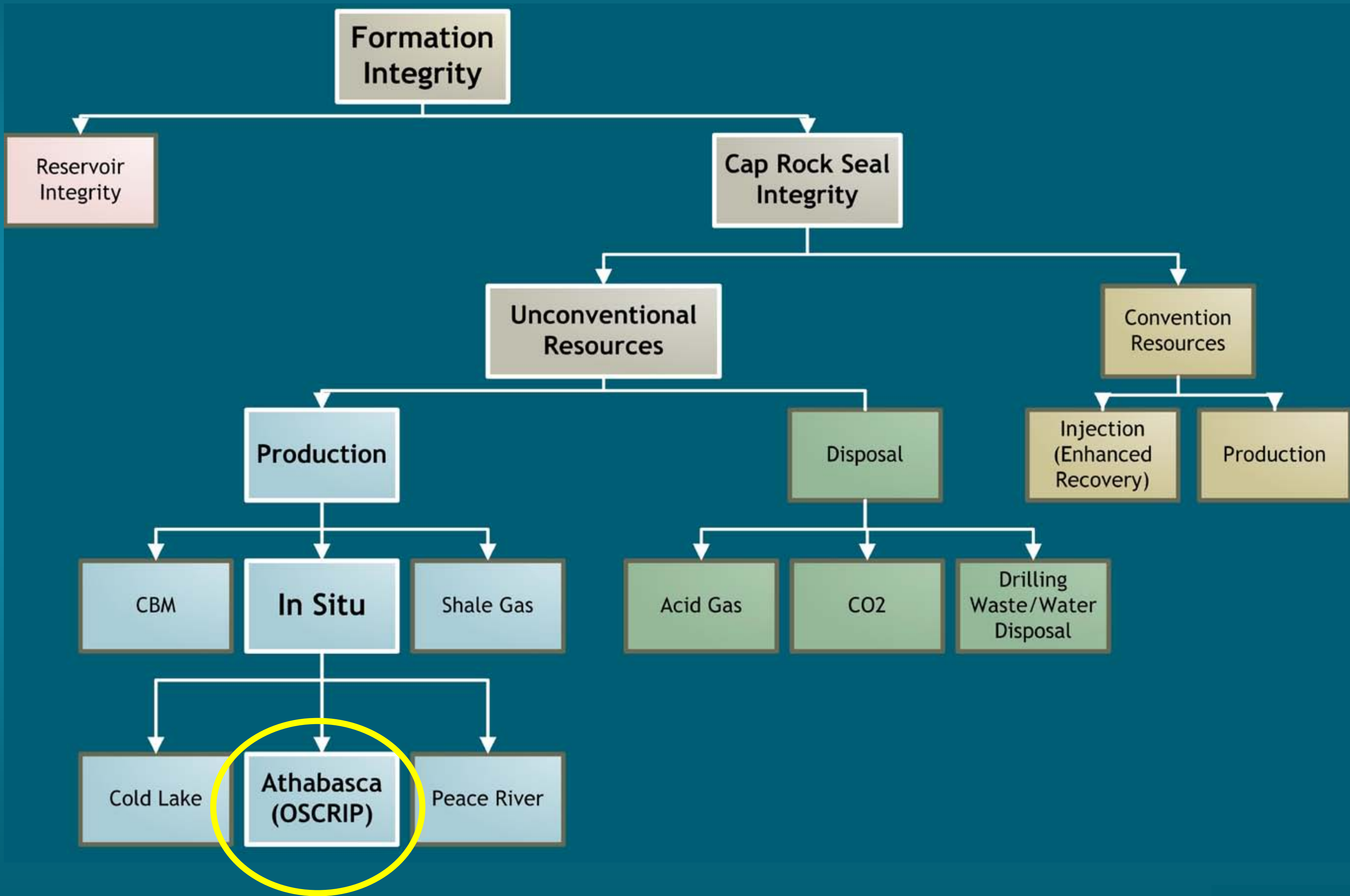
Geological Factors	Athabasca
Salt Dissolution	Dominant to Important
Karsting	Dominant
Bedrock Tectonics	Contributing
Glacial Tectonics	Important
Faulting	Important
Pre-existing topography	Dominant
Caprock integrity	Contributing

ERCB Joslyn Ck Steam Release Investigation

- New ERCB Requirements for Caprock Integrity and Maximum Allowable Injection Pressures Especially in Shallow SAGD Areas;
- Directive 51 (D51) Rewrite and revisions (ongoing);
- Regional Caprock Integrity Study (ongoing): Joint Between Alberta Geological Survey (ERCB Edmonton Office) and ERCB Calgary Office;
- Part of a Developing Program Dealing with Caprock Integrity for other Energy Development (i.e. Tight Gas, Tight Oil, CO2 Sequestration, etc.) in Alberta.

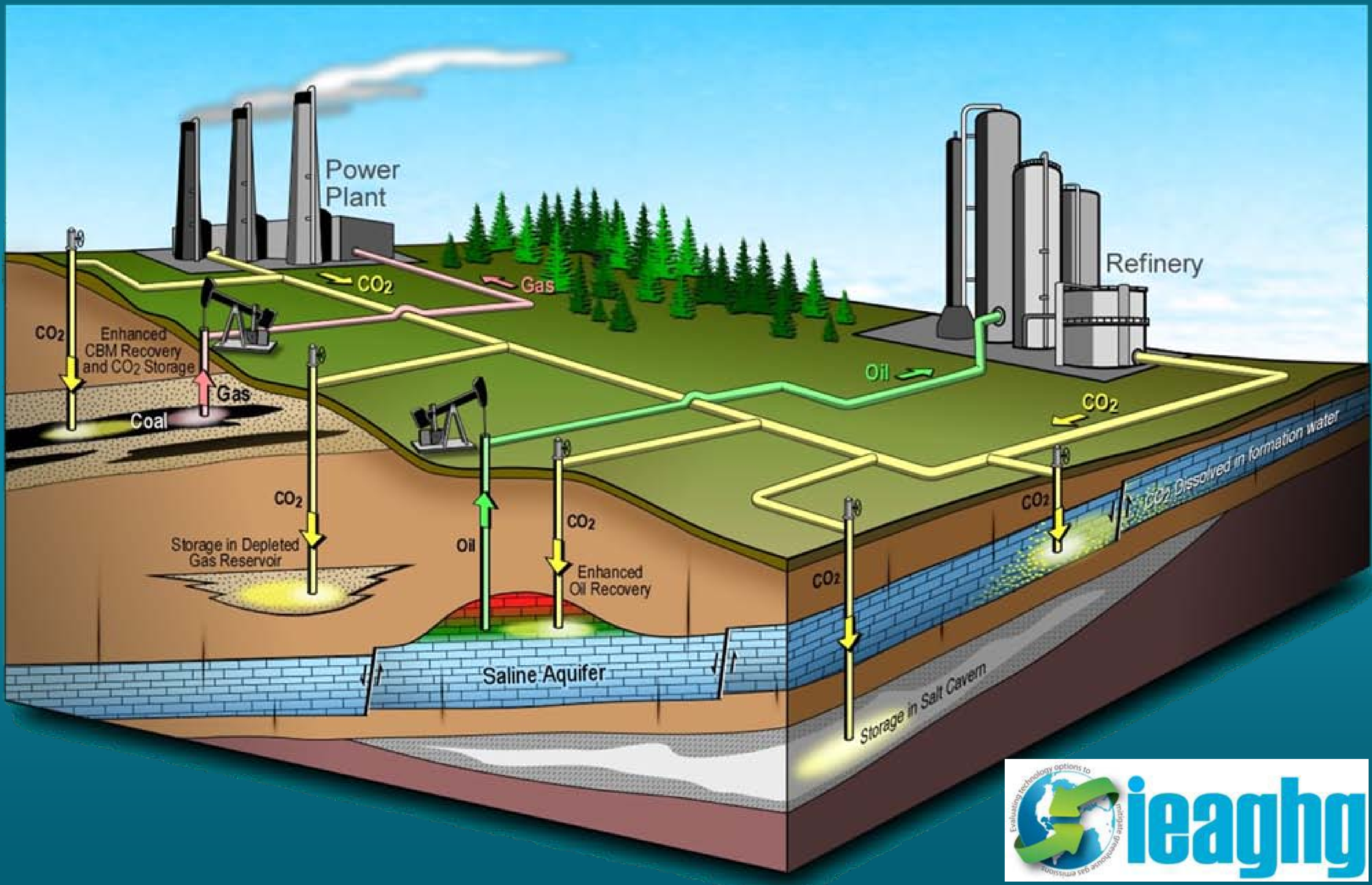
ERCB Formation Integrity Program

Fm integrity : Capacity of geological strata w/stand changes in thermal & stress fields.



ERCB Energy Resources Conservation Board

Similar Strategies Re: Future CO_2 Injection



GFZ

Helmholtz Centre
POTSDAM

CO_2SINK

Permanent Distributed Temperature Sensing at the Ketzin CO_2 Storage Test Site

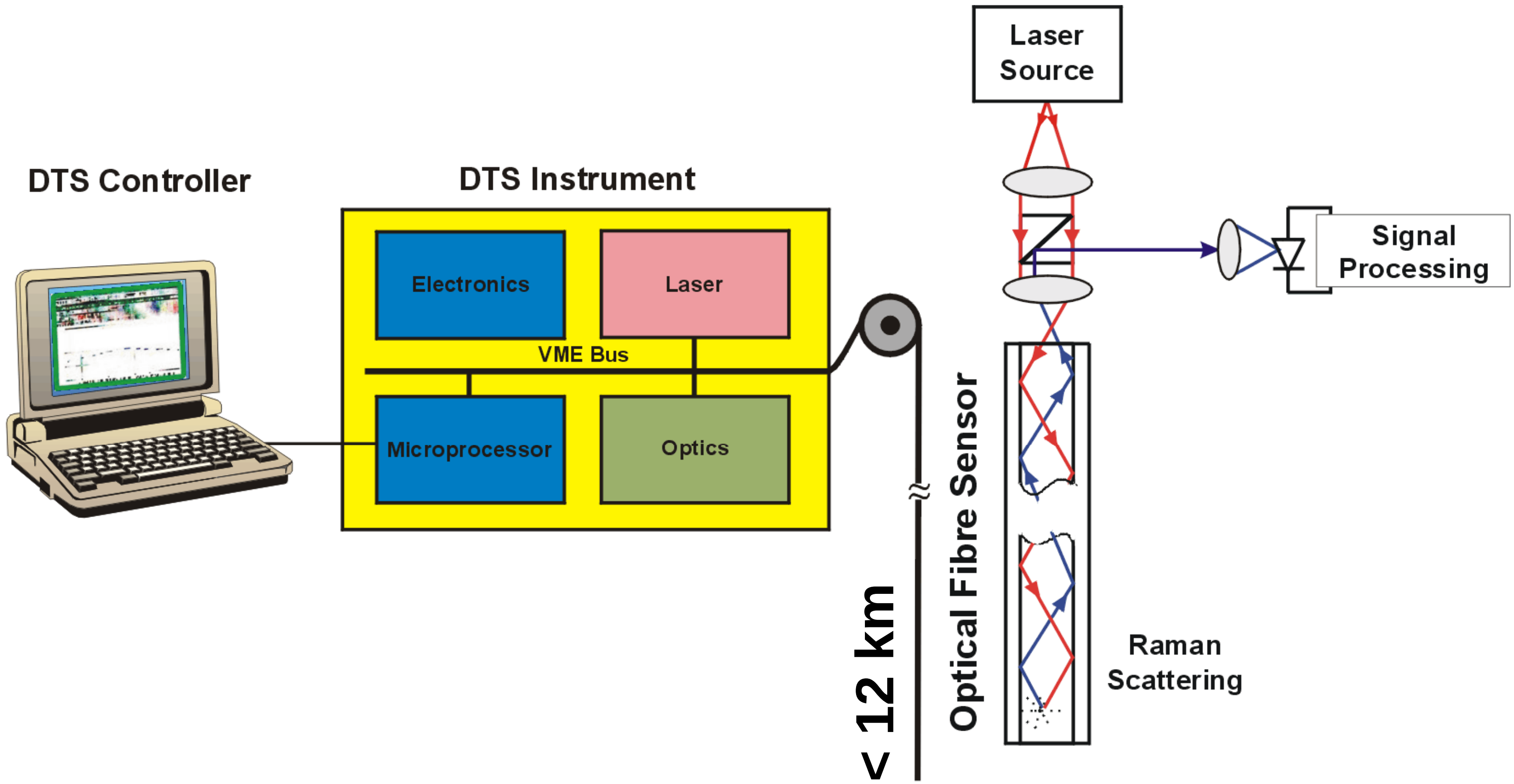
Jan Henninges

ieaghg 6th Wellbore Network Meeting, April 28-29, 2010

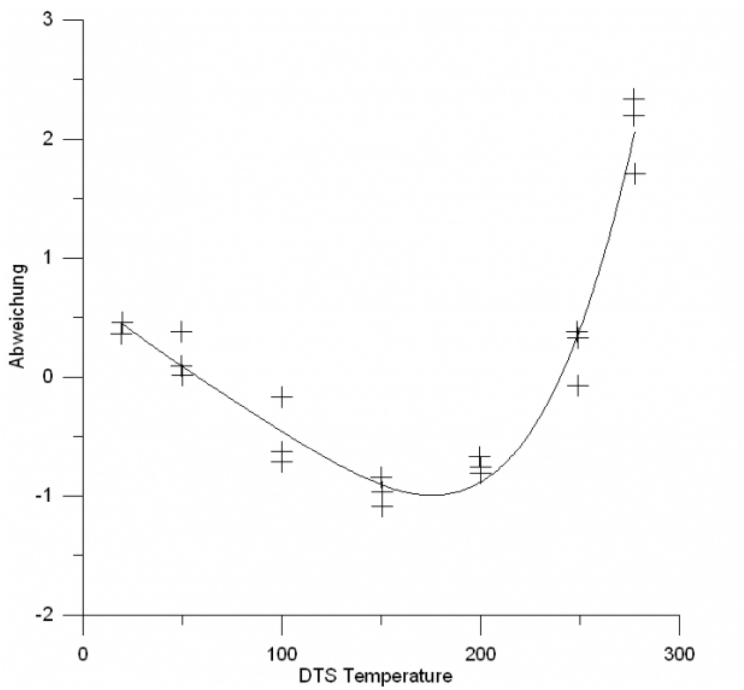
Introduction

- Objectives of temperature measurements at Ketzin:
  - Monitoring of CO_2 migration during injection into a saline aquifer, and
  - the thermal state of borehole and reservoir.
- Methods:
  - Passive: fiber-optic distributed temperature sensing (DTS)
  - Active: heat-pulse measurement (collaboration LBNL)
- Outline:
  - Method of distributed temperature sensing
  - Installation of sensor cables at Ketzin
  - Results from temperature monitoring, with focus on borehole integrity and detection of near-wellbore flow (cementing, CO_2 injection)

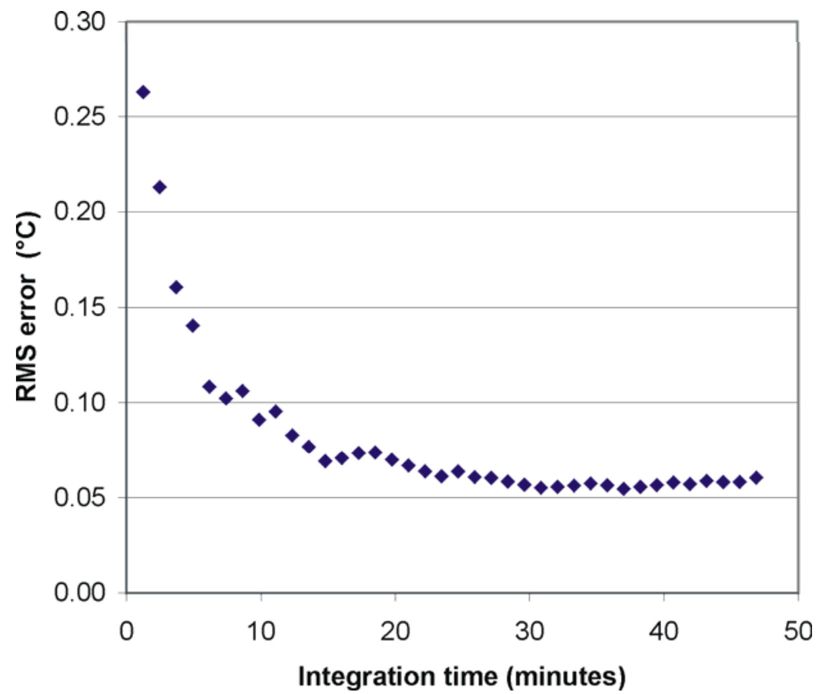
Distributed Temperature Sensing (DTS)



DTS accuracy and precision

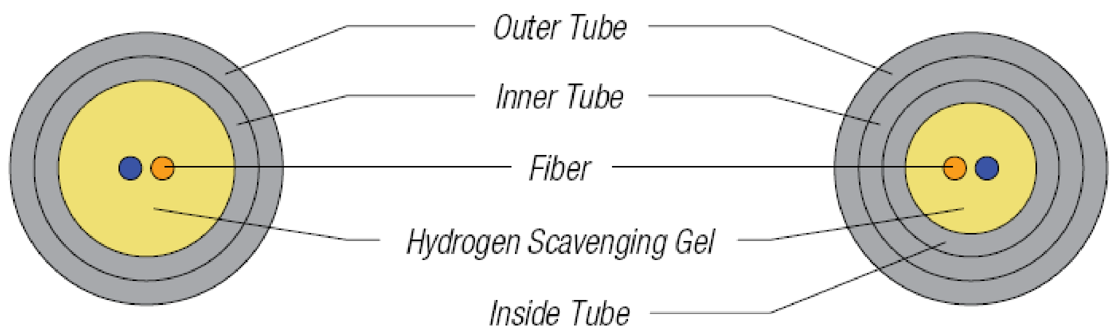


DTS unit: Sensa DTS 800 M10



Fiber length: 2908 m
Spatial resolution: 1 m

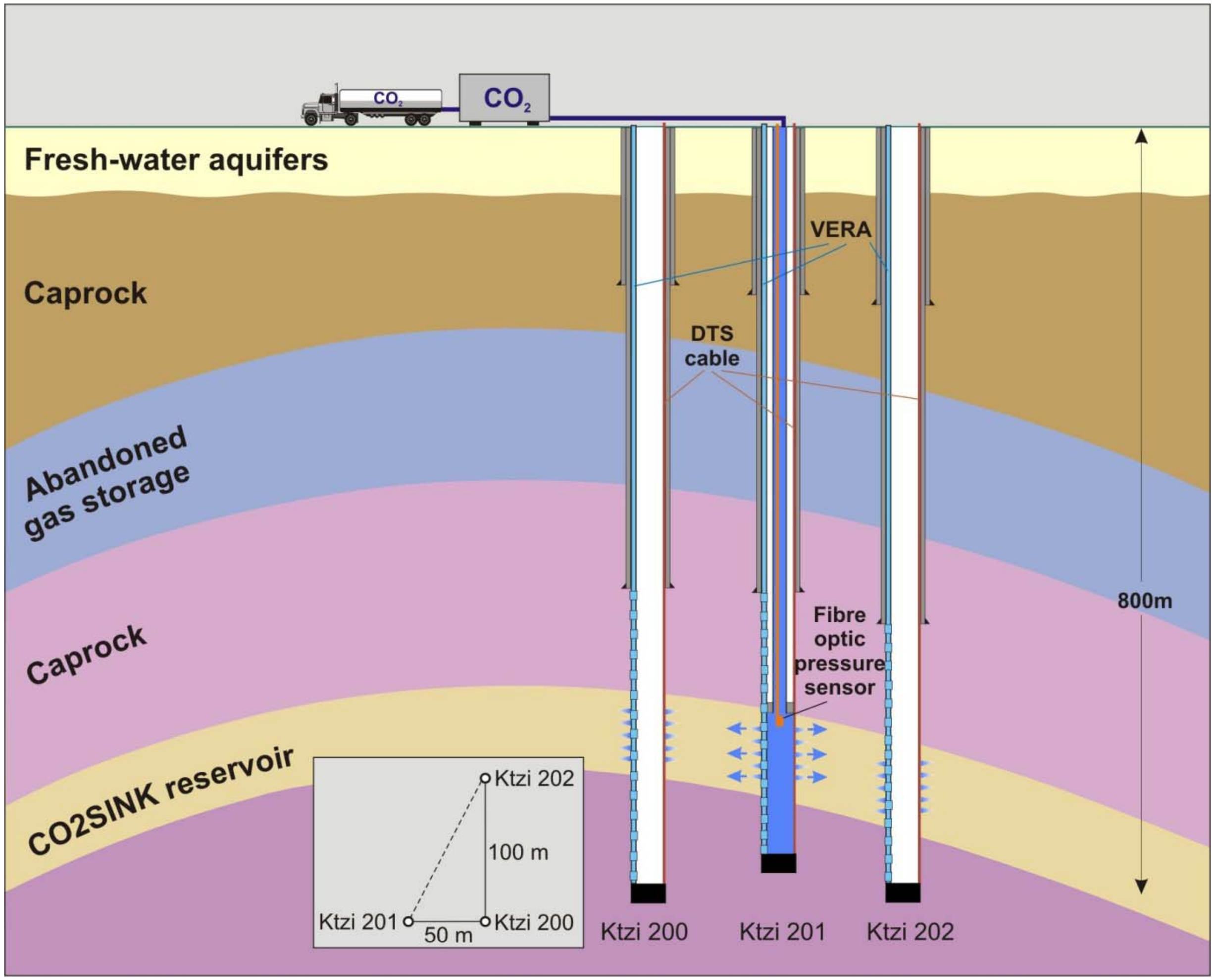
DTS downhole cable design



AFL Telecommunications

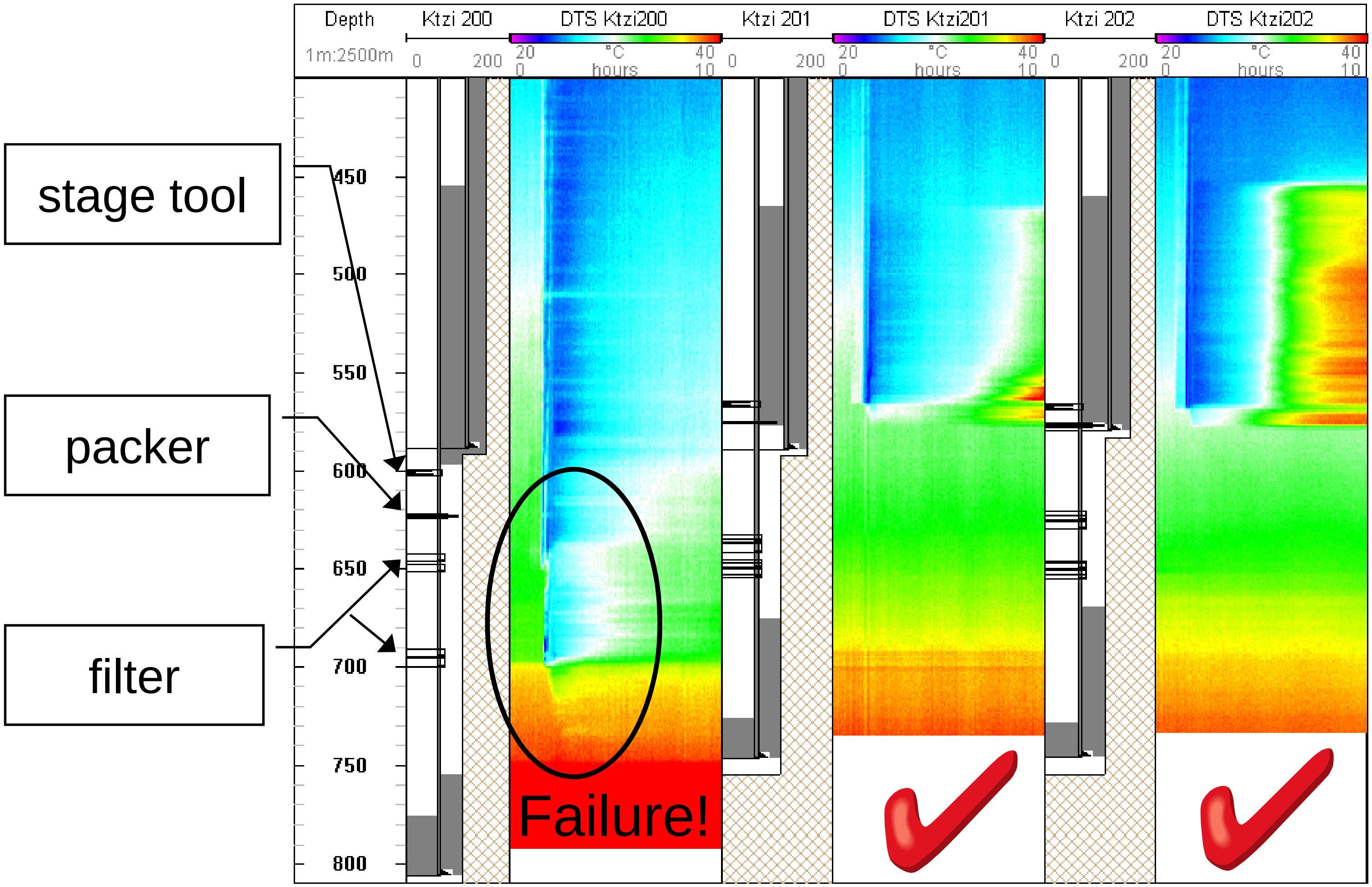
150 °C, 20.000 psi
Tube: 316SS / Incoloy 825
OD 6.35 mm (1/4“)

Ketzin: Permanent downhole sensors



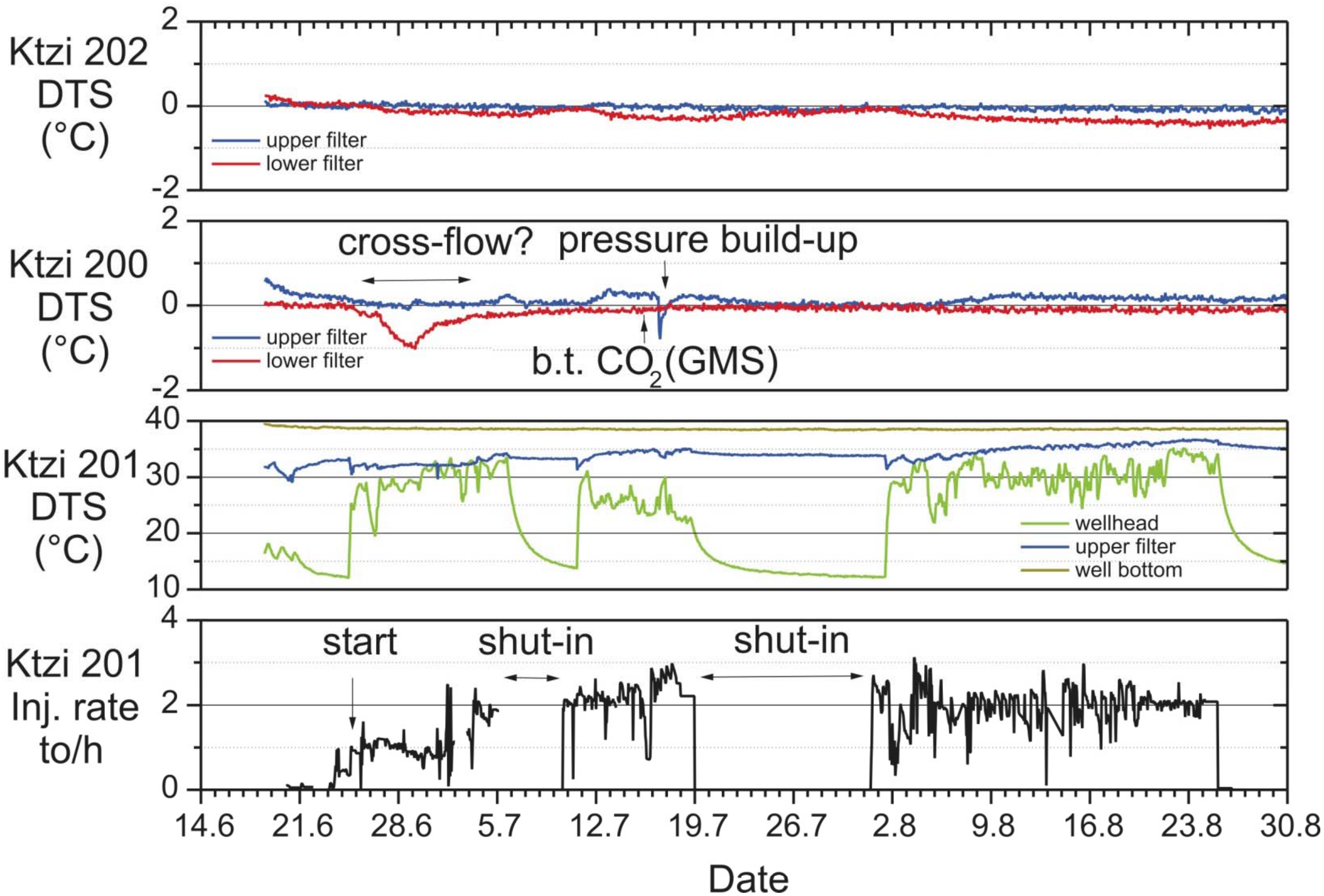
Permanent installation of sensor cables

DTS-Monitoring: Well cementing



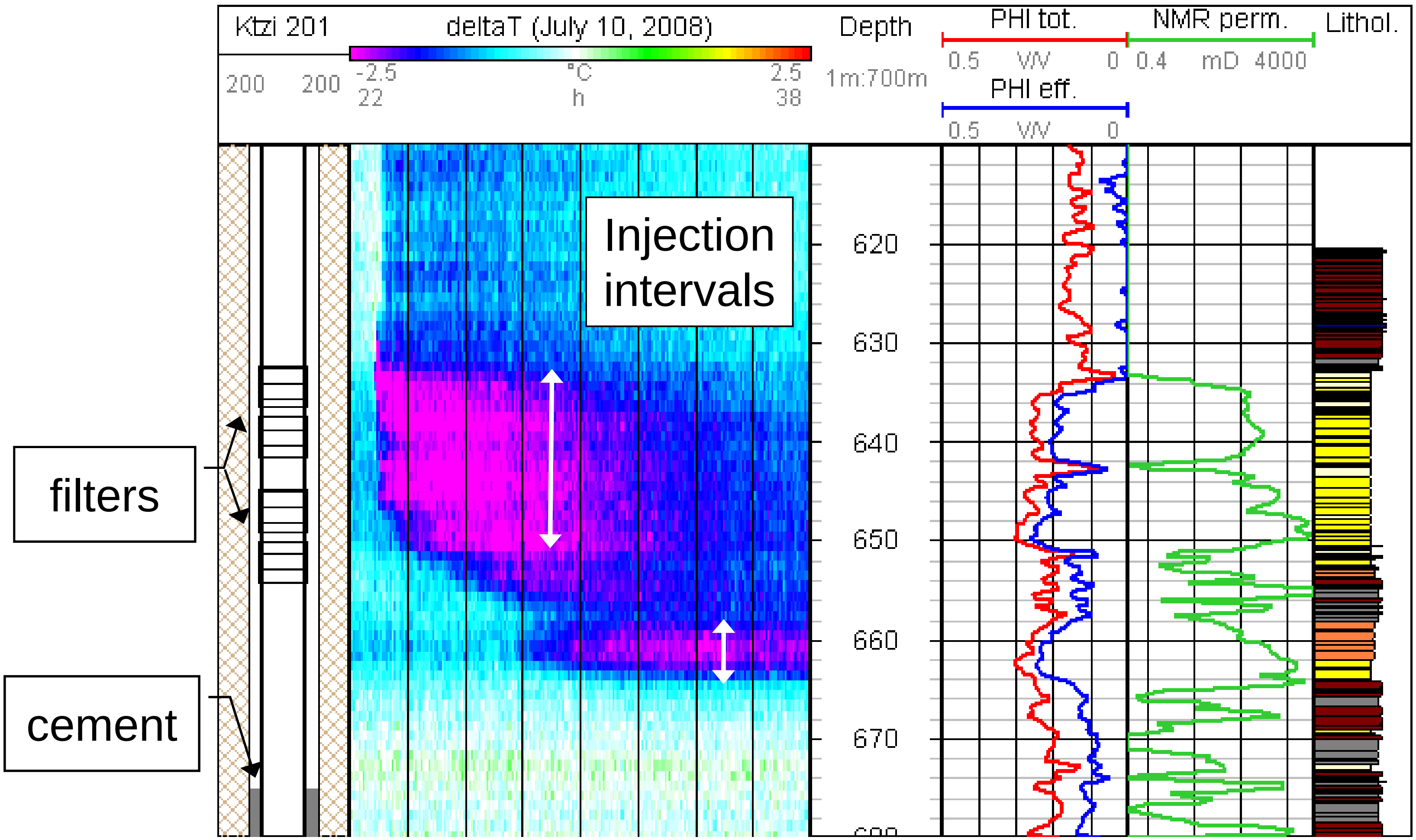
Temp. increase: setting of cement (heat of hydration)

DTS-Monitoring during injection

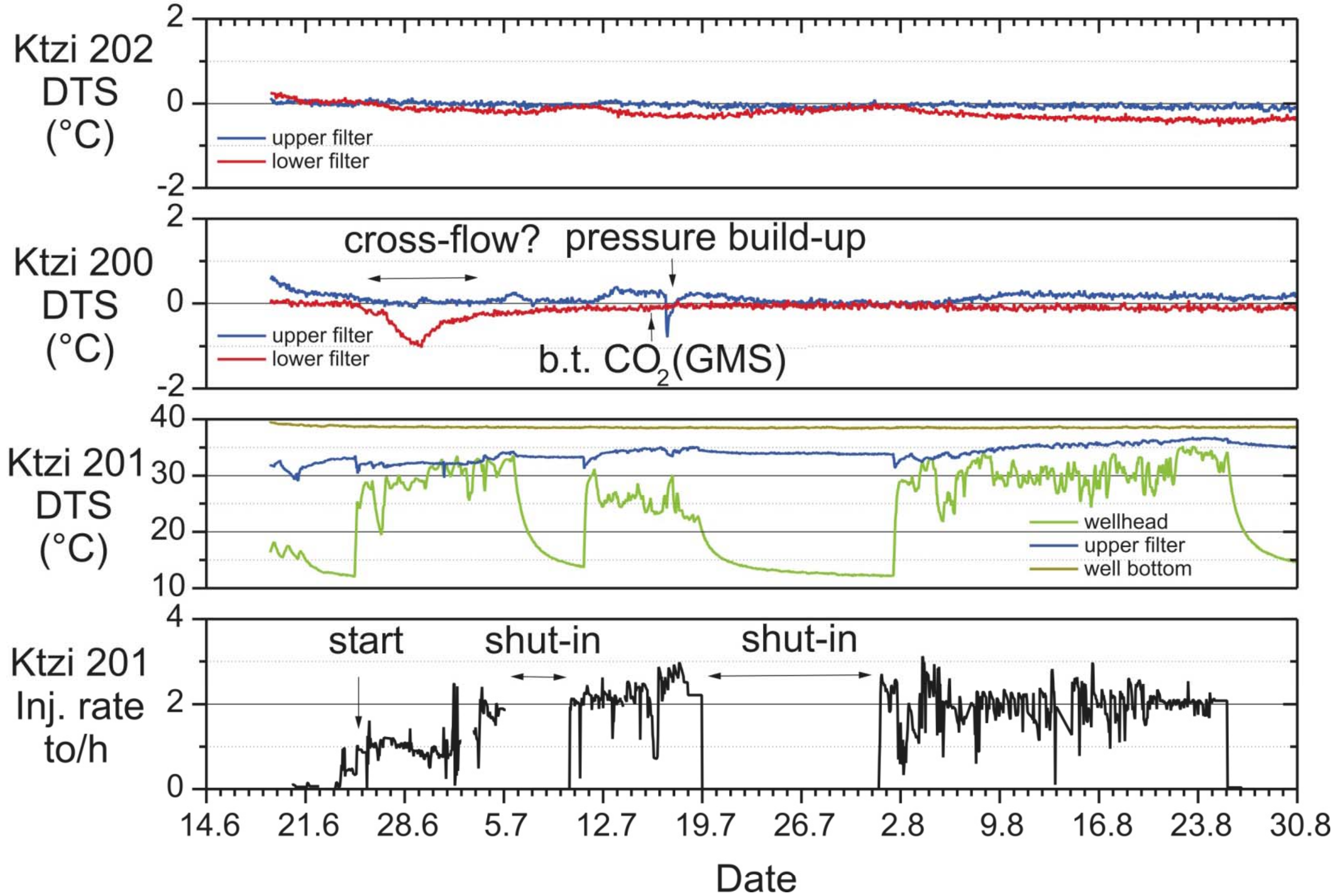


Injection temperatures (upper filter): +/- 5 °C from formation temperature

Temperature changes injection well



DTS-Monitoring during injection



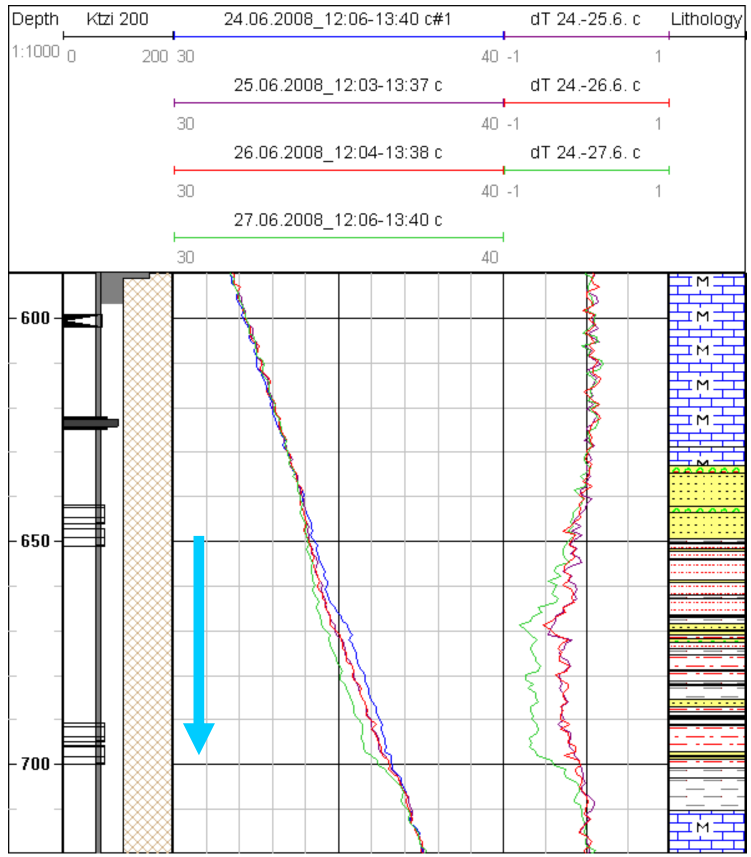
Minor variations (~0.5 °C)

Distinct anomalies (~1.5 °C)

Injection temperatures (upper filter): +/- 5 °C from formation temperature

Temperature profiles obs. well (Ktzi200)

Anomaly at lower filter between start of injection and b.t. of CO2



down/cross-flow

Reference points time-series plots:

Upper filter

Lower filter

Temperature and fluid density Ktzi200

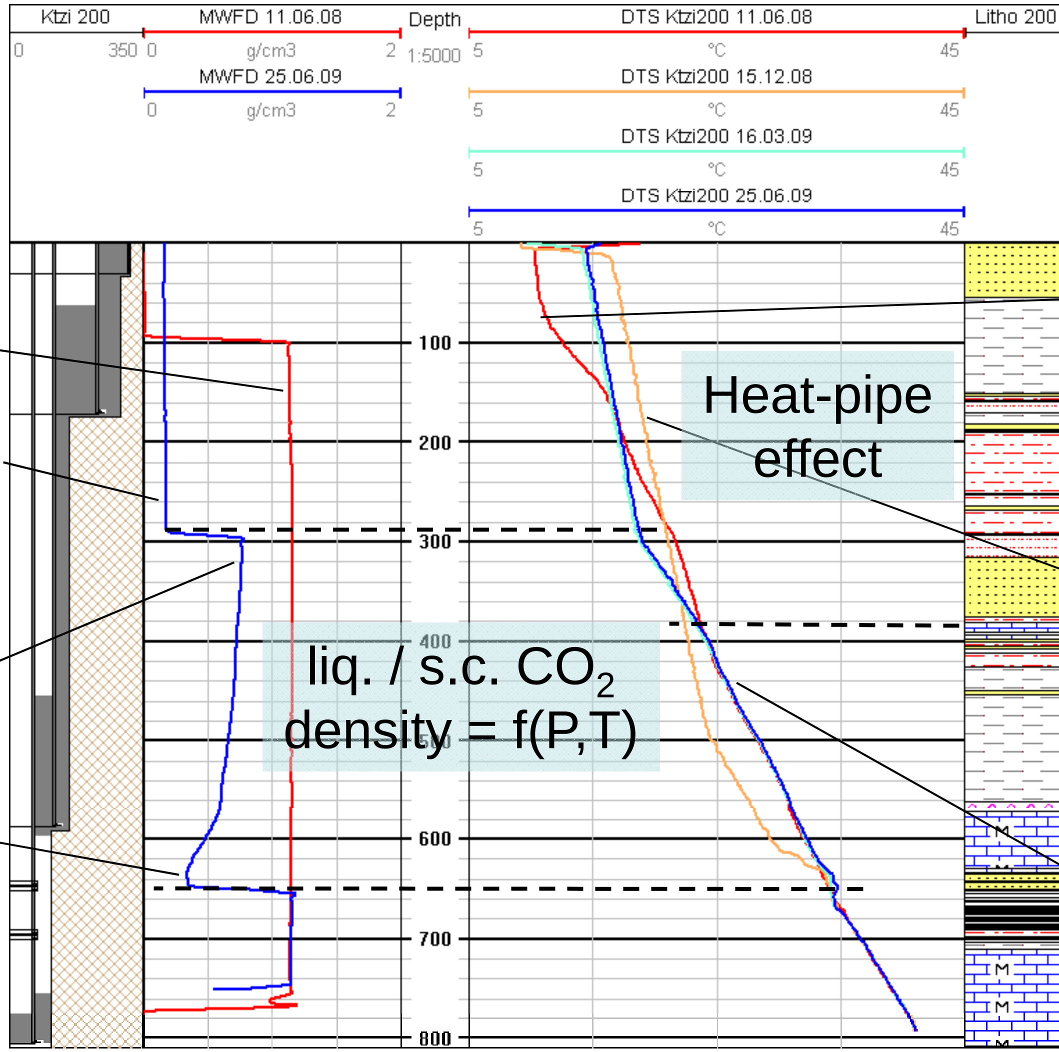
Fluid density:

1.14 (brine)

0.17 (CO_2, gas)

0.81 (CO_2, liq.)

0.34 (CO_2, s.c.)



Temperature:

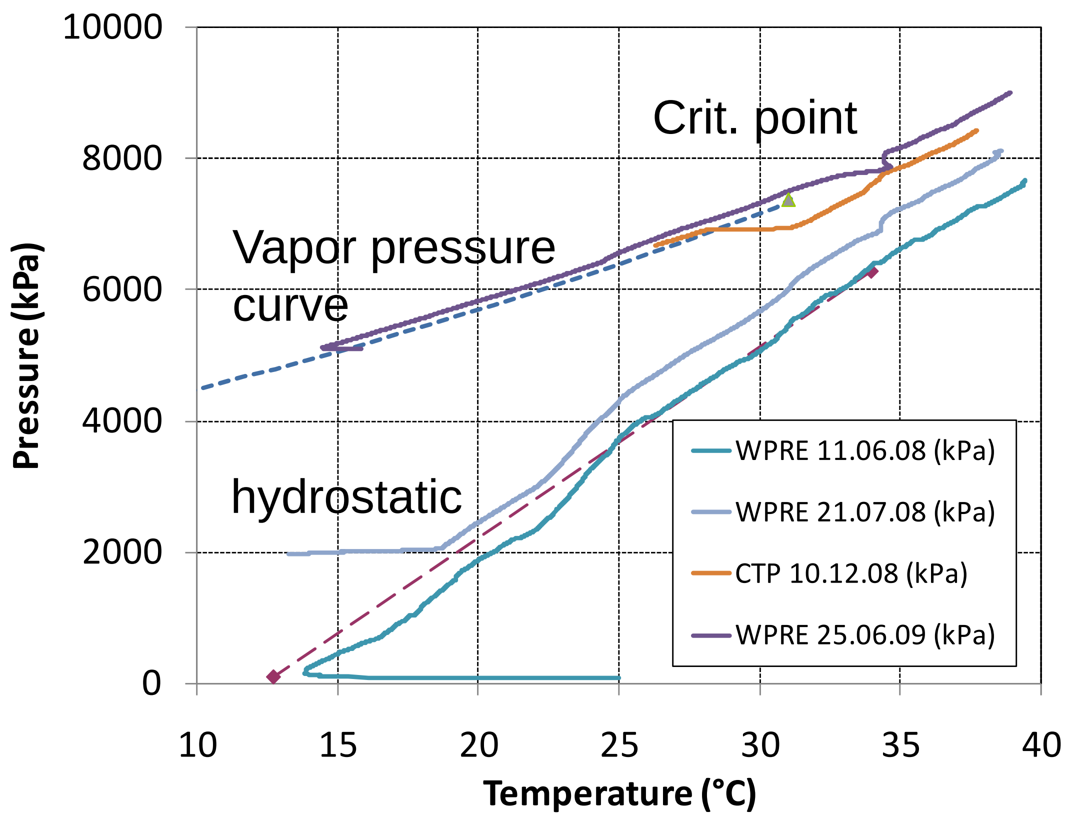
Baseline (before injection)

Anomaly (12/08) Successive increase at top, decrease at bottom

Equilibrium (after 3/09)

Camera inspection Ktzi202: 300m depth

Pressure – temperature diagram Ktzi 200



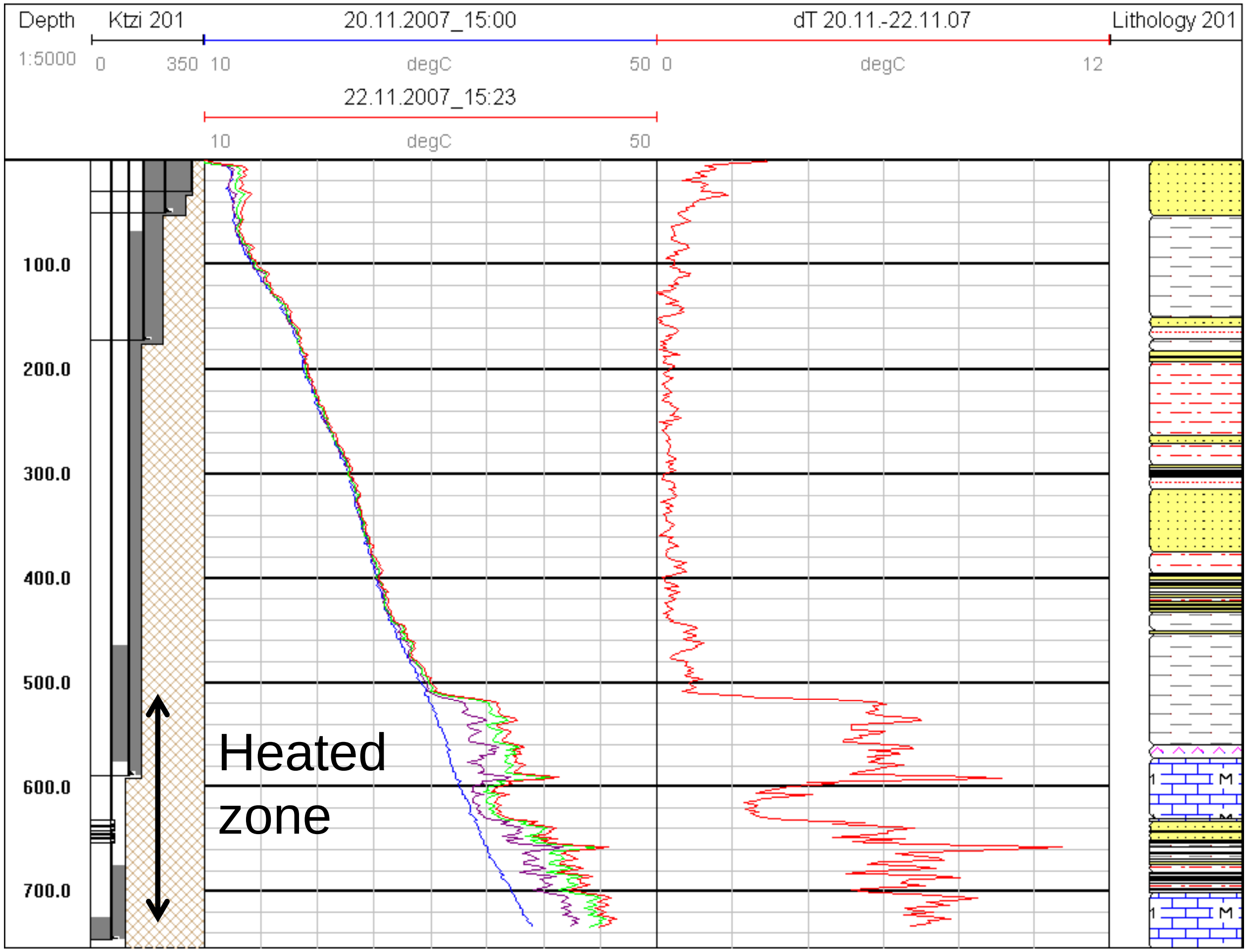
June 2009 measurement:

- < 400m: equal/close to vapor pressure curve for CO_2 (2-phase conditions)
- > 400m: liquid and supercritical CO_2
- Implications: difficult to predict downhole pressure, P/T conditions fixed to vapor pressure curve (2-phase region)

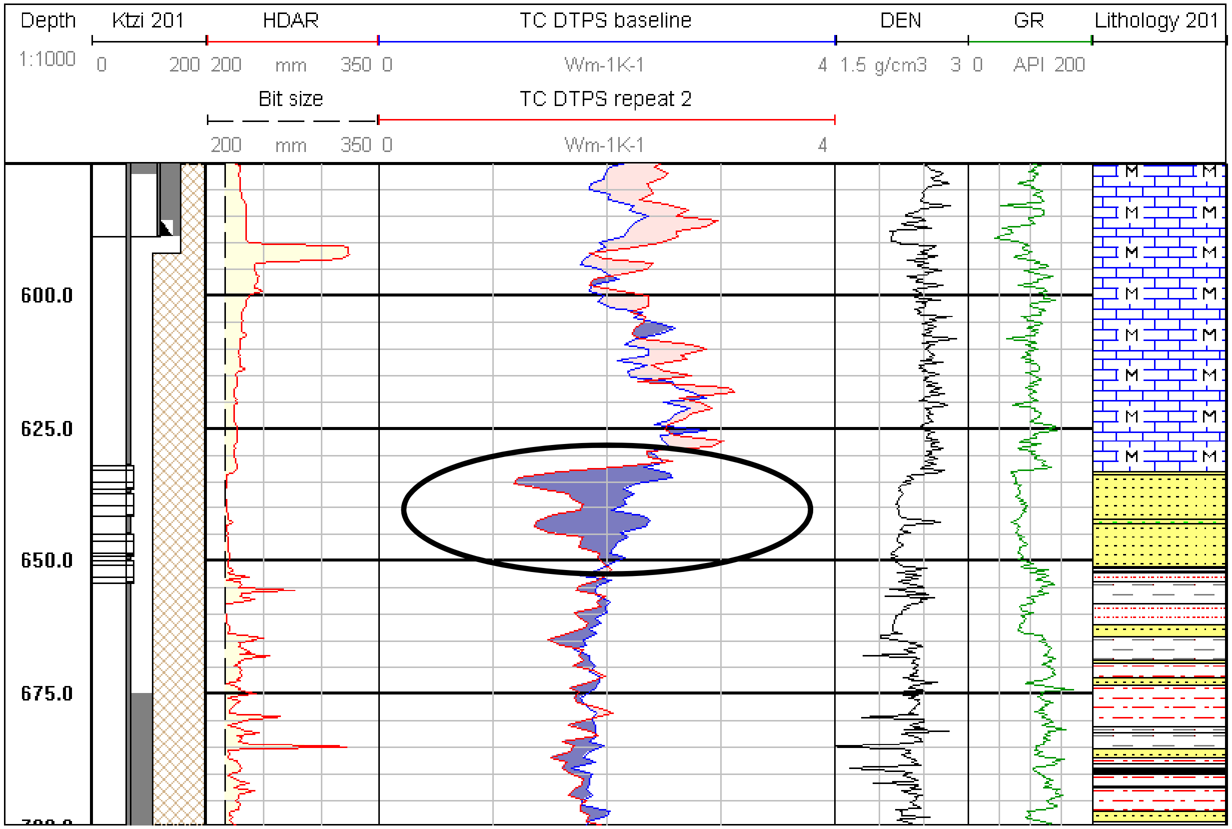
Heat-pulse measurement

Active heating of borehole with electical heater cable, temperature monitoring with DTS

Numerical inversion: in-situ thermal conductivity (collaboration with B. Freifeld, LBNL)



Change in thermal conductivity after start of CO_2 injection



Blue: baseline

Red: repeat after injection of 1.700 t CO_2

Purple: decrease due to replacement of brine by CO_2

Distinct zone with decrease in thermal conductivity: main zone of CO_2 injection. (collaboration with B. Freifeld, LBNL)

Summary

- Borehole temperature monitoring using DTS:
  - Advantages: continuous monitoring of downhole conditions and processes along entire well, no downhole electronics
  - Drawbacks: lower accuracy, higher drift of data over time
- Temperature: good indicator for flow processes inside well
- DTS monitoring during cementing: operations, setting of cement
- DTS monitoring during CO_2 injection:
  - Detection of behind-casing flow using temperature
  - 2-phase conditions: Temp. fixed to vapor pressure curve
- Heat-pulse measurements: changes of thermal conductivity

Outlook

- DTS and heater cables:
  - Hybrid wireline cables for temporary / retrievable deployment
- Borehole integrity:
  - Methods for on-line analysis of DTS data to derive information about cement quality, flow (leakage) rates
  - Enhanced detection of flow / advective transport of heat using heat pulse method

Acknowledgements:
DTS monitoring team GFZ (J. Schrötter, M. Poser, C. Cunow, T. Reinsch), B.M. Freifeld (LBNL), Schlumberger Carbon Services, VNG Verbundnetz Gas AG, B. Prevedel, C. Schmidt-Hattenberger (GFZ), H. Schütt (GFZ/StatoilHydro).

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Thank you for your attention!