3rd Wellbore Integrity Workshop

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INTERNATIONAL ENERGY AGENCY

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ACKNOWLEDGEMENTS AND CITATIONS

The IEA Greenhouse Gas R&D Programme 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 the IEA Greenhouse Gas R&D Programme as a record of the events of that workshop.

The third international research network on Well Bore Integrity was organised by IEA Greenhouse Gas R&D Programme in co-operation with BP and Los Alamos National Laboratory. The organisers acknowledge the financial support provided by EPRI for this meeting and the hospitality provided by the hosts La Fonda Hotel, Santa Fe.

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

Charles Christopher, BP (Chairman)
John Gale, IEA Greenhouse Gas R&D Programme (Co-chair)
Idar Akervoll, SINTEF
Bill Carey, LANL
Mike Celia, Princeton University
Rich Chalaturnyk, University of Alberta
Daryl Kellingray, BP
Toby Aiken, IEA Greenhouse Gas R&D Programme

The report should be cited in literature as follows:

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Further information on the network activities or copies of the report can be obtained by contacting the IEA GHG Programme at:

IEA Greenhouse R&D Programme, Orchard Business Centre,
Stoke Orchard, Cheltenham Glos. GL52 7RZ. UK
Tel: +44 1242 680753 Fax: +44 1242 680758
E-mail: mail@ieaghg.org
www.ieagreen.org.uk

Summary Report of 3rd Well Bore Integrity Network Meeting

Date: 12 – 13 March 2007

La Fonda Hotel,

Santa Fe,

New Mexico, USA

Organised by IEA GHG and Los Alamos National Laboratory, with the support of EPRI

THIRD WORKSHOP OF THE INTERNATIONAL RESEARCH NETWORK ON WELL BORE INTEGRITY

Executive Summary

The third meeting of the Well Bore Integrity Research Network was held in Santa Fe, New Mexico, USA in March 2007. For the third year in a row, the meeting was well attended by many areas of industry, research and those involved in regulatory processes.

A variety of presentations were given in 4 sessions covering field studies and surveys of wellbore performance and reliability, experimental observations of the interactions between CO_2 and cement, numerical modelling and experiments, and policy & regulations. The decision was made in advance to hold facilitated discussion sessions rather than smaller break-out groups and these proved to be very successful, with some very interesting and insightful observations and debates between those with different views and backgrounds.

The general consensus and tone of the meeting was that the issue of well bore integrity is still very topical and will remain so for the foreseeable future. Several reports and presentations dealt with the issues associated with identifying leakage and the factors that can affect or lead to leakage from well bores. The papers presented compared results from experiments in the field with results gleaned from laboratory experiments, and it was felt that significant advances had been made over the past year in terms of the depth of understanding and knowledge gained.

Another group of presentations covered the developments and evolution within the regulatory environment relating to CCS activities. Several presentations were given on this subject, and it was made clear that regulators are interested in setting out a framework for CCS that is clear and that this framework will be aimed at controlling activities rather than curtailing them.

Site selection, with specific regard to the area of identification of existing wellbores, generated a great deal of interest, and the question of what should be done with existing wells when they are within the spatial area defined by a potential storage project was debated at length. It seems that there is no set practice to follow with regard to re-completion of old wells deemed to be a high risk, and this is an area that requires more research in the future. Abandonment methods applied to historical wells differ from location to location; as do opinions as to whether any leakage can be defined as acceptable. This seems to pose the greatest problem for regions like Alberta in Canada and Texas in the USA where there are large numbers of old wells. It was noted that whereas Alberta has a large repository of detailed information on the historical wells within their province, the state of Texas has up to 1 million old wellbores, with varying amounts of information on the locations, depths and construction / abandonment methods used.

Various experimental results were presented on studies of interactions between wellbore cements and CO_2. Again there were some conflicting results between field experiments and lab based experiments regarding cement degradation, and it is hoped that these discrepancies will fuel further work. There is an altered focus for the coming years work, and more field work and pilot / demonstration scale projects are needed in order to take the next steps towards making CCS a viable, accepted option for mitigation of anthropogenic CO_2 emissions.

Contents

1. Introduction

At the end of the second meeting of the international wellbore integrity network, it was concluded that the task ahead was one of investigating and minimising the concerns of wellbore leakage, and addressing the issues of risk management and reduction. Regulators need to be included in the establishment of guidelines and site selection criteria, to ensure that regulations and common practices are complimentary, without entailing excessive cost implications for operators.

Much investigative and laboratory based modelling work has been carried out since the last meeting on the interactions between injected CO_2, wellbore cement and the caprock interfaces, and many of these results were presented in this, the third workshop meeting of the research network.

The second meeting identified the status of what is and what isn't understood regarding wellbore integrity and it is hoped that this meeting will expand on what we understand and remove some of the uncertainty surrounding those areas which were identified as requiring further research work.

The main issues highlighted for further research work at the end of the second meeting were:

- Well abandonment practices for long term CO_2 containment.
- Well monitoring procedures.
- Results from field experiments.

The primary conclusions derived from the meeting were that:

- There is a problem with wellbore integrity in existing wells associated with oil and gas fields all around the world, and the main cause of this appears to be poor or inconsistent cementing practices.
- Cement can degrade in the presence of CO_2 but the degree of degradation and the specific chemical and physical process present appear to have dissimilar results in the laboratory to what has been observed in the field. More extensive work both in the field, and in the laboratory is needed to determine a correlation between the two, or explain the differences observed.
- Along with cement corrosion, the corrosion suffered by steel casings should not be overlooked as a potential source of leakage, and this should be addressed by improved well completion practices, or removing casings and replacing with cement.
- New CO_2 resistant cements are becoming available, and although the costs appear to be an issue, there is every chance that these may provide a much needed improvement in sealing properties within the wellbore environment, so further experimental work is required to determine the benefits that can be obtained from the use of these CO_2 resistant cements.

The international network continues in its aim to developing a greater understanding of the issues relevant to wellbore integrity and the specific aims of the third meeting are outlined in the next section.

2. Aims & Objectives of the 3rd Workshop

As the international research network on wellbore integrity enters the third year of its proposed five year tenure, the principal aims of the network remain unchanged;

- To provide confidence to all stakeholders that the mechanisms involved with maintaining the integrity of wellbores is understood.
- That the safety of storage, specifically in relation to wellbores, can be ensured because the risks can be identified and minimised.
- That wellbores can be monitored for early signs of leakage, and remediated as necessary.

The third meeting specifically aims to demonstrate that research has helped to move the technology towards widespread implementation by identifying and understanding the technical barriers encountered while working to address and neutralise these barriers, and also to provide a platform for dissemination of results, information and observations from field and laboratory experiments / measurements. The meeting will also aim to determine what next steps are needed in order to progress the technology even further, into the arena of large-scale demonstration projects.

3. Workshop Attendees

The meeting was attended by 63 delegates from 8 countries (Appendix 1). The delegates represented Australian and North American regulators, international industrial operators and geological researchers from Australia, Europe and North America.

4. Workshop Programme

The programme and agenda for the meeting are presented in Table 1. The Monitoring Network meeting was divided into a series of sessions, which focussed on specific topics within the area of monitoring and verification with discussion sessions held after each technical session:

Table 1: Workshop Programme

Day 1 - 12th March	
Session 1 - Introduction	
08.30 to 08.45	Welcome and, fire briefing/safety issues; Charles Christopher, BP; John Gale IEA GHG; Bill Carey LANL.
08.45 to 09.00	LANL Welcome Mary Neu and George Guthrie, LANL
Session 2 - Field Studies/Surveys of wellbore Performance and Reliability	
09.00 to 09.25	Factors Affecting Or Indicating Potential Wellbore Leakage: Stefan Bachu and Theresa Watson; EUB and Watson & Associates.
09.25 to 09.50	A Comprehensive Wellbore Integrity Program: Charles Christopher; BP
09.50 to 10.15	Analysis of Abandoned Well Integrity at a Potential CO_2 Storage Site: Frans Mulders; TNO
10.15 to 10.40 Break	
10.40 to 11.05	Role of Permanent Downhole Integrated Instrumentation Systems in Assessing Wellbore Performance - Penn West CO2-EOR Monitoring Project: Rick Chalaturnyk; University of Alberta
11.05 to 12.05	**Facilitated Discussion** Theme: What conclusions can we draw today about the viability of CO2 sequestration in reservoirs with numerous wells?
12.05 to 13.30 Lunch	
Session 3 - Cement CO2 Interaction Experiments and Observations	
13.30 to 13.55	Degradation of Wellbore Cements: Results of Long-Term Experiments and Effect of Additives: Barbara Kutchko and Brian Strazisar; NETL
13.55 to 14.20	Core-Flood and Batch Experiments on Carbon Casing-Cement-Shale Composites: Marcus Wigand; LANL
14.20 to 14.55	CO_2 Flooding Applications for Cores and Cement/Casing Composites: Bob Svec and Reid Grigg; New Mexico Tech.
14.55 to 15.20 Break	
15.20 to 15.45	Carbonation of Concrete Structures: Niels Thaulow; R.J. Lee Group.
15.45 to 16.05	Behaviour of Portland Cement in CO_2 Rich Water/Brine. Implications on Wellbore Integrity for CO_2 Storage: Veronique Bartlet-Gouedard; Schlumberger
16.05 to 17.05	**Facilitated Discussion** Theme: Can experiments provide critical parameters for modeling and actually demonstrate the viability of wellbore seals?
18.00 to 19.00	Reception and Poster Session: LA Fonda Hotel

Table 1: Workshop Programme (Cont'd)

Day 2- 13th March	
Session 4- Numerical Modeling & Experiments of the Near- and Far-Field Wellbore Environment	
08.30 to 08.55	Well Cement Ageing in Various H_2S-CO_2 Fluids at High Pressure and High Temperature: Experiments and Modelling: Nicolas Jacquement; French Geological Survey.
08.55 to 09.20	Simulation of cement reactivity with CO2 in the wellbore environments: Peter Lichtner/ Bill Carey/ Chuan Lu; LANL
09.20 to 09.55	Measuring Effective Wellbore Permeability: A Numerical Analysis of a Field Pressure Test: Sarah Gasda; Princeton University.
09.55 to 10.20 Break	
10.20 to 10.55	Assessing Wellbore Leakage and its Potential Impact Through CO_2-PENS, a Systems Level Model: Rajesh Pawar; LANL
10.55 to 12.00	**Facilitated Discussion** Theme: How can numerical models of wellbore performance be validated?
12.00 to 13.30 Lunch	
Session 5- Policies, Regulations and Best Practices.	
13.30 to 13.55	API philosophy and Approach to Wellbore Integrity: Ron Sweatman; Halliburton.
13.55 to 14.20	A Review of Injection Well Mechanical Integrity Testing Data and implications for Geosequestration: Jonathan Koplos; Cadmus Group.
14.20 to 14.55	An Overview of Alberta Regulations, Past and Present- Ensuring Wellbore Integrity: Theresa Watson; Watson & Associates.
14.55 to 15.20 Break	
15.20 to 16.20	**Facilitated Discussion** Theme: How should the performance of new and old wells be validated in a regulatory environment?
Session 6 - Summary, Discussion and Close	
16.20 to 17.00	**Chair: Charles Christopher; BP** Concluding Discussions, next steps and proposals for next meeting.
Close Day 2	

5. Technical Presentations

5.1 Field Studies / Surveys of Wellbore Performance and Reliability

The presentations were held in 4 sessions, each covering a different broad topic, and with a related facilitated discussion. The results from the presentations are below, and details of the facilitated discussion sessions can be found in section 6.

5.1.1 Stefan Bachu, EUB & Theresa Watson, Watson & Associates; Factors Affecting or Indicating Potential Well Bore Leakage.

Stefan Bachu gave a presentation addressing the factors and indicators of well bore leakage. He opened with the question of whether old or new wells posed the greatest potential for leakage.

As an example, it was stated that in the Alberta region, in 2006 there were 116,550 abandoned wells[1] dating as far back as 1893. Note; Alberta is still drilling new wells at a rate of about 20,000 per year. A lot of old wells are showing evidence of leakage at surface in the form of sustained casing pressure or gas in soils adjacent to the wells. Fortunately, there exists a large repository of information and data on many of these wells covering a wide range of information including factors such as location, depth, methods and materials used in construction, cement data and any deviation of the wells. The deviation of the wells can have a great impact on the cement as cement sets differently in deviated wells than in vertically true wells.

Assessment of the data combined with field studies and research allows a ranking of factors and their impacts on integrity to be performed. This exercise leads to the formation of the following table.

Factor	**Level of Affect**		
	Major	Minor	Minimal / None
Geographic area (test area)	√		
Well deviation	√		
Well type (drilled & abandoned, cased & abandoned)	√		
Abandonment method (bridge plugs, welded caps)	√		
Economic activity (efficiency of abandonment workforce)	√		
Un-cemented casing / hole annulus	√		
Licensee		√	
Depth of surface casing		√	
Total depth		√	
Well density		√	
Topography		√	
Well age			√
Well operational mode (production, injection, disposal)			√
Completion interval			√
H_2S / CO_2 presence			√

[1] Figure as at the end of 2006

Analysis of over 10,000 metres in 142 wells shows good cementing practices greatly reduced the occurrence and severity of corrosion as ⅔ of leaks occurred where no cement was present compared with 5% where cement quality was categorised as excellent. Another support for this was the analysis on 64 wells that showed that over 80% of instances of sustained casing pressure (SCP)[2] and gas migration occurred above the cement top.

Stefan concluded that mechanical factors will have the greatest impact on well leakage and good cementing practices and well-enforced regulations are likely to be instrumental in controlling and detecting well leakage.

5.1.2 Charles Christopher, BP; A Comprehensive Wellbore Integrity Programme,

Charles Christopher gave a brief summary of the requirements of a CO_2 Wellbore Integrity Programme which included field data and references to an ongoing project, although no results or conclusions were presented from this project as it is incomplete, the preliminary results therefore still require careful evaluation and confirmation before being disseminated.

Despite this, there were three main points presented as possible areas for future development and research:

- The kinetics tests carried out within the laboratory environment did not reciprocate and match the results gleaned from the field experiments. This suggests that more extensive field and laboratory work is required to determine the consequences and repercussions of this if the results are replicated in subsequent experiments.

- A cement core taken from the well covering a depth to include both the cap rock and cemented section shows signs of very good bonding between the sections. It was also noted that the cement section appeared to be porous and is being analysed in more detail to determine this.

- It can be concluded that a comprehensive wellbore integrity programme must include the regulators involved in a storage project, as well as the surrounding community and the project operators. As much information as is possible should be assimilated and disseminated at an early stage to minimise the need for repeated requests for information.

Charles finished by saying that there were some very interesting and promising results coming from the project, but until full evaluation of results have been carried out no figures and data will be published yet.

[2] Also referred to as Surface Casing Vent Flow - SCVF

5.1.3 Frans Mulders, TNO; Analysis of Abandoned Well Integrity at a Potential CO_2 Storage Site.

Frans gave a comprehensive overview of a case study focussing on a site being considered for CO_2 storage in the Netherlands. The site included within its boundaries a number of producing and abandoned well bores used for the purpose of oil and gas exploration and production. The study addressed the possible mechanisms and pathways that could facilitate leakage, and also how such projects would be affected by the stringent standards laid out under Dutch mining law.

The study addressed the question of how fast and how far could CO_2 leak up a well, and in answering this, a thorough understanding of the wells present and their geometry and construction materials and methods was required. Analysis of records and abandonment data revealed that the wells in this field were sunk through a stacked reservoir comprising of one oil and two gas stacks, the reservoir targeted for injection was the shallower, depleted gas stack.

All the wells had been abandoned according to the standards detailed within Dutch mining law, and it was highlighted that these regulations call for much higher standards than are used in some other regions, for example where a bridge plug is used in well abandonment, application of Dutch mining law results in a plug three times the length of a similar plug installed under US conditions for example.

The abandoned wells were examined for signs of corrosion (indicating CO_2 leakage) and the Primary Cement Sheath (PCS) and bridge plug were analysed to determine the presence and extent of corrosion. It was also noted that some wells had no PCS at the level of CO_2 injection, creating a possible CO_2 leakage pathway upwards through the well.

The study also took some results from a study by Bartlet-Gouedard et al (2006) on the chemical degradation of Portland cement and applied the results to the cement in the wells and extrapolated that the bridge plugs could, under ideal conditions, withstand the presence of CO_2 for between 60,000 to 17 million years.

Frans concluded that diffusion doesn't seem to be a cause for concern, moreover corrosion of the PCS and well casing were the areas shown to hold the greatest potential leakage opportunity. Although it was difficult to make an accurate assessment, it was concluded that the cement may in fact remain structurally sound for somewhere in the order of decades under the conditions prevailing in the area of study.

On this site, it was determined that stress and deformations in the surrounding reservoirs were insufficient in strength and magnitude to seriously damage the wells, but may enhance and promote the corrosion rates encountered by the PCS and well casing. This was a contributing factor to the ultimate decision of the operators not to continue with the project on this site as the risk of leakage from the storage area was considered too high.

Q. Why is rehabilitation of poor condition wells not considered feasible if the site has a good potential for CCS?
A. The decision was more complicated on this site as some wells were obstructed by buildings, making them inaccessible, and too great a risk for CCS activities.

Q. Was the biggest problem encountered the lack of cementing at the level of CO_2 injection in some of the old wells?
A. Operators decided that the site was unsuitable due to its proximity to centres of population, the high risk of leaks from some of the poorer condition wells, and the overriding factor that the project being a pilot project in the Netherlands posed too great a risk.

Q. Why not use the oil stack for the injection process as it forms the best, most suitable feature in the formation?
A. There were injectivity problems with the lower oil stack, and there remain two production wells within that stack and the operators didn't want to jeopardise the gas production operation.

5.1.4 Rich Chalaturnyk, University of Alberta; Role of Permanent Downhole Integrated Instrumentation Systems in Assessing Wellbore Performance – Penn West CO_2-EOR Monitoring Project.

Rich Chalaturnyk presented a technical summary of a system of permanent downhole monitoring. A variety of gauges were used in the case study example of the Penn West project, and these gauges measured variables such as pressure and temperature for both bottom hole and the surrounding reservoir. This data was used in a 'casing conveyed system' together with fully integrated geophones and fluid sampling equipment.

The use of such extensive, integrated monitoring equipment and methods gave a very clear picture of what was happening both at the bottom of the well, and in the surrounding reservoir structure. This picture showed that the well in question had been poorly cemented, but all the gauges survived the installation process, and were functioning correctly and communicating data to the surface. This communication enabled detection of CO_2 ingress into the well annulus, and the decision was taken to 'kill' the well by using a tubing punch to punch a hole in the tube, and circulate brine throughout the well. Unfortunately this process damaged the gauges and no further usable information was obtained from them.

Rich concluded that this demonstrated the advantages of an integrated system of well bore monitoring, and the detailed graphical analysis that can be constructed from multiple, complimentary data sets. He also reported that the integrated approach to data verification is critical for creating accurate modelling of well bore integrity.

5.2 Cement – CO_2 Interaction Experiments and Observations

5.2.1 Brian Strazisar, NETL; Degradation of Wellbore Cements: Results of Long-Term Experiments and Effect of Additives.

Brian presented a set of results from a 1 year study on the effects of additives on cement degradation. Although a short time scale, the results gleaned from the laboratory experiments were of a good quality and allowed considerable advances in knowledge to be made. The experiments were also carried out on a field sample supplied by LANL from the SACROC site, and the somewhat surprising results showed that the laboratory samples matched with some degree of closeness the results from the field sample.

The images included in the presentation showed clearly the differing zones of reactivity through the samples from unaltered cement in the centre through to the completely reacted and carbonated cement on the outer edges of the samples. The experimental methods used allowed the researchers to demonstrate that the reactions that occur in the aqueous phase also occur in the headspace, although the speed of the reactions are quite different, with the reactions in the aqueous phase occurring at a much faster rate. It should be noted that evidence showed that the rate of reaction slowed over time, with a marked deceleration being observed through the course of the experiments.

The experiments used a variety of additives to establish the effects of using additives with the cement, and without exception, the cement with additives all degraded at a much more rapid pace than those without additives. Although this goes somewhat against the accepted knowledge, all the samples showed the same pattern when additives were introduced to the composition.

5.2.2 Marcus Wigand, LANL; Core-Flood and Batch Experiments on Carbon Casing-Cement-Shale Composites.

Marcus' presentation disseminated the results from a series of experiments undertaken by LANL investigating the effects and interactions between CO_2 and various components of the well bore installation.

Three main areas of risk were investigated, and these were wellbore flow, interactions between the cement and supercritical gasses or acid gasses, and the interactions between the cement and the brine formation water. The experiment looked at the rates of diffusion and permeability, and found that in all samples, the permeability of the cement reduced over time, which corresponds to the findings from the presentation given by Brian Strazisar of NETL, where a deceleration in the rate of reaction was noted in laboratory and field samples.

The conclusions drawn from this experiment suggest that micro fractures within the interface zone of the cement and cap rock are able to heal over a period of time, which had not previously been demonstrated. This conclusion is given some weight and plausibility due to the collaborative results from the NETL experiments previously discussed.

The analysis of carbonation throughout the cement samples suggest that not every type of Portland cement will suffer complete carbonation in the presence of super critical CO_2 and brine, although it should be noted that during the 172 day course of the experiment, the CO_2

did not penetrate the entire length of the core, so this conclusion may be subject to further analysis following subsequent investigation.

Marcus concluded that the geochemical calculations within the experimental scope show that carbonates are under-saturated if the CO_2 pressure is assumed to be high, and that mineral stabilities are difficult to interpret due to the combination of factors such as high ionic strength, the uncertainty of the degree of equilibrium attained and the extent of exposure to CO_2. All these observations and conclusions can be associated to the lack of significant CO_2 penetration into the cement core, inhibiting the extent of reactions that can subsequently occur.

5.2.3 Bob Svec and Reid Grigg, New Mexico Tech; Core Flooding Applications For Limestone and Cement Composite Cores.

Bob Svec presented the preliminary results and experiences from a series of experiments designed with the objective of performing a comprehensive study on the interactions between co-injected brine and supercritical CO_2 with a composite core consisting of limestone and cement containing a well casing segment. It was hoped that flow through the cement would be constrained to the casing interface zone.

One factor that had to be addressed was how to monitor the flow, and it was decided to use a manganese salt to act as a tracer element which would then aid the identification of any minerals that were deposited during the flooding procedure.

The cement cores were air dried, and this unfortunately resulted in severe cracking before the commencement of the experiment. The crack was sealed with a lead injection procedure, and it was presumed that the pressure from the overburden and the re-introduction of the brine fluid closed the fracture as the core subsequently held pressures of 2000 psi without any indications of flow occurring. This was used as an example of the sensitivity of the cements present to the brine fluids.

The creation of the cores was repeated, and this time they were cured for a period of 30 days in a solution of $Ca(OH)_2$, and this method meant that the cement did not dry in the same manner as before and no fractures formed.

Effluent samples were taken from the brine fluids at increasing time intervals to determine precipitation of minerals and solids. The immediate samples showed a white solid precipitation which was sampled and determined to be calcium carbonate. Subsequent samples produced a precipitation of brown solids which, at the time of presenting, had not been identified.

Bob concluded by expressing the point that the experiment was a work in progress, and the results and conclusions would not be fully released until the project reached its conclusion, but confirmed that the next activities planned are as follows. LANL have the cement section of the core and this will be sectioned and examined under an SEM, and for evidence of the presence and extent of cement carbonation. While LANL perform this, New Mexico Tech will have the limestone section of the core, and this will be sampled, and a wet chemical analysis will be carried out, along with BSEI imaging of the sample. Finally, the effluent brine samples will be analysed for all the major elements in order to gain more of an understanding of the interactions and differences between the two sections.

5.2.4 Niels Thaulow, R. J. Lee Group; Carbonation of Concrete Structures.

Niels Thaulow gave an interesting presentation on the subject of carbonation of various types and ages of concrete, and addressed the question of why some newer concrete structures seem more susceptible to carbonation that some much older structures.

Niels gave examples of 'good' concrete structures as the Hoover Dam, and a 650 year old bridge, while examples of 'bad' concrete structures were given as a rail bridge in Pennsylvania, and a 50 year old bridge, approximately 600 yards from the previously mentioned 650 year old bridge.

Many different factors have an effect on the rate of carbonation in concrete structures, and as they can all occur at the same time, the relative importance depends on the composition of the concrete. The factors generally accepted as having the greatest affect are the porosity of the concrete, the availability of calcium hydroxide, the presence and concentration of CO_2 present, the relative humidity and the ambient temperature where the concrete is installed.

An example was given of the difference the water / cement ratio can have on the depth of carbonation, and a sample of cement with a water cement ratio of 0.45 (relatively low) that was 136 years old showed a carbonation penetration depth of 5 mm, whereas the comparison was a 10 year old sample of concrete, with a relatively high water / cement ratio (0.70) where the carbonation had penetrated to a depth of 50mm – ten times the depth over a much shorter time period.

This difference is due to the increase in porosity encountered with higher water contents, as much of the water in concrete does not react with the cement, and this excess creates capillary porosity throughout the cement. A low water / cement ratio of 0.40 can be shown to have a low capillary porosity of 8% compared to a high water / cement ratio of 0.70 with a capillary porosity of 35%.

The presentation ended by highlighting the importance of getting the composition of cement correct in order to minimise the risks involved with carbonation and deterioration. The composition has a direct influence on the micro-hardness, the tensile and compressive strength, the permeability and porosity and also the resistance of a structure to the strains of repeated freezing and thawing. All of these factors are key in creating a cement that will be hard wearing, resistant to carbonation and the presence of high concentrations of CO_2 such as might be encountered in a well bore in a storage project.

5.2.5 Veronique Bartlet-Gouedard, Schlumberger; Behaviour of Portland Cement in CO_2 Rich Water / Brine, Implications on Wellbore Integrity for CO_2 Storage.

This study was motivated by the high risk posed by the possibility of CO_2 leakage from a storage reservoir, and the methodology was designed to specifically address this and propose a standard CO_2 testing procedure.

For this study, it was determined that wells in depleted oil and gas fields were completed and abandoned using a Portland based cement, so the methodology was designed to determine the affects of salinity and temperature on the presence and rate of degradation in the Portland cement.

In order to store CO_2 in a supercritical state, it must remain within specific environmental limits, and for CO_2 the critical point is at a temperature of 31.6^{o}C and pressure of 73 bars. For this reason, these conditions were replicated within the laboratory procedures to verify the results, and allow transposition of the lab based results to a field situation.

The experiments were carried out in two mediums – Portland cement immersed in water, and in NaCl brine, and there were distinct differences recorded in the results of these two mediums. The sample of Portland cement in water showed a relatively high alteration when compared with the sample immersed in the NaCl. The brine saturated sample shows a much thinner carbonation front, which is even more noticeable in CO_2 saturated brine when compared with wet supercritical CO_2.

It was noted that in the laboratory environment, there was a 10 fold increase in reaction time and results, and the tests carried out at high temperature in pure water show the greatest carbonation of the cement sample. Finally it was noted that regardless of the conditions and formation water composition, the alteration mechanisms observed were similar throughout the experiment, and as a result of this, CCS operators must consider both the chemical and mechanical impacts on cement degradation, and if poor cementing practices are allowed to occur, it can lead to micro-annunlar formation before the injection of CO_2, which in turn will advance the problems encountered at a much faster rate than would be expected following good cementing practices.

5.3 Numerical Modelling & Experiments of the Near and Far Field Wellbore Environment

5.3.1 Nicolas Jacquement, French Geological Society; Well Cement Ageing in Various H_2S-CO_2 Fluids at High Pressure and High Temperature: Experiments and Modelling.

The presentation given on behalf of the French Geological Society outlined the results from modelling experiments performed to determine the changes undergone by cement in terms of mineralogy, texture and porosity under the environmental conditions maintained within the laboratory.

The cement used in the experiments was a Portland class G-HSR with a silica flour additive with a water / cement ratio of 0.55, and it was cured at a pressure of 210 bar at 140^{o}C for 8 days. The cement was then characterised and was found to have an assemblage of 11A Tobermorite and Quartz crystals, and a water porosity value of 0.4.

The cement analysis was undertaken using optical microscopy, scanning electron microscopy, Raman micro-spectroscopy, X-ray diffraction and water porosimetry, and the conditions followed those set out under Total's reservoir specifications.

The experiment used 3 types of fluid environment for comparison and these were a liquid brine, supercritical CO_2, and a two-phase combination liquid brine / supercritical CO_2, and these showed distinct differences in the carbonation front.

The brine sample showed partial carbonation without changing the global mineralogy. A large deposit of calcite developed which blocked further diffusion and progression of the carbonation front. The second sample with supercritical CO_2 showed full carbonation of the cement, with drastic and complete changes to the mineralogy. This is due to the lack of water, which favours the carbonation process and allows optimal conditions for the diffusion of the supercritical CO_2. The third sample (two phase) showed partial carbonation without changes to the mineralogy, but there was a noted intrusion of the supercritical CO_2 into the porous volume of the cement.

The conclusions drawn from this experiment show that the cement mineralogy is influenced primarily by the presence of CO_2 via the carbonation process, but it should be noted that there is also a weak influence by the presence of H_2S. The degree and extent of the carbonation is controlled by the type of fluid contacting the cement, with the maximum carbonation occurring in a dry environment, and liquid water minimising the level observed.

The results of the modelling procedure were then compared with the results from the experiment, and the mineral zonation was reproduced, as was the action of diffusion blocking by the calcite deposit. The significant difference between the modelling and the experimental results was the thickness of the carbonation front, which was 3 times thicker in the modelled results.

5.3.2 Bill Carey, LANL; Simulation of Cement Reactivity with CO_2 in the Wellbore Environment.

Bill presented a presentation which communicated the results of a numerical experiment that had looked at the flow and diffusion activities at the interfaces between the casing, cement and the surrounding shale.

The primary aim of the study was to develop a model that would allow accurate predictions of the long term integrity of the wellbore cement in the presence of CO_2. The subsequent secondary aims were to determine the extent and mode of interaction between the CO_2 and the cement, and develop a system that would model the changes in cement permeability resulting from the reactions with the CO_2.

The experiment carried out a set of 1-D calculations, and these were used to determine the capillary pressures and properties of the cement, shale and reservoir rocks, but they did not provide flow rates or directions. This lack of flow calculations was intended to be remedied by the subsequent 2-D calculations, but there were problems encountered with the set up and boundary conditions experienced with this, and the preliminary results were only obtained for flow, without reaction.

The 1-D graphs reproduced the textures and structures present within the cement / shale, but gave no indication of the origin of the CO_2. Capillary pressures were found to control whether gas-phase CO2 entered the cement. For cement in contact with reservoir rocks, CO2 could only enter cement by diffusion in the aqueous phase. For CO2 in contact with shale caprock, gas-phase CO2 could enter the cement because the capillary pressure properties of cement and shale were sufficiently similar.

Thus differences in capillary pressures can prevent the CO_2 from entering the cement. The SCAROC sample is now about 30 years old and there is still some unaltered cement present. The model suggests that the SACROC cement may have been protected from CO2 by the relatively high capillary pressures in the cement in comparison with the CO2-bearing porous interface between cement and shale.

Bill concluded by stating that increasing capillary pressures will lead to higher ingress of CO_2 into the cement and subsequent carbonation of the cement leading to degradation. Supercritical CO_2 has a low capillary driving force when in contact with cement and therefore capillary driven flow of CO_2 into high quality cement is unlikely. However, poor quality, high-porosity cement may have a weak capillary barrier and be subject to rapid ingress of CO2 and carbonation. These results are similar to the observations made by Niels Thaulow showing the role of porosity (and water/cement ratio) on cement resistance to carbonation.

5.3.3 Sarah Gasda, Princeton University; Measuring Effective Wellbore Permeability: A Numerical Analysis of a Field Pressure Test.

This presentation addressed the question of whether permeability can be accurately modelled. The proposal focussed around designing a simple field test that would enable the determination of wellbore permeability. The test would then be subjected to numerical analysis to determine its feasibility.

The method used would allow accurate estimation for the permeability of both the formation and caprock, allowing the wellbore permeability to be deduced by observing the pressure response. In order to perform this deduction, simulations were used to generate response curves relating pressure to permeability.

Due to the number of wells and potential leakage pathways that could be present in an area under consideration for CO_2 sequestration, the modelling must be of a 'probable' nature rather than a 'definitive' model which would be excessively difficult to design and verify. The theoretical experiment design used in the modelling scenarios included the concept of micro-fracture formation in the formation surrounding the wellbore during the drilling procedure.

The design of the experiment involved increasing the pressures deep in the well and monitoring above the caprock to determine the permeability of the caprock between two given points. This methodology has limitations in the range of detection, as disturbances outside the range of the instrument at either end of the scale (permeable or impermeable) are difficult to detect due to the error margins associated with the measurement instruments. These instrument limits mean that any 'flat' areas of the model graphs are un-measurable as the variation renders the results unsuitable for use.

Other limits imposed by the instruments are that pressure measurements of less than 10^{-3} cannot be determined, and an error of even 1 order of magnitude could produce results which suggest excellent values for well permeability. This would therefore have to be determined in the field by those conducting the storage operation.

The presentation concluded that throughout the industry there is a lack of meaningful data available for well properties, and a simple downhole pressure test can determine the well permeability value at the points critical for safe storage of CO_2. Thorough but simple field experiments are needed in order to establish accurate estimates of CO_2 leakage, and also to reduce uncertainty associated with the current estimates.

5.3.4 Rajesh Pawar, LANL; Assessing Wellbore Leakage and its Potential Impact Through CO_2PENS, a Systems Level Model.

Rajesh gave a thorough presentation covering all aspects and areas of risk associated with CCS, and also the steps necessary to remediate leaks should they occur.

Three definitions of risk were identified and explained, and these were FEPs analysis (features, events and processes), performance assessments (PA), and quantitative risk assessment (QRA). Of these three options, the QRA is by far the most comprehensive as it incorporates reactions to risk identification and suggests mitigation options.

The main focus of the presentation was LANL's CO_2PENS system comprehensively covers all aspects of a QRA, and acts purely on a scientific basis. Included in its structure are subsystems with further integrated models which are adjustable to facilitate the inclusion of models favoured by operators, or site specific requirements and less favourable or suitable models can be removed. It can be used for projects using injection wells only, projects using separate injection and production wells, as well as co-purpose wells used for both injection and production.

The model includes a range of modules that can be included or precluded to suit the purpose, and there is an atmospheric module that allows for the input and adjustment for seasonal variations that can have an impact on CCS operations. The model also predicts the extent and development of the CO_2 plume at different levels. The model is also suitable for site selection as the initial use determines site suitability, and subsequently uses determine the site characterisation.

Although there is a module that measures seepage rates from a storage reservoir, there isn't a module for measuring CO_2 concentrations within the soil, and although the system can predict fluxes, it cannot predict the consequences of flux and seepage on flora and fauna.

The presentation concluded with three main points. Firstly that large scale initialisation of CCS will require a thoroughly robust, long-term approach to performance and risk assessment. Secondly, the CO_2PENS model system had been developed to provide a science based prediction approach to estimate performance of storage reservoirs based on site-specific performance criteria. The third conclusion was more of a question as to whether any persons or organisations within the global storage community were prepared to predict with 100% certainty that there was a 0% chance of a reservoir leaking or failing in some way, and that understanding and effective communication of the impacts of potential leaks would be a key step in achieving this goal.

5.4 Policies, Regulations and Best Practices

5.4.1 Ron Sweatman, Halliburton; API Philosophy and Approach to Wellbore Integrity.

Ron Sweatman gave an overview of the API's approach to wellbore integrity, and explained that all the details are openly available on their website. The API Standards Process is open to access, and all papers are assessed by all, so the process is also consensus based.

The major activities of the API in the CCS field include a project guidance committee, joint conferences with the DOE and two sets of recommended practices – RP90 dealing with Annular Casing Pressure Management, and RP65 dealing with Pressure Containment.

The next document that is being worked on involves casing flows and pressures, and is being composed by a wide range of experts from upstream water specialists to production experts, and the ultimate aim is to produce a comprehensive set of guidelines covering all aspects and areas involved with CCS, and it is planned to include relevant monitoring techniques specific to each sites characteristics.

RP90 was first published in the summer of 2006, and includes recommendations for remediation work and how best to monitor emissions and it also addresses 'acceptable' emissions limits. It outlines guidance to ensure that casing pressure tests do not result in over pressurisation of the casing and subsequent cracking (or faulting) of the cement.

RP65 has been in place since the summer of 2000 and has approximately 150 members, some of which are 'virtual' members in that they do not attend meetings. Members include the Mineral Management Service (MMS) and the US Department of the Interior who are considering converting the RP65 guidance into a federal Regulation.

The second phase of RP65 is due to be released at the end of April 2007 and will bare relevance to the prevention of CO_2 leaks during well construction and phase 3 is due for publication at the end of 2008 or early in 2009. Phase 3 will cover subjects including the prevention and remediation of CO_2 leaks during injection, production and abandonment. Part 2 will dictate what is needed in each possible scenario, and will lay out a plan for monitoring and verification of storage, while the draft outline for part 3 will cover planning and design through to detection, mechanics and final integrity testing on a preventative level, and from a remedial perspective it will cover sealing methods, repair and evaluation procedures.

5.4.2 Jonathan Koplos, Cadmus Group; A Review of Injection Well Mechanical Integrity Testing Data and Implications for Geosequestration.

Jonathan presented a summary of a study performed with the objectives of drawing key learnings and conclusions for the storage of CO_2 from activities carried out under the Underground Injection Control (UIC) program. The study assessed the availability and quality of data on mechanical integrity testing.

A well that has Mechanical Integrity (MI) is defined as having no leakage in the casing, tubing or packer (internal MI), and no fluid movement vertically along the outside of the wellbore (external MI). A well can only be described as having mechanical integrity if both these criteria are met.

Regulations published in 1980 define 5 different classes of injection wells, and states that an MIT is needed when a well comes into service, and subsequently every five years to ensure compliance with regulations and confirm performance of the well under the UIC program. It is important to specify that MIT failure does not mean well failure or that there is contamination of an underground source of drinking water (USDW). Another important distinction is that even if a well can be shown to have failed an MIT, it could still prove to be suitable for CO_2 injection activities.

The study then gave an analysis of the reasons behind MIT failure, but it was mentioned that on some of the earlier tests, this data is incomplete. The table shows the figures of MIT failures, and if an additional column under the title of inconclusive results was added, the numbers of results in this field would be extremely large, and in some years the number of inconclusive results may be higher than the number of conclusive results.

The number of MIT failures within injection wells used for hazardous waste injection was noticeably higher than those of non-hazardous waste injection, and it is suspected that this is due to a more corrosive injectate. There are additional contributing factors that result in MIT failure other than the injectate substance, and these include the materials used for well construction as these have changed over the years as industry standards became more rigorous.

The conclusions drawn from the study were that maintaining and monitoring the integrity of injection wells is key to ensuring a successful injection program as early identification of mechanical integrity failures or poor results can result in quicker remediation and minimisation of the impact of the failure.

The test results showed that corrosion activity within the well bore environment has an immense impact on the success or failure of MIT's and as CO_2 is a corrosive substance, maintaining mechanical integrity in its presence will play a key role in establishing a high performance well.

Despite the superior construction found in EOR wells that inject acid gas and CO_2 compared to wells that inject water, the acid gas / CO_2 injection wells show a higher MIT failure rate. This indicates the influence of activities or factors outside of the injectate and well activities, i.e. regulations and economic factors can also affect well performance.

The rates and types of MIT failures shown in these results can be used as an analogue to demonstrate general trends in well performance across a range of regulatory and operational conditions over the years, and Jonathan pointed out a spike in one of the graphs which was thought to show a rise in failures representing the time delayed degradation of wellbore cement.

5.4.3 Theresa Watson, Watson & Associates; Alberta Oil and Gas Regulations, the Key to Wellbore Integrity.

Theresa's presentation outlined the history of drilling in the Alberta province of Canada, and the subsequent legislation introduced to govern the activities.

In 1938, the Alberta Petroleum and Natural Gas Conservation Board formed (which was the precursor to the Edmonton Utilities Board, EUB) and the board gathered all the historical data on the 850 previously drilled wells, and they were able to collate data on everything from depths, construction methods, deviation, cement types, to the materials used. The historical data suggests that legislation acted as the driver to develop new technologies to minimise leaks and fluctuations in oil price had a minimal effect on the development of new technologies and drilling methods.

The activities of the Alberta Petroleum and Natural Gas Conservation Board resulted in a large repository of information on the areas wells and drilling activities, and this means that any operators undertaking a CCS project within the province of Alberta will be able to identify abandoned wells within their area of operation and this will also play a part in site selection as the location of abandoned wells will help to determine the reservoirs most at risk of leaks through wells, and those with the greatest security of storage.

The legislation evolved over time to cover protection of groundwater and the atmosphere, particularly from H_2S leaks. During the 1990's, major changes began to occur in the legislation, with specific requirements for abandonment, repair and remediation of leaks, and protection of groundwater was expanded to cover construction and abandonment activities.

Theresa concluded with a view to the future, and forthcoming changes to the regulations to address the use of reservoirs and wellbores in the future, changes to the requirements for surface abandonment and cementing requirements. The government of Alberta is confident that with it's history of detailed drilling and abandonment giving it a large source of information for old and abandoned wells, that it can safely look towards geological sequestration of CO_2 with a minimised risk of leakage and high level of confidence.

6. Discussion Sessions

While previous meetings have featured break-out style discussion groups, it was decided that at this meeting, there would be a series of facilitated discussions involving all the attendees.

6.1 What Conclusions Can We Draw Today About The Viability of CO_2 Sequestration in Reservoirs with Numerous Wells?

The group discussed the relative impacts of external corrosion versus cement quality, and decided that the major factor depends on the conditions present in a particular project, rather than there being a clear cut rule as to which factor has the greater impact. The group then discussed abandonment methods and was split in its opinion as to the use of bridge plugs in abandonment techniques. Some individuals felt they were a suitably efficient manner in which to abandon a well, whereas others felt that the relatively small contact with the well bore meant that corrosion could occur quickly, with the carbonation of the cement leading to profuse well leakage to higher, un-cemented levels of the well bore.

The alternative suggested to using bridge plugs was the option of cementing a well all the way to the surface, although some thought that this was somewhat idealistic as there are obviously economic issues with this method which could be prohibitive. With some individuals raising the question of whether all abandoned wells would need remediation in an old field if there was no evidence of leakage, it was acknowledged that it would be difficult to instigate a CCS project without remediating all the wells, leading to the 'compromise' option of performing a 'ranked' risk assessment of all wells within a storage area, and remediating the wells at a higher risk of leaking, and installing monitoring equipment around lower risk wells. It was pointed out that in the Netherlands, it is not possible to perform a 'shut in' of old wells, so it was necessary to perform risk assessments and then remediate wells with high potential to leak.

The group then discussed the differences between a CO_2-EOR project, and a straight storage project, the main difference being that different regulations apply to a CO_2-EOR project than a disposal / storage project. This leads to the question of how regulation changes take place when an EOR project ends oil production and becomes a solely storage operation, with the added factor that CO_2 storage would most likely take place in a deeper area of the oil producing formation than the production area. It was noted that CO_2EOR operations were a small subset of the activities covered by the current regulations in terms of the operational phase, and storage of CO_2 would fall under different regulations, with different criteria and parameters.

The meeting then discussed the issue of carbon credits awarded for both a CO_2-EOR and a storage project. It was felt that operators of an EOR project would want credit for any injected CO_2 as soon as possible as they would be out of pocket for the period between buying in the carbon for injection and receiving the credits for the storage. It was felt that the requirements for emissions capping would more likely act as the driver for carbon storage rather than the benefits gained from EOR highlighting the need for the system of carbon credits allocation to be both efficient and beneficial to the operator in order to act as an incentive. Whatever the purpose of CO_2 injection, the determination of well bore integrity is still an important factor, and the group agreed that although the best option of well remediation is to cement the well to the surface, it is very costly, and there has to be some distinction between the best practice, and the best, economically feasible practice – also known as BATNEEC (Best Available Technology Not Entailing Excessive Cost).

There is a question over the abandonment method used, and whether it would be different following an EOR project if it was to be subsequently used for CO_2 storage. The differences, if any, would stem from the risk assessments of the site and wells. The health and safety risks associated with a storage project are similar to the health and safety risks involved with a CO_2-EOR project, as the effects of injected CO_2 leaking are the same regardless of the manner or purpose to which the injection took place. The risks involved with greenhouse gas reductions are that if credit has been given under an emissions trading scheme, and the stored CO_2 subsequently leaks out, then the credit given for the reduction in emissions is technically void as the gas has been released to the atmosphere, and not stored. The difference in this risk between an EOR project and a storage project is in the changes within the reservoir. In an EOR project, the injected CO_2 raised the pressure around the production well, but in a storage project, the pressure is increased throughout the entire reservoir, and any weaknesses within the constraining cap rock could be placed under greater strain than through EOR, and this leads to a greater potential for fracturing of the caprock and subsequent migration of CO_2 to the surface and atmosphere. A question that was raised that requires addressing in the future is that of which organisation or government should dictate that if an EOR project converts to CO_2 storage after oil production has ceased, then the existing practices may not cover the legal requirements of a CO_2 storage operation. This was discussed and it was felt that it would be the responsibility of the operator to re-complete wells as necessary to bring them to the standard required for a CO_2 storage project, and that this should not pose significant financial difficulties as the operators are expected to be financially solvent as they will be paid by the producers of the CO_2 for it to be injected and stored.

The new regulations in force in Alberta, Canada state that historically abandoned wells need re-completing using a cement squeeze process, but no verification will be required under the regulation. This results in the technology with the lowest success rate being assumed to work with no subsequent testing and verification. At the same time, new wells are to be drilled to a depth of 15,000 feet, i.e. deeper than existing wells, which negates the problem of previous abandonment processes as the existing wells will not penetrate the storage reservoir.

The issues arising from storage in fields used previously for oil and gas exploitation are leading to an increasing interest in the storage potential in deep saline aquifers. From a mechanical viewpoint, storage in deep saline aquifers is much simpler as storage in a field used for CO_2-EOR will by necessity involve more well bores as there will be wells associated with both injection and production purposes, and production wells can be extremely numerous in some fields, whereas in a deep saline aquifer, there need only be 2 or 3 injection wells. The reservoirs involved in deep saline aquifer storage are also likely to be more intact as there is less history of drilling through the overlying caprock, helping to maintain the reservoir integrity.

Characterisation of deep saline aquifers has not yet been performed on anything above a pilot scale as the only active projects are currently at the pilot scale and are therefore of a small scale and entail minimal risks. In the near future, a full characterisation will be required in order to validate the safety of CO_2 storage in deep saline aquifers.

The group discussed leakage from a storage reservoir, and whether any level of leak could be deemed as acceptable. It was decided that if there was an acceptable level of leakage, a leak of less than a specified percent could be feasibly ignored, and this could reduce the number of wells requiring remediation by up to 75%, depending on the level of leakage determined as acceptable. A point was raised over the lack of evidence of CO_2 leaking into brine formation waters during a period of 30 years that is backed up with data, although this data is perhaps not as quantifiable as would be necessary to justify and prove the results beyond doubt.

The group concluded that a balancing procedure was required between the opposing options of cementing to the surface and installing a 50m section of high quality cement. It is possible that information readily available from CO_2EOR operations could be transferable and therefore provide a short-cut to the verification of abandonment techniques and demonstrate suitability for storage much more quickly and efficiently.

The establishment of a database of techniques and requirements would have to encompass a large number of variables and scenarios, the example was given of storage within the Los Angeles basin in the USA where the presence of a large number of tectonic faults provide numerous existing and potential leakage pathways, with the likelihood of disruption to the cap rock being high due to ongoing tectonic movements. Another difficulty in building a database is the lack of detailed knowledge in some areas. It is not always feasibly possible to know and re-complete all wells in an area, especially when an area is thought to include some comparatively old wells, on which little or no data is available – including location in some instances.

Another opinion offered was that leaks will occur, so efforts should be funnelled into attempting to determine what flux rates are more likely to give rise to problems – i.e. leaks above a predetermined level or rate, and what leaks can be ignored as insignificant. It was suggested that this would be an exercise that would be location specific, and therefore time consuming, but also unsuitable as allocation of carbon credits under an Emissions Trading Scheme (ETS) would have to be based on a net storage value – i.e. the quantifiable amount of carbon stored, and this would necessarily impose strict controls on leakages as credit cannot be seen to be given for carbon emissions that have subsequently been released to the atmosphere.

6.2 Can Experiments Provide Critical Parameters for Modelling and Actually Demonstrate the Viability of Wellbore Seals?

A question was taken from the floor regarding one of the points raised in the afternoon's presentations. The questioner asked whether it was considered that the iron used in concrete reinforcement would have an effect on the degradation and carbonation of the cement when the iron used for the reinforcing degraded and corroded over time. The question was answered by several of the afternoon's speakers and the consensus was that although it may have an affect, it had not been observed in any situations, and was a mechanical process rather than a chemical reaction, and as such, the interaction and effect would be minimal when compared to the chemical reactions occurring over the same time period.

Another participant had a technical query regarding the use of additives in the experiments, and whether the water used was varied to determine the effects, if any, that this may have on the results. It was confirmed that the water remained as a constant as the industry standards call for both the cement and the water to remain unchanged throughout the course of the experiments involving the testing of reactions with additives. The water ratios used within the industry have changed historically, but this has been a purely economic consideration in order to minimise the costs involved with construction. Practices within the scope of CCS define a different set of requirements than the construction industry.

Stefan Bachu commented that from a CCS perspective, permeability and porosity of the well bore cement is possibly the most vital factor when considering integrity, and that flow cannot be ignored, but is very hard to replicate accurately the field conditions experienced within a laboratory. This responded to several delegates' comments on the subject.

Another question was raised regarding composite experiments and why flow-by as well as flow-through wasn't replicated and monitored. Bill Carey stepped up to confirm that laboratory testing did in fact simulate both types of interface (cement and casing, and cement and cap rock) and flow, not just diffusional flow. Bob Svec went on to comment that in the experimental procedure followed by his study, flow was induced, but equipment does not allow participants to measure or create flow through the cement. In order to do this, an experiment would need to be extremely large scale, with a large caprock / sandstone interface within the laboratory, and this would result in excessive cost which wouldn't be considered feasible.

Rich Chalaturnyk raised the question of the relevance of the laboratory based experiments using either distilled water or 3M brine. He asked how these fluids reflected the fluids found in field based projects and how 'field' water might affect differences and changes to the reactions modelled in the lab using the different fluids. Again, the answer came from the floor and the consensus was that any contaminants in the water found in field projects may have the potential to cause problems during the initial set-up of a project, but any effects or impacts are short lived and cause no lasting problems or obstacles to be overcome.

Ideas were taken on which directions future experiments could take, and several suggestions were made with reference to laboratory based experiments placing some kind of confining loop on a bridge plug to determine the limits to which a plug may be able to withstand compressive stresses and go some way towards preventing or minimising the degradation experienced by the bridge plug.

Questions asked in the closing of the session covered topics such as the speed of flow through degraded cement in old abandoned wells, and whether the flow is faster the more degraded the cement was. It was propounded that the speed of flow in abandoned degraded wells depended on the reservoir and the injection pressures encountered rather than the state and age of the cement degradation. It was suggested that the rate of flow would most likely to be of the order of inches to maybe one or two feet per year. The implication of this is that diffusion is the main degradatory process found in well bores rather than reservoir flow.

The final question of the session was whether there had been any analysis of the effects of the cement on the surrounding formation rock and the response was that there is usually no reaction at all, and that it is thought that this is at least partially due to the drilling mud acting as a buffer between the two materials, preventing sustained contact from occurring.

6.3 How Can Numerical Models of Wellbore Integrity be Validated?

Charles Christopher identified two major driving forces which affect wellbore integrity, and these were reservoir pressure, and buoyancy. He went on do outline the fact that we know that reactions are primarily limited by diffusion, but that many other factors also play an important role in diffusion. The parameters can be shown along with their impact and severity in a table as follows.

Parameter	Increase or Decrease	Confidence in Understanding Interaction
Water / Cement Ratio	Increase	High
Permeability	Increase	High
Pressure[3]	Increase (weak)	Uncertain
Temperature	Increase	Complicated
Gas / Supercritical Phase	Complicated	Very complicated
Salinity (NaCl – not quartz)	Decrease	High
Capillary pressure	Increase	Low
Curing of Cement	Increase	Low

The group then discussed what this meant in terms of the focus for future projects and research, and the consensus was that future projects should be more focussed on specific areas, to provide more in depth results on individual topics. Projects will need to be better financed, but this will be aided by knowledge gained from previous research which will allow start-up problems to be avoided, and research will look to old wells to learn from them and translate this knowledge to new projects and activities.

Abandoned wells within the industry have provided evidence of CO_2 being detected at the well head, but it is unclear whether this is due to CO_2 induced degradation of the cement, or due to poor completion practices. Future projects must investigate this phenomenon to determine the cause of such leaks, and there is a source of data available that contains information on drilling methods, leakage history and well completion methods for some areas, and this source is held in a database constructed by BP.

"If a well significantly leaks, we can detect it and go and fix it." Charles Christopher, BP

6.4 How Should the Performance of New and Old Wells be Validated in a Regulatory Environment?

The final discussion session focussed on the question of validation of the performance of old and new wells in a regulatory environment.

The discussion quickly decided that new wells would be subject to controls in all aspects of design, installation and use in order to minimise the possibility of leakage, and problems were likely to come from existing wells, and indeed, some older CO_2 wells are beginning to fail.

[3] The reactions associated with pressure vary depending on what type of pressure is being discussed, hence the complicated nature of the interaction and the uncertainty associated with the level of its impact.

The major issue with existing wells is the huge number. For example, Texas and Alberta have a very large number of existing and abandoned wells, and whereas Alberta have a large repository of information available on their existing wells, records in Texas are not as comprehensive, and the number of wells is higher – some estimates state that there may be up to 1 million existing wells within the state. If the storage community moves towards storage in deep saline aquifers, the problem may not be as serious as there are fewer wells penetrating deep saline aquifer formations than there are penetrating oil and gas fields. It was pointed out that although these wells may be fewer in number, they may well be poorer in terms of quality, integrity and abandonment.

Stefan Bachu said that although there may be a requirement for different regulations for new wells for CO_2 injection purposes compared with new wells for any other purposes, this is not the case at present, and therefore existing wells remain an issue, and today's new wells become tomorrows existing wells.

The question was raised of whether, in the scope of a complete CCS project, re-completion of wells was a major economic factor as some projects may run to billions of dollars, but the answer coming from the group was that re-completion may cost up to $500 million per well, so there would be a significant adverse effect on the economy of a project if multiple re-completions were required.

Another issue that was subjected to debate without a definitive answer forthcoming was that of whether in a small-scale, small field test with a potential, yet small, risk of leakage; is it acceptable to allow it to occur? The only definitive conclusion drawn from this area of discussion was that any and every CCS project needs to address the total field involved, and assess the requirements with regard to the scale of the plume migration to determine the areas of influence.

The next point discussed was the scenario of there being 2 or 3 levels of caprock between the new injection well and the existing well. In this situation, the existing well, a potential leakage pathway, does not neighbour the injection reservoir, and we have to determine some guidelines for stacked reservoirs. There has to be a ceiling limit applied to such stacked systems, but what should this limit be? No-one could justify a position, although many different opinions were given. The consensus was reached that a reasonable limit would have to be decided upon, and this limit should take into account the local reservoir system and the integrity of each of the layers of caprock, as well as a comprehensive risk assessment and economic considerations. Without the inclusion of economic considerations, we run the risk of drastically reducing the number of storage reservoirs that can be considered for storage, and subsequently reducing the global storage capacity for geological storage of CO_2. The same argument has to be applied to storage in deep saline aquifers as there are generally fewer traps in deep saline aquifers, so the same method of justification reduces the storage capacity of the deep saline aquifer media as well.

Debating whether or not leaks can be deemed as acceptable, and how best to avoid and minimise the potential for them has been discussed at length with wither little or no significant decisions being made. As an alternative to this, a suggestion has been made that more input and investment should be channelled into the development of a better suite of monitoring and remediation tools to deal with leaks, as it seems that even with the most stringent of control mechanisms and tightest regulations and site selection criteria, it may not be possible to remove the possibility of a leak from a storage reservoir.

Some simple common sense removes some potential storage reservoirs from consideration. For example, in West Texas, the population density is 16 people per square mile, and many of the abandoned wells are known to be underneath buildings, or close to population centres. The associated reservoirs can therefore be immediately discarded as potential storage sites, and this allows concentration of investigative resources and capital in areas that have increased chances of being suitable for CO_2 storage.

If storage operations are commenced now in the areas that are 'safest' new technological and monitoring tool developments will then allow storage operations to move to more sensitive areas in terms of ecology, ecosystem, and population proximity.

One somewhat risky and careless approach to development is derived from the experience of the oil and gas industry. When exploration first gained pace, there were one or two large scale disasters which directly led to huge technological advancements and improvements in safety. This is dubbed the 'Train Wreck' scenario, and some consider it reckless, as it can be deemed to ignore known health and safety concerns in an attempt to further development of a technology.

A more balanced approach is to incorporate into the site selection process an identification and ranking exercise. In this approach, the site selection process identifies all the wells within a storage area, and determines whether they pose a security risk in terms of leakage. All wells considered as 'at risk' are then addressed in a ranked order, unless there are considered too many wells in the 'at risk' category, in which case the site is classed as uneconomical for storage, and the process restarts at the next potential site.

Although economics of storage projects are being discussed alongside regulations, it should be noted that economic considerations should not play a part in the activities or decision making processes of regulators as economic considerations are considerations of the project operators and regulators should concentrate their focus on risk assessments.

7. Summary

After a varied and interesting programme of presentations and in-depth discussions, Charles Christopher gave a summary of the meeting, and congratulated all those present for the progress that had been made in the preceding year. It was clear that everyone still derived a great benefit from the meetings, and the length and detail in the discussion sessions proved just how far the group has come, but there is still a long way to go.

One of the greatest differences noticed in this meeting was that many presentations were results of laboratory and field experiments, clear evidence that the community and interested parties are now actually 'doing' and carrying out experiments, rather than 'talking' about purely theoretical ideas.

There is a feeling of progress made, which Charles hoped would continue well into the future, and next year's meeting would hopefully go even further to proving the on-going value of these workshops and network meetings.

Stefan Bachu agreed that the progress that had been made was a good step, but in order to progress further, the group and subject needed to reach a wider audience, and the steering committee were asked to include and invite more regulators and non-governmental organisations, and this was backed up by both Elizabeth Scheehle and Rajesh Pawar. This was fielded by John Gale, who said that the regulators and NGO's were already invited to the meetings, but unless the meetings were held very close to their offices, they were reluctant to attend.

The new journal being published in conjunction with Elsevier[4] may prove to be a useful platform to increase the audience of the network, and John Gale and Stefan Bachu will happily consider papers for submission to the journal, and if sufficient papers are received and accepted, then a subject specific issue may be possible.

[4] International Journal of Greenhouse Gas Control.

8. Conclusions

The key conclusions that can be drawn from the meeting are:

1. There is currently a notable contrast between the laboratory and field based research results and data, and the results from the field are much more promising for CCS activities than those obtained from the laboratory. This discrepancy requires further in-depth investigation, and if necessary processes and procedures used in the laboratory need to be adjusted to more closely replicate the conditions experienced in the field to allow more accurate analogues and simulation modelling.

2. We have a much greater understanding of the interactions and reactions present in the wellbore environment, and can predict and understand the relationships between the injected CO_2, the wellbore (including the casing), the caprock and the formation water / reservoir. Understanding and forecasting these reactions is key to proper well design and safety and security of geological storage of CO_2.

3. There is a much more varied interest in the subject of CCS, and partly as a result in this greater input, the state of knowledge and technologies have advances significantly in the past year, and we can confidently expect more developments and technological advancements in the years to come.

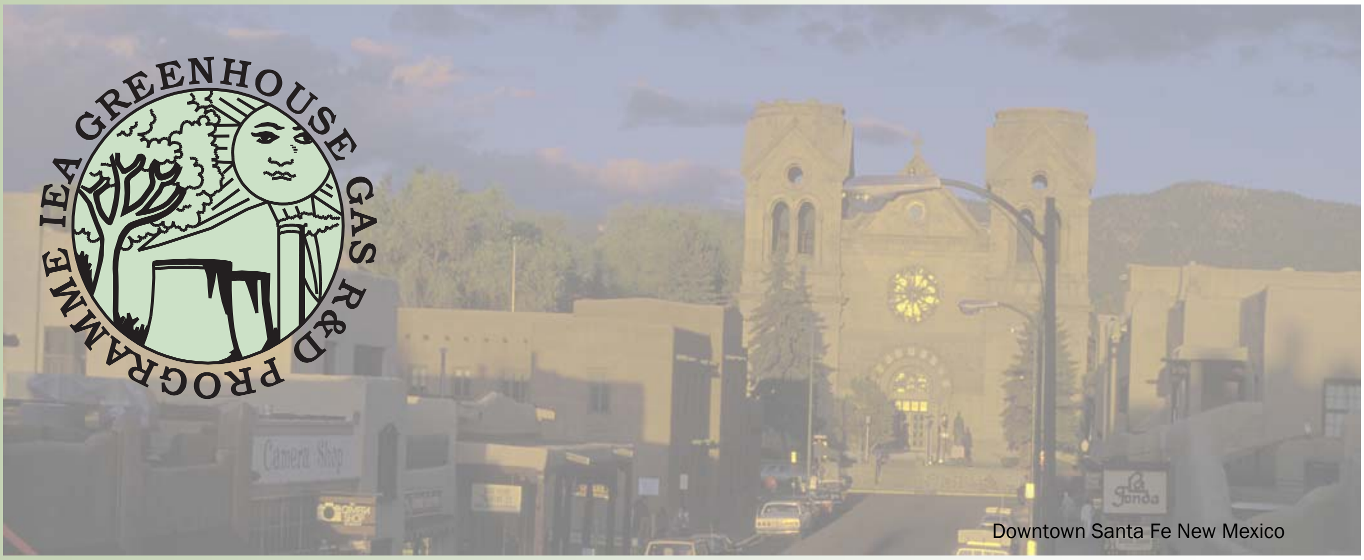
4. Simulations and models are becoming more detailed and flexible, and in particular the presentation of LANL's CO_2PENS model appears to incorporate most factors and impacts likely to need consideration under CCS regulations, and has the scope to adjust to most scenarios of storage.

APPENDIX 1

ATTENDEE LIST

Delegates attending the third Well Bore Integrity Network Meeting, March 12th-13th 2007 La Fonda, Santa Fe, New Mexico, USA	
Toby Aiken	IEA GHG
Glen Benge	Exxon Mobil
Ron Sweatman	Halliburton
Jeremie Saint-Marc	Total
Heath Nevels	Shell International E&P
Frans Mulders	TNO
Nicolas Jacquement	BRGM
Sam Lewis	Halliburton
John Gale	IEA GHG
Barbara Kutchko	US DOE / NETL
Brian Stazisar	US DOE / NETL
Charles Christopher	BP
Michael Parker	Exxon Mobil Production Company
Stefan Bachu	Alberta Energy and Utilities Board
Theresa Watson	T.L. Watson & Associates
Rick Chalaturnjurnyk	University of Alberta
Elizabeth Scheehle	USEPA
Andre Garnier	Total E&P
Bruno Huet	Princeton University
Walter Crow	BP / EPTG
Andrew Duguid	Schlumberger Carbon Services
John Grube	Illinois State Geological Survey
Steve Crookshank	American Petroleum Institute
Mark Looney	Chevron
Craig Gardner	Chevron Energy Technology Company
Veronique Bartlet-Gouedard	Schlumberger
Gaetan Rimmele	Schlumberger
Jonathan Koplos	Cadmus Group
Jesse Claffey	Schlumberger Carbon Services
Cathy Wilson	Los Alamos National Laboratory
Rajesh Pawar	Los Alamos National Laboratory
Nevio Moroni	ENI Exploration & Production
Kenneth Krupka	Pacific Northwest National Laboratory
Sarah Gasda	Princeton University
George Guthrie	Los Alamos National Laboratory
Ann Bustos-Gonzales	Los Alamos National Laboratory
Bill Carey	Los Alamos National Laboratory
Scott Imbus	Chevron Energy Technology Company
Michael de Vos	State Supervision of Mines
Chris Hawkes	University of Saskatchewan
Vello Kuuskraa	Advanced Resources International
Niels Thaulow	RJ Lee Group Inc.
Eric Le Colier	IFP
Reid Grigg	Petroleum Recovery Research Centre, New Mexico Tech
Marcus Wigand	Los Alamos National Laboratory
Bob Svec	Petroleum Recovery Research Centre, New Mexico Tech
Jean-Philippe Nicot	Bureau of Economic Geology, The University of Texas, Austin
Robert Carpenter	Chevron Engineering & Technology Company

Tor Harald Hanssen	Statoil
Arne Valland	Statoil
Kris Ravi	Halliburton
William O'Connor	US DOE
Matteo Loizzo	Schlumberger
Karen Cohen	US DOE / NETL
Peter Lichtner	Los Alamos National Laboratory
John Kaszuba	Los Alamos National Laboratory
Cal Cooper	Conoco Phillips
Harry Limb	Conoco Phillips
Richard Rhudy	Electrical Power Research Institute
Wendy Cheung	EPA
Mike Stenhouse	Monitor Scientific
James Anderson	Shell Oil
Mary Neu	Los Alamos National Laboratory



Downtown Santa Fe New Mexico

3rd Wellbore Integrity Network Meeting

12th-13th March 2007

La Fonda Hotel, Santa Fe, New Mexico, USA

Organised by

IEA Greenhouse Gas R&D Programme.

Sponsored by

Epri

Please note: Daylight Savings Time begins Sunday 11th March. The clocks go forward 1 hour.

12th March 2007 Day 1

07.30 to 08.30 Continental Breakfast and Registration: Mezzanine Room; Meeting to be in the Ballroom South

Session 1– Introduction

08.30 to 08.45 Welcome Address; Charles Christopher Bp, John Gale IEA GHG, Bill Carey LANL.

08.45 to 09.00 LANL Welcome; Mary Neu and George Guthrie LANL.

Session 2-Field Studies/Surveys of Wellbore Performance and Reliability

09.00 to 09.25 Factors Affecting or Indicating Potential Wellbore Leakage; Stefan Bachu, EUB and Theresa Watson, Watson & Associates

09.25 to 09.50 A Comprehensive Wellbore Integrity Program; Charles Christopher, BP

09.50 to 10.15 Analysis of Abandoned Well Integrity at a Potential CO_2 Storage Site: Frans Mulders; TNO

10.15 to 10.40 Break: Mezzanine Room

10.40 to 11.05 Role of Permanent Downhole Integrated Instrumentation Systems in Assessing Wellbore Performance - Penn West CO2-EOR Monitoring Project: Rick Chalaturnyk; University of Alberta

11.05 to 12.05 **Facilitated Discussion**
Theme: What conclusions can we draw today about the viability of CO_2 sequestration in reservoirs with numerous wells?

12.30 to 13.30 Lunch: Ballroom North

Session 3—Cement-CO2 Interaction Experiments and Observations

13.30 to 13.55 Degradation of Wellbore Cements: Results of Long-Term Experiments and Effect of Additives: Barbara Kutchko and Brian Strazisar; NETL

13.55 to 14.20 Core-Flood and Batch Experiments on Carbon Casing-Cement-Shale Composites: Marcus Wigand; LANL

14.20to 14.45 CO_2 Flooding Applications for Cores and Cement/Casing Composites: Bob Svec and Reid Grigg, New Mexico Tech.

14.45 to 15.20 Break: Mezzanine Room

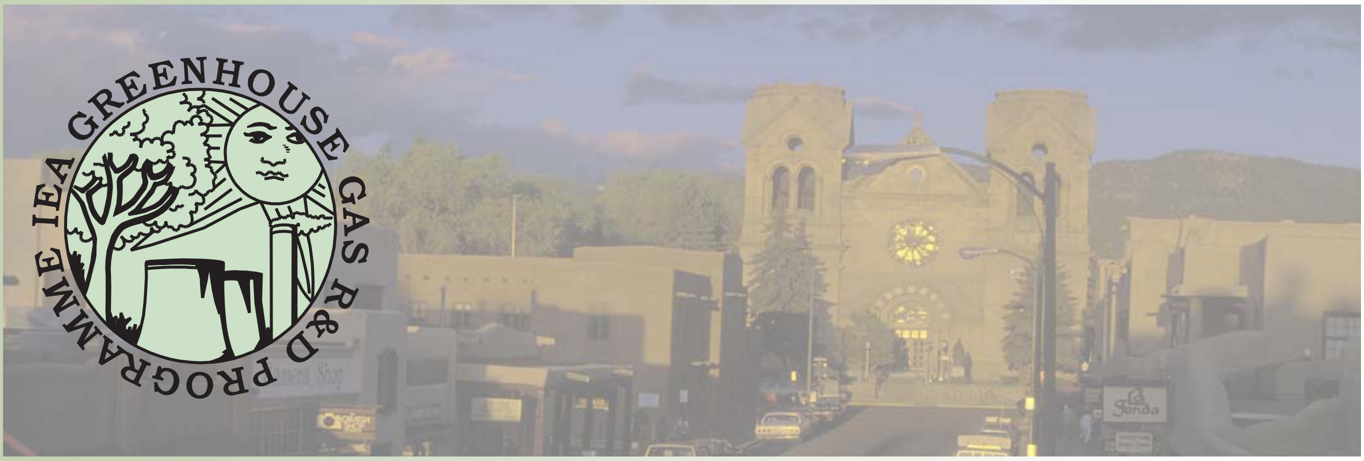
15.20 to 15.45 Carbonation of Concrete Structures: Niels Thaulow; R.J.Lee Group.

15.45 to 16.05 Behaviour of Portland Cement in CO_2 Rich Water/Brine. Implications on Wellbore Integrity for CO_2 Storage: Veronique Bartlet-Gouedard; Schlumberger

16.05 to 17.05 **Facilitated Discussion**
Theme: Can experiments provide critical parameters for modelling and actually demonstrate the viability of wellbore seals?

18.00 to19.00 Poster Session and Reception: La Fonda Hotel

Close Day 1
19.00 Dinner sponsored by EPRI :La Terraza



13th March 2007 Day 2

07.30 to 08.30 Continental Breakfast: Mezzanine Room; Meeting to be in the Ballroom South

Session 4—Numerical Modelling & Experiments of the Near– and Far-Field Wellbore Environment

08.30 to 08.55	Well Cement Ageing in Various H_2S-CO_2 Fluids at High Pressure and High Temperature: Experiments and Modelling: Nicolas Jacquement; French Geological Survey.
08.55 to 09.20	Simulation of Cement Reactivity with CO_2 in the Wellbore Environment: Peter Lichtner/ Bill Carey/ Chaun Lu; LANL
09.20 to 09.55	Measuring Effective Wellbore Permeability: A Numerical Analysis of a Field Pressure Test: Sarah Gasda; Princeton University.

09.55 to 10.20 Break: Mezzanine Room

10.20 to 10.55	Assessing Wellbore Leakage and its Potential Impact Through CO2-PENS, a Systems Level Model: Rajesh Pawar; LANL
10.55 to 12.00	**Facilitated Discussion** Theme: How can numerical modells of wellbore performance be validated?

12.00 to 13.30 Lunch: Ballroom North

Session 5– Policies, Regulations and Best Practices

13.30 to 13.55	API philosophy and Approach to Wellbore Integrity: Ron Sweatman; Halliburton.
13.55 to 14.20	A Review of Injection Well Mechanical Integrity Testing Data and implications for Geosequestration: Jonathan Koplos; Cadmus Group.
14.20 to 14.55	An overview of Alberta Regulations, Past and Present– Ensuring Wellbore Integrity: Thersea Watson; Watson & Associates

14.55 to 15.20 Break: Mezzanine Room

15.20 to 16.20	**Facilitated Discussion** Theme: How should the performance of new and old wells be validated in a regulatory environment?

Session 6– Summary, Discussion and Close: Chair; Charles Christopher, BP

16.30 to 17.00	Concluding discussions, Next Steps and Proposal for Next Meeting

Closing Session-Wrapping up and Future Activities

EUB Alberta Energy and Utilities Board

Factors Affecting or Indicating Potential Wellbore Leakage

Dr. Stefan Bachu

Alberta Energy and Utilities Board
Stefan.Bachu@gov.ab.ca

Theresa Watson

T.L. Watson and Associates Inc.
Theresa.Watson@TLWatson.com

EUB Alberta Energy and Utilities Board
Alberta Geological Survey
AGS

T.L. WATSON & ASSOCIATES INC.

AGS

Old Wells or New Wells?

Should we worry more about the integrity of future CO_2 injection wells, or about the existing and future wells drilled for purposes other than CO_2 injection?

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Deep Wells Drilled in Alberta

End of 2004

- 316,439 total
- 108,706 abandoned

End of 2006

- 362,265 total
- 116,550 abandoned

Oldest: 1893

Area: 664,332 km^2
(256,610 sq.mi)

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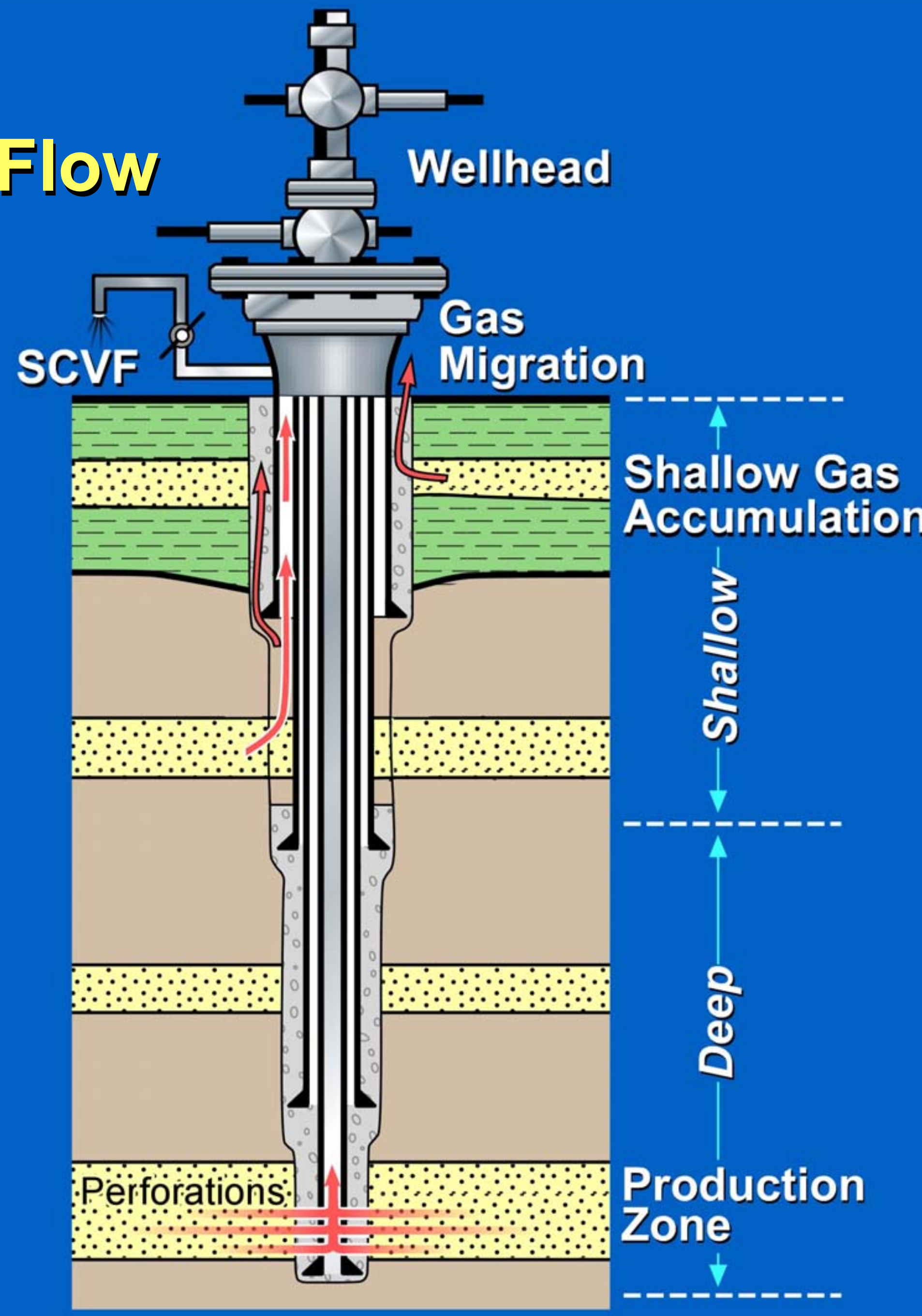
Conditions for Well Leakage Occurrence

- Leak source
- Driving force (head differential, buoyancy)
- Leakage pathway
  - Poorly cemented casing/hole annulus
  - Casing failure
  - Abandonment failure

EUB Alberta Energy and Utilities Board

Surface Casing Vent Flow and Gas Migration Flow Pathways in a Well



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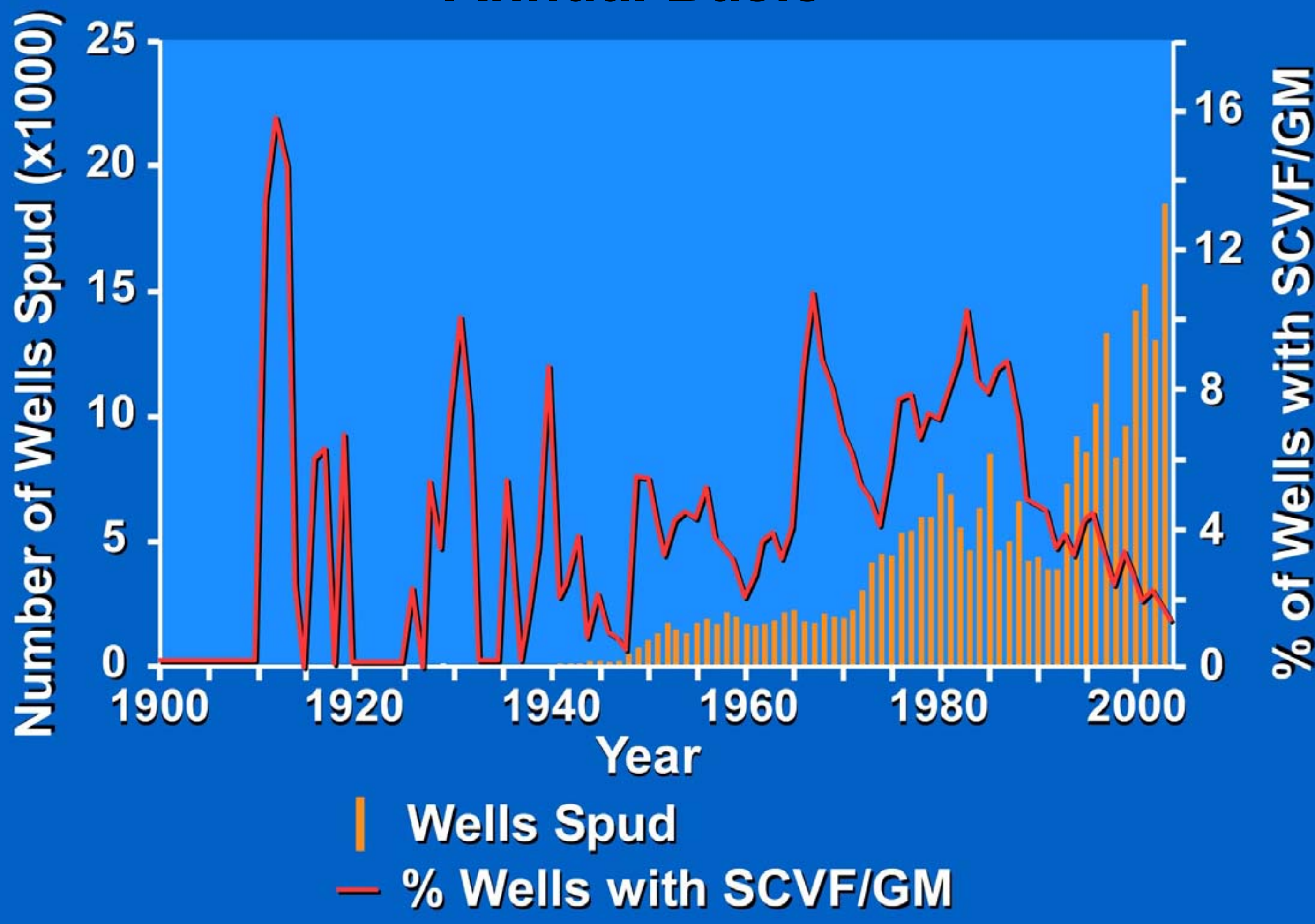
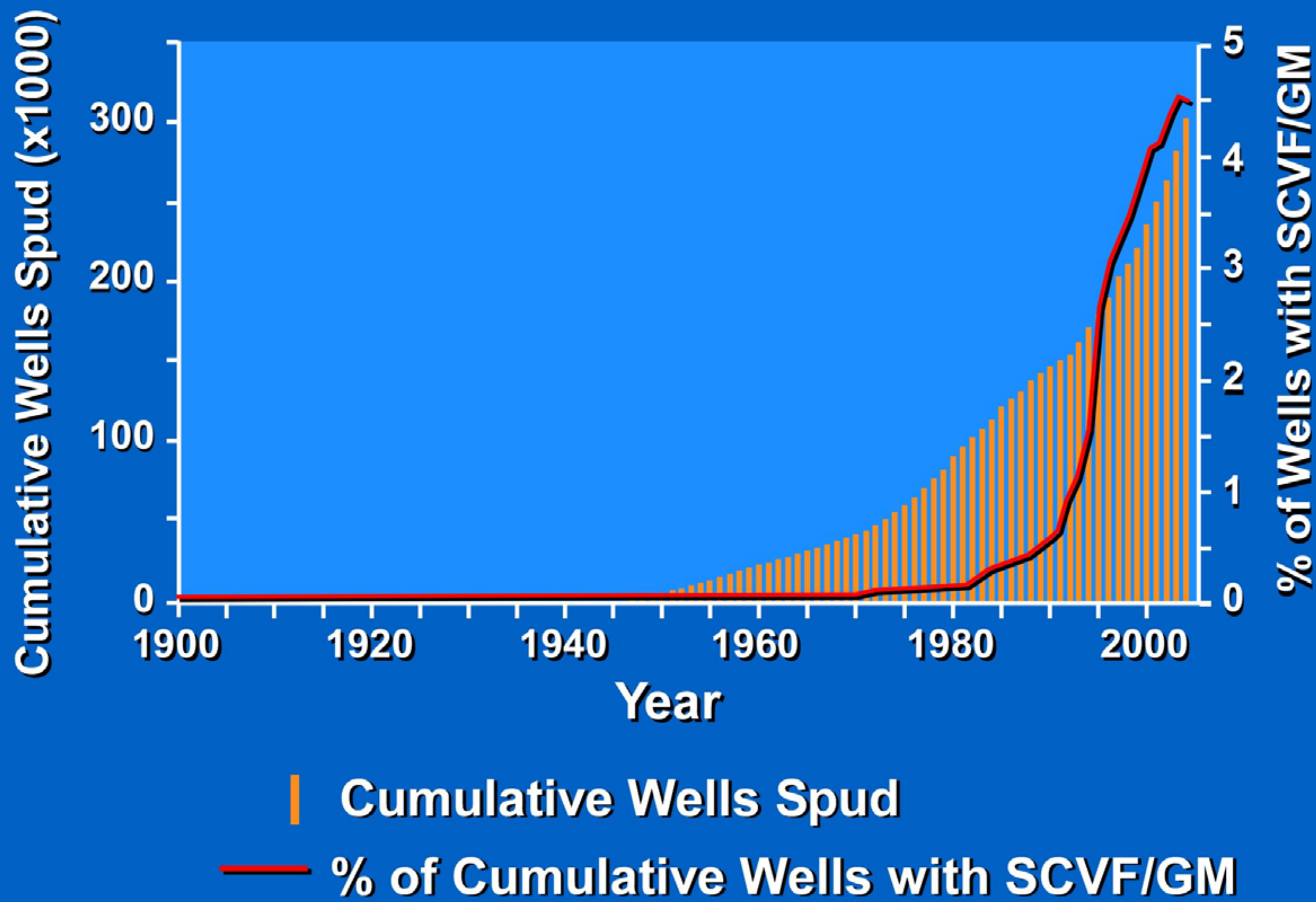
Wells with SCVF/GM Compared with Wells Drilled
- Annual Basis -



Alberta Energy and Utilities Board

Wells with SCVF/GM Compared with Wells Drilled
- Cumulative -



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Example of SCVF and GM Testing

① Testing for SCVF ② Testing for GM

Abandoned Well Leaking Brine and Gas near Peace River, Alberta

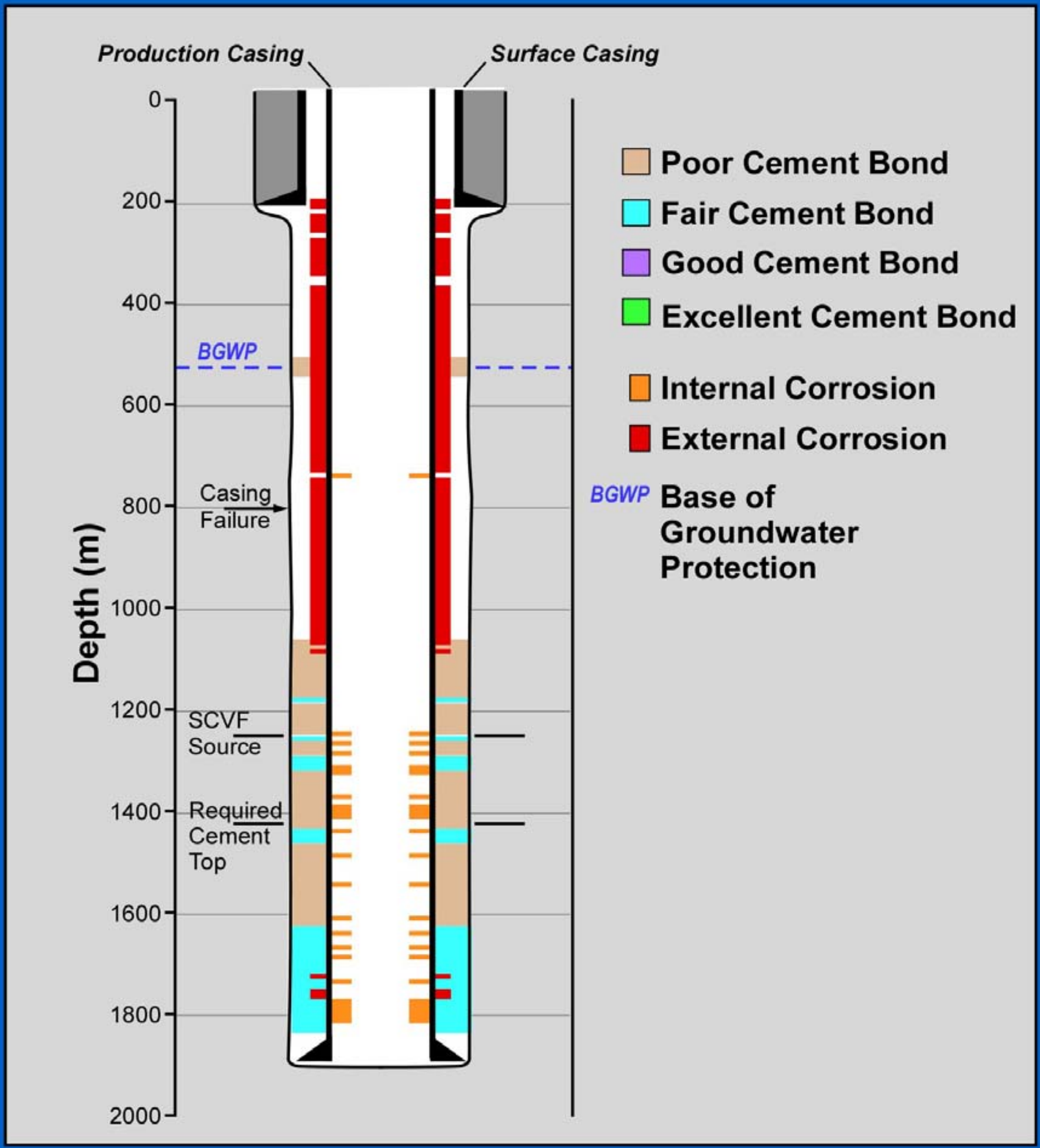
Gas Bubbling at the Cap Welding of the Surface Casing

Gas Bubbling at the Cap Welding of the Production Casing

Analysis of Factors Affecting Well Leakage

- Data mining
  - EUB's public databases on wells and production
  - EUB's databases on SCVF, GM, casing failure and non-routine well abandonment
- Historical documents and regulatory changes
- Casing inspection logs and cement logs for ~500 wells, of which 142 had adequate data for full evaluation
- Depth of groundwater protection

Example of Cement and Casing Quality in a Well in the Haynes Field, Alberta



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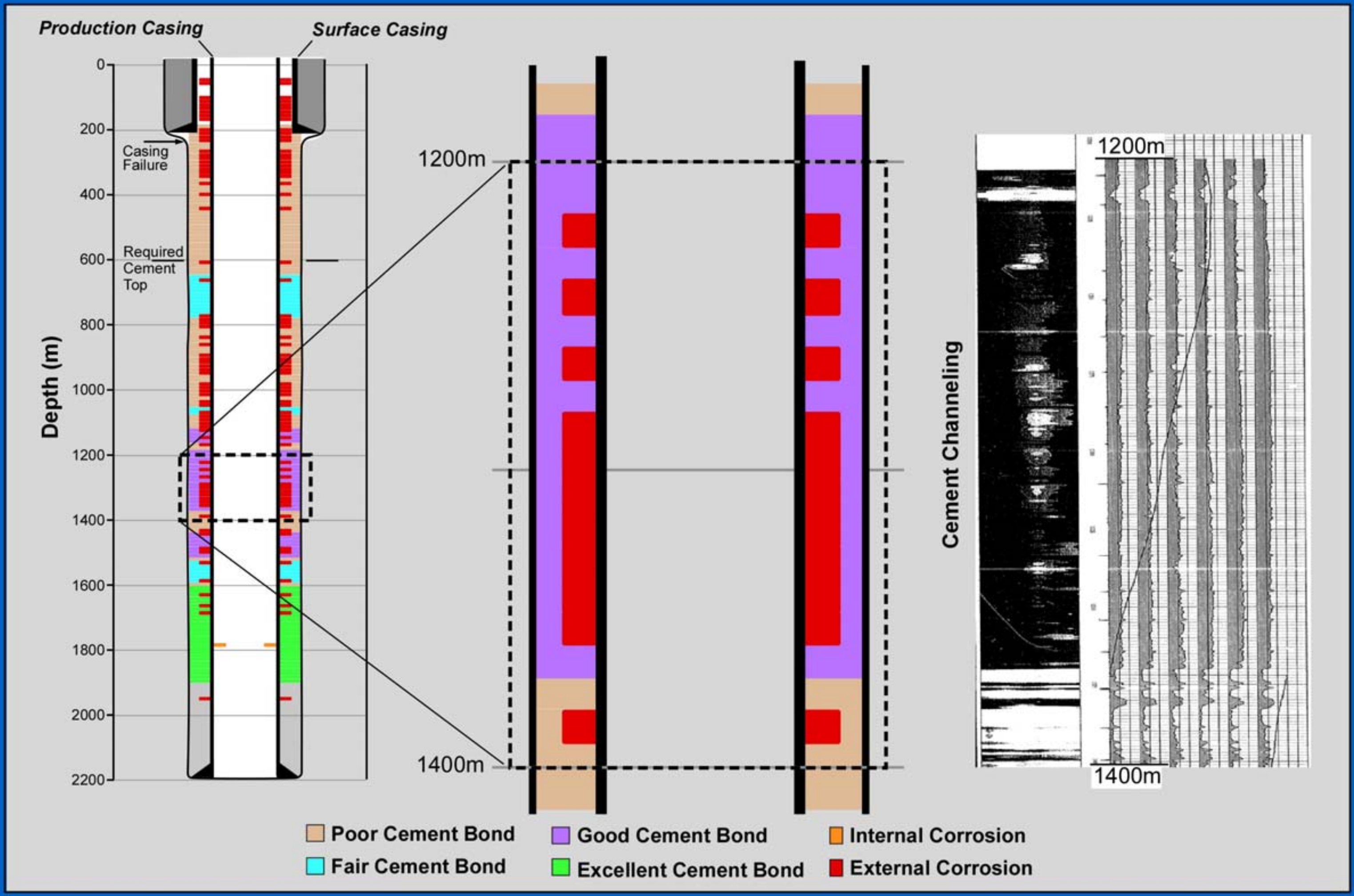
Example of Well Log Analysis Showing Corrosion Due to Cement Channeling



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Factors of No Apparent Impact

- Well age
- Well operational mode: production, injection or disposal
- Completion interval
- Presence of H_2S and/or CO_2

Factors of Minor Impact

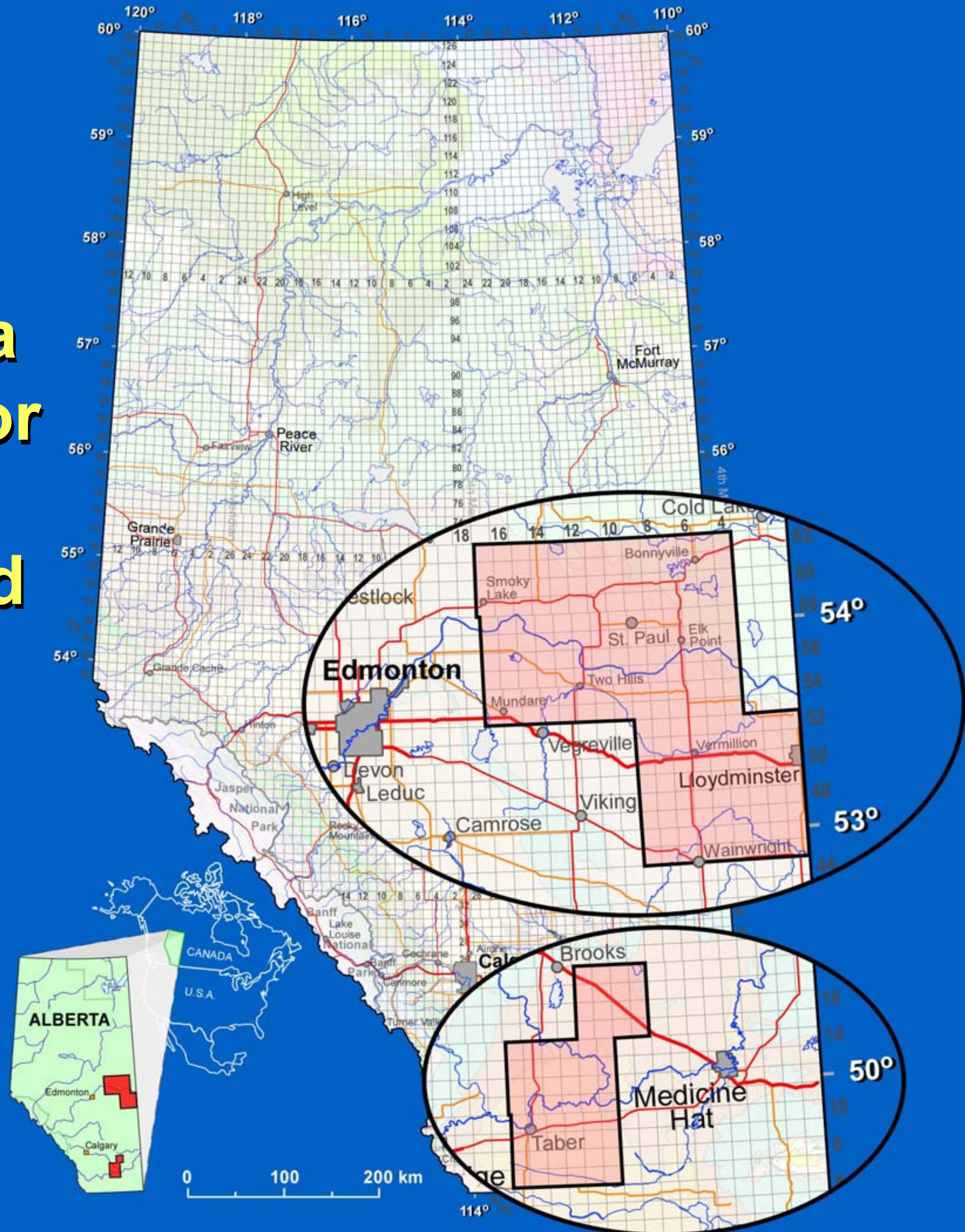
- Licensee
- Depth of surface casing
- Total depth
- Well density
- Topography

Factors of Major Impact

- Geographic area (Test Area)
- Well deviation
- Well type:
  - drilled and abandoned (SCVF/GM incidence rate of 0.5%)
  - cased and abandoned (SCVF/GM incidence rate of 14%), for 98% of the total
- Abandonment method (bridge plugs, welded caps)
- Economic activity, regulatory changes and SCVF/GM testing
- Uncemented casing/hole annulus!

Alberta Energy and Utilities Board

Areas in Alberta where Testing for Gas Migration was/is Required



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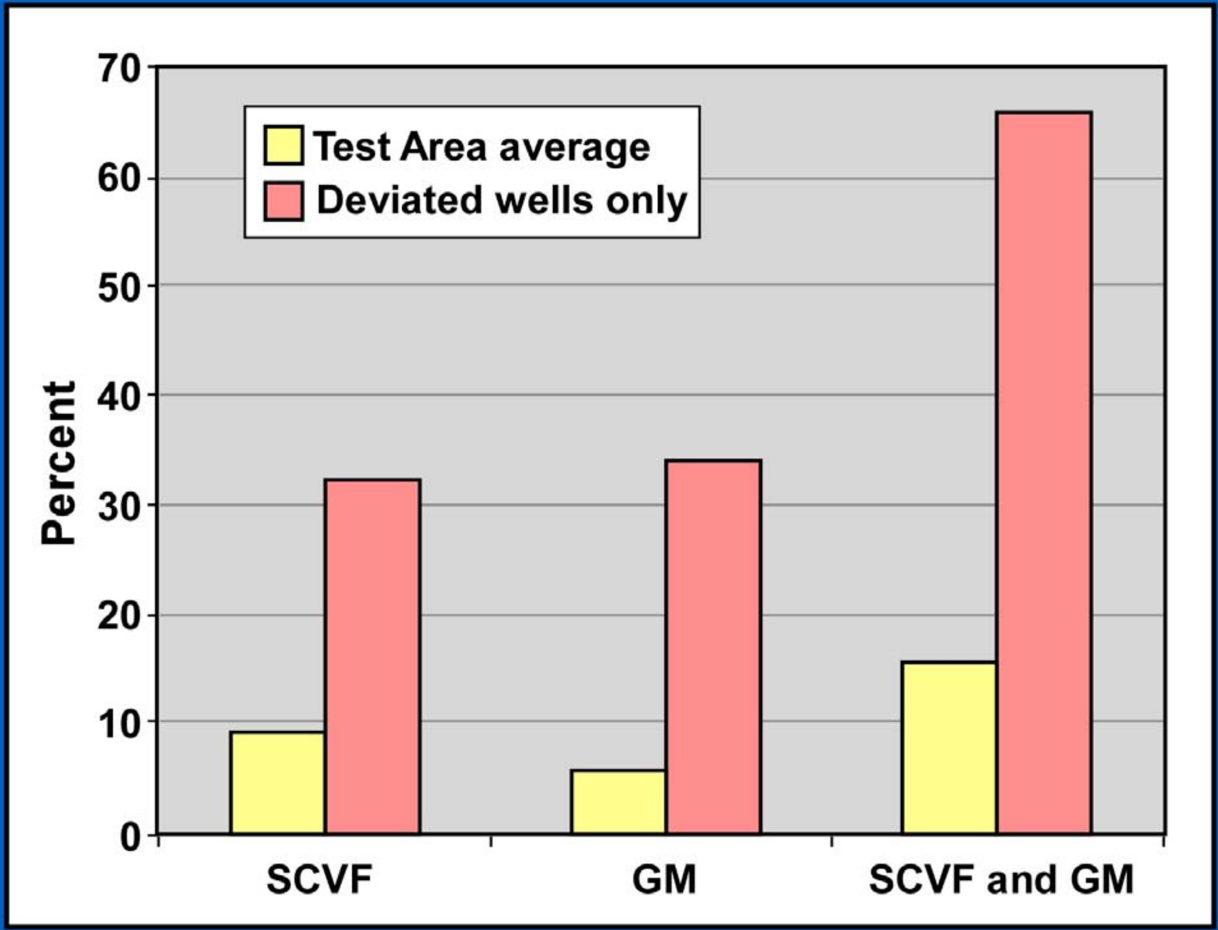
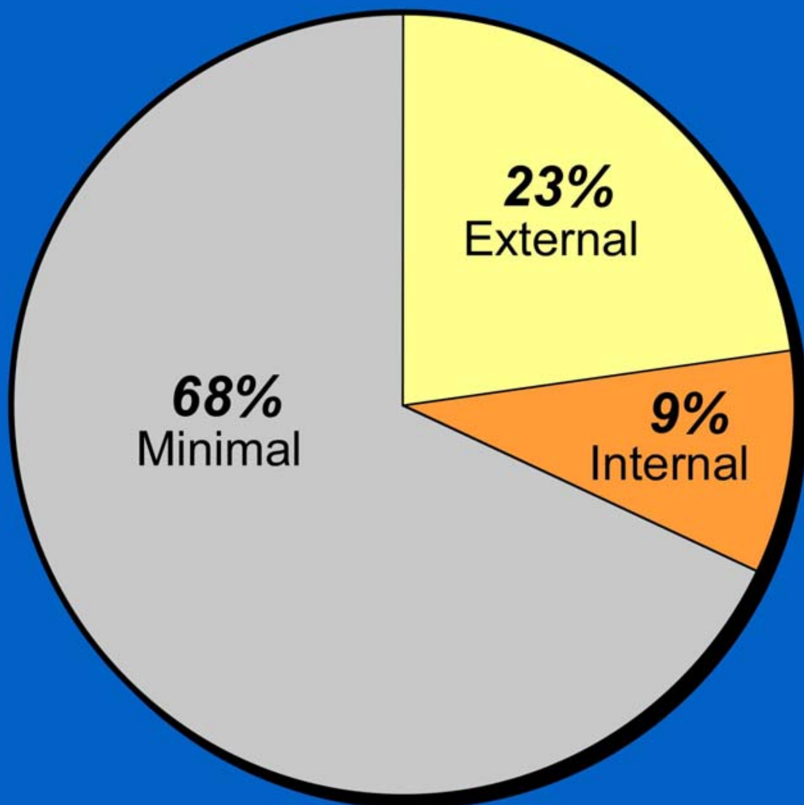
Occurrence of SCVF/GM in the Test Area, Alberta

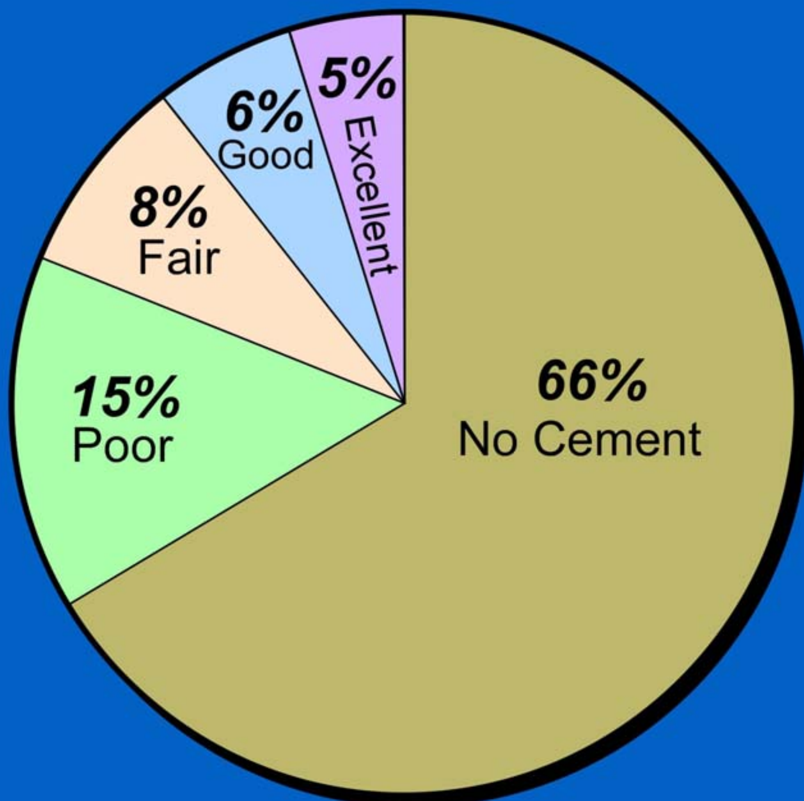


Corrosion Location



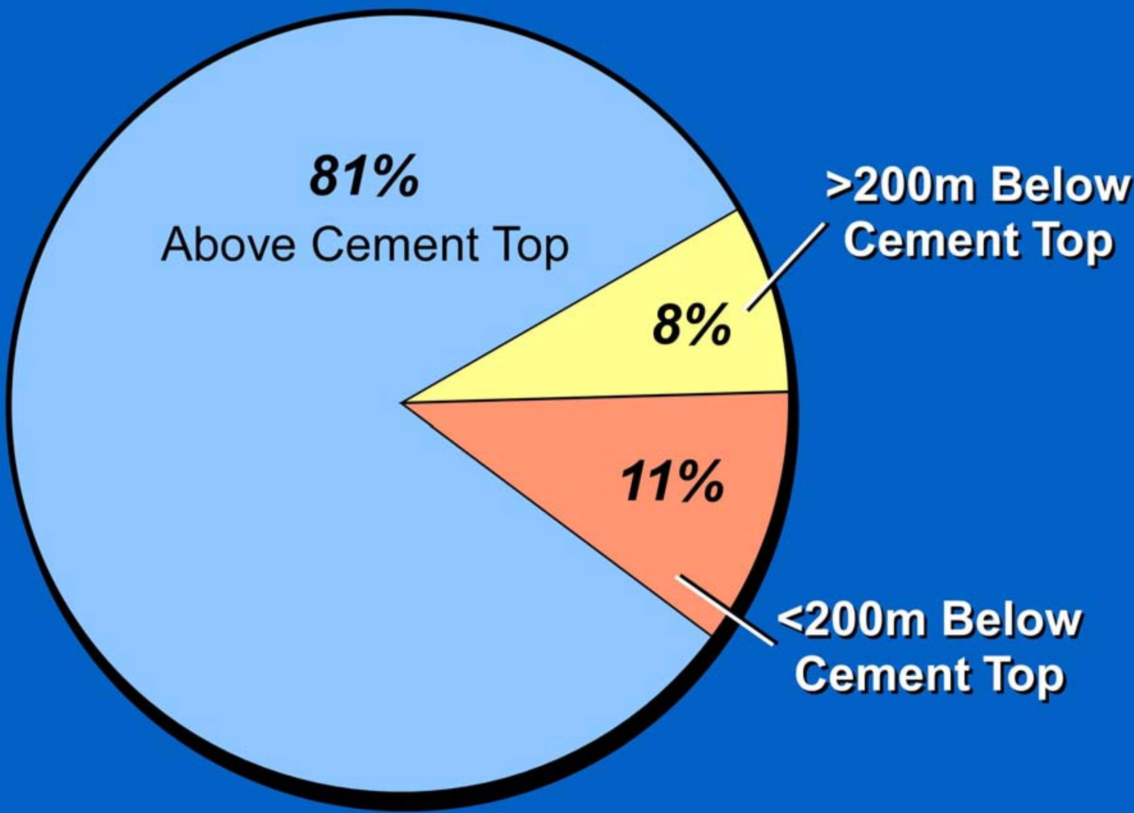
129,773 m logged in 142 wells

External Corrosion versus Cement Quality



10,442 m logged in 142 wells

Location of SCVF/GM Source versus Cement Top



64 wells

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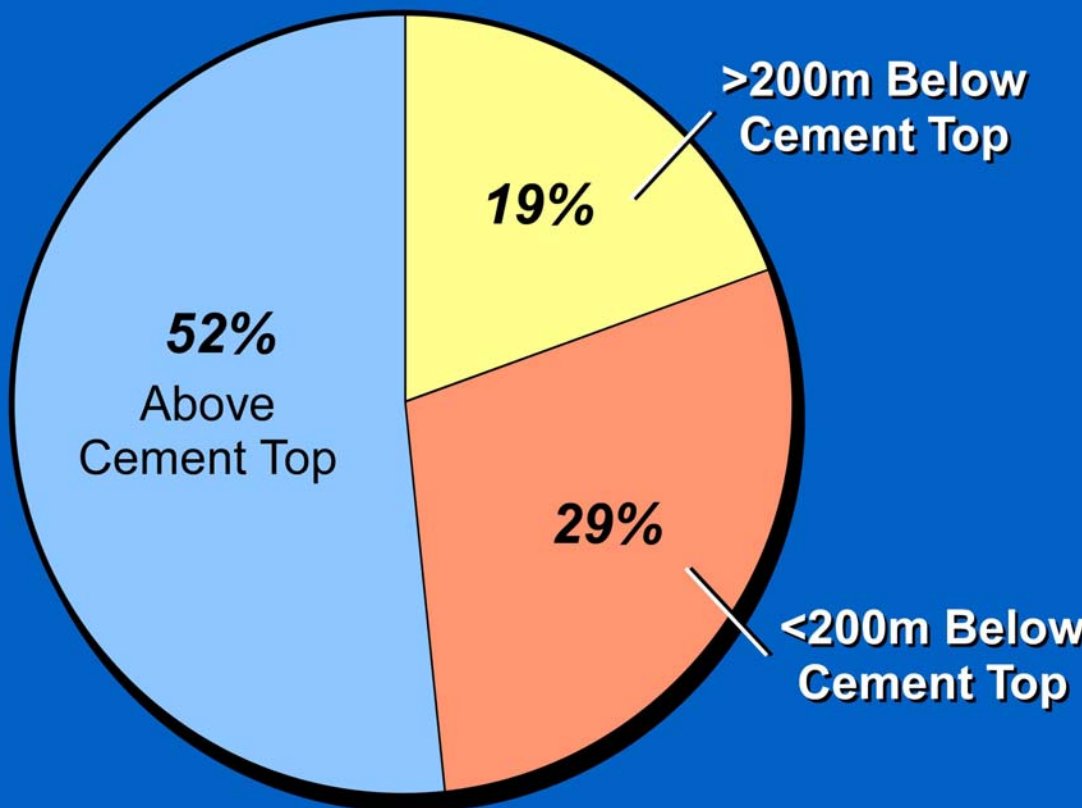
Location of Casing Failure versus Cement Top



64 wells

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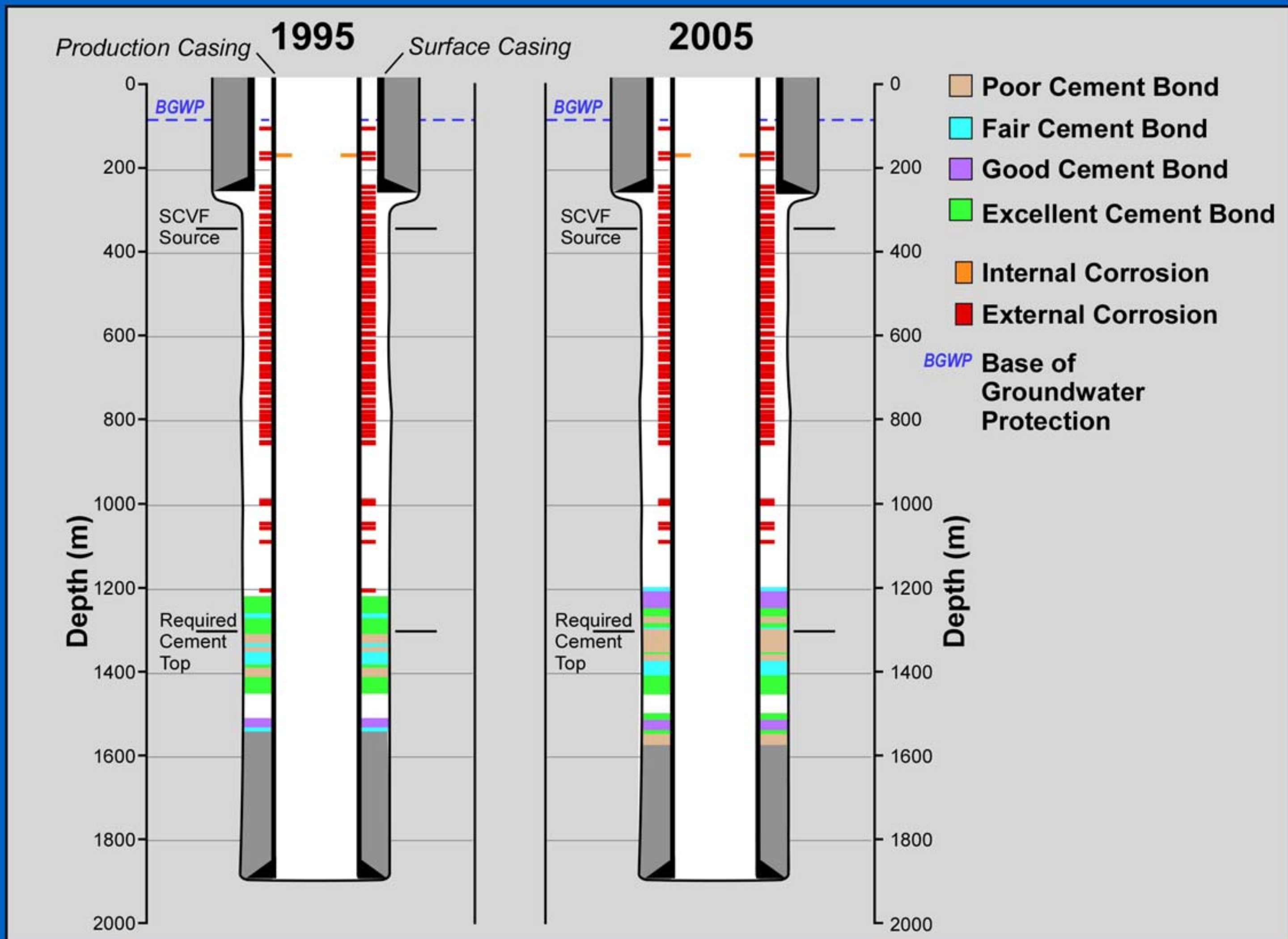
Interpretation of Cement Bond Logs in the Same Well in the Zama Field



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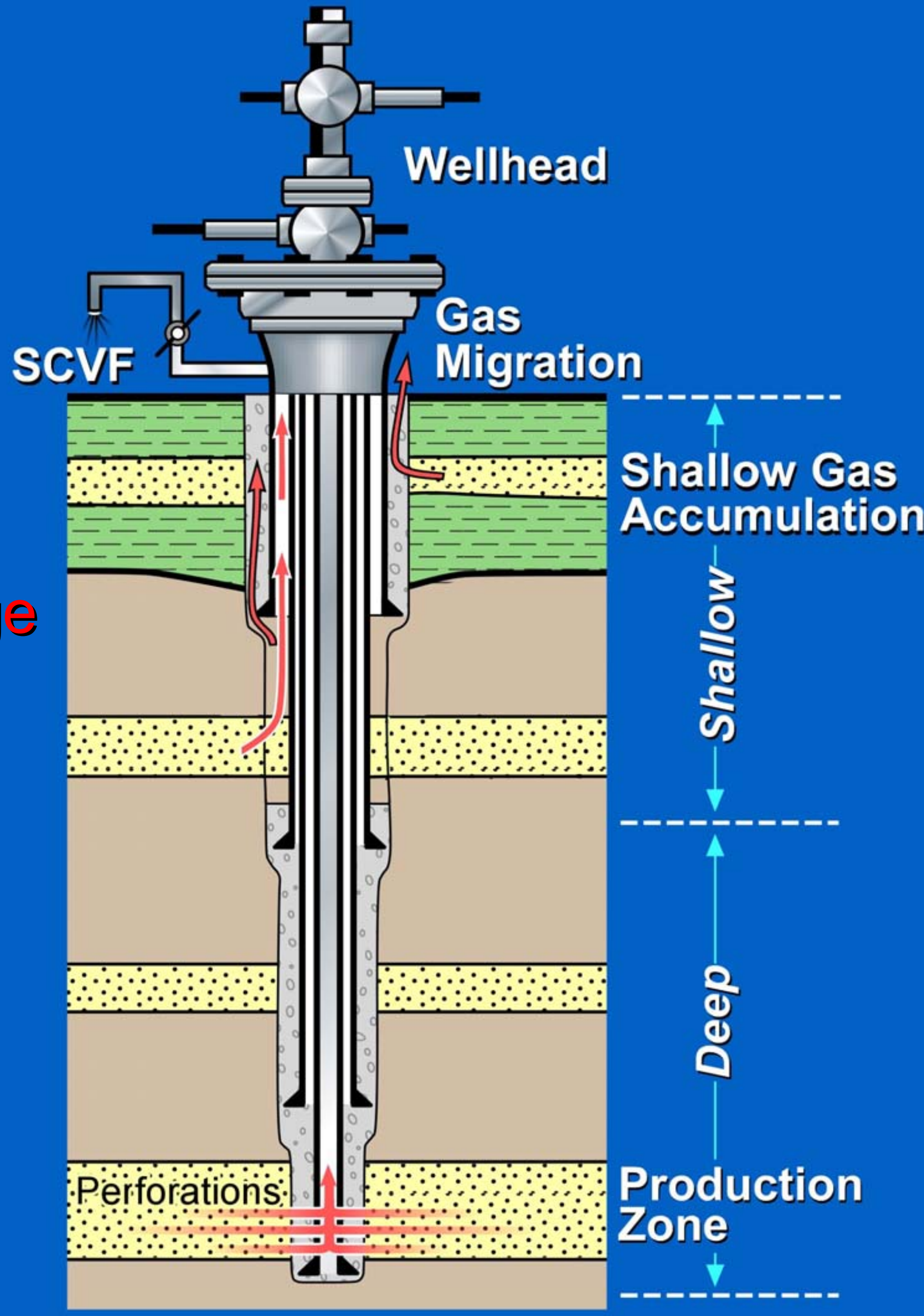
Leakage Potential along a Well

Shallower, upper part

Higher potential for leakage

Deep, lower part completed in producing zones

Less potential for leakage



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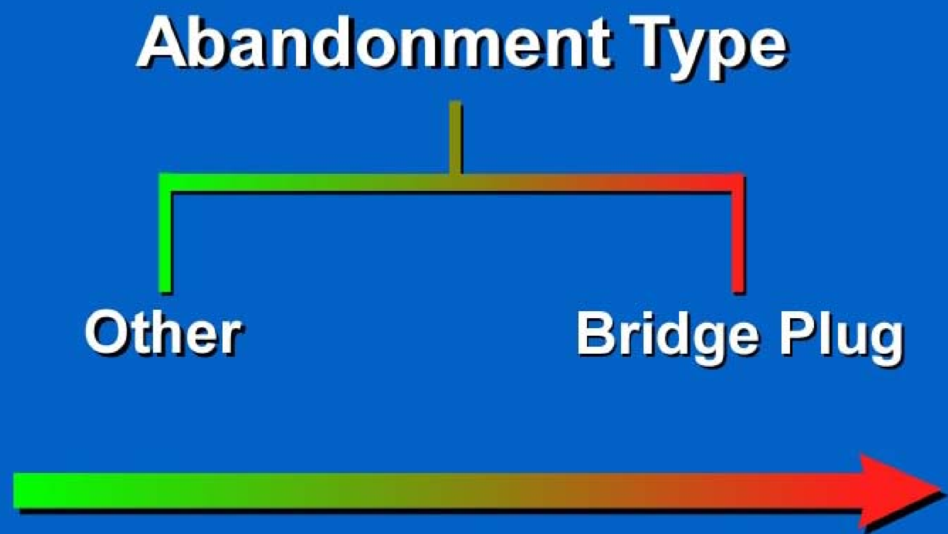
Well Attributes for Leakage Assessment in Alberta

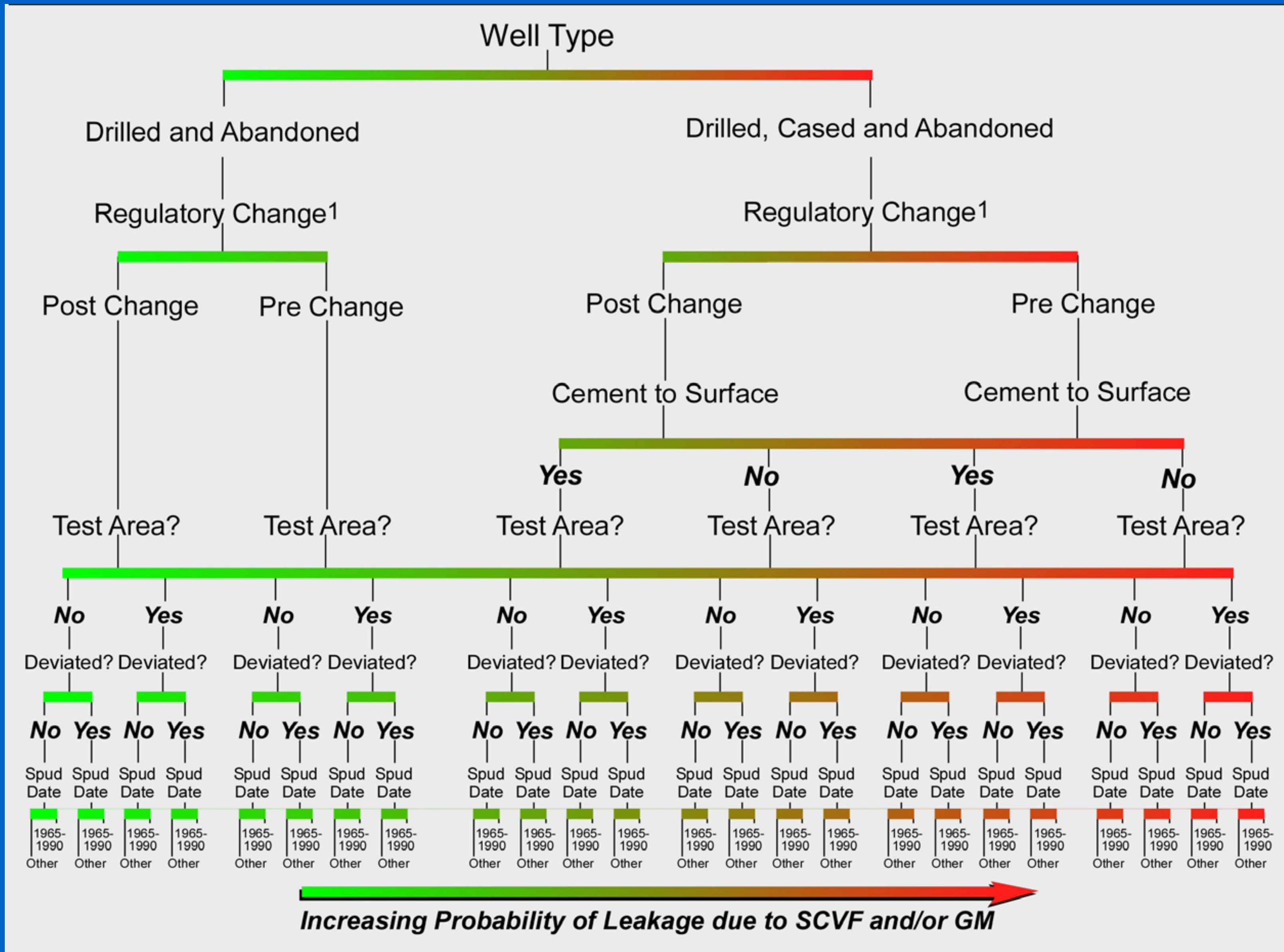
- Type: drilled and abandoned, or cased
- Cementing requirements and practices
- Location (in Test Area or outside)
- Direction: vertical or deviated (including horizontal)
- Time of drilling in relation to economic activity and regulatory changes
- Time of abandonment in relation to regulatory changes

Potential for Well Leakage Inside Production Casing



Increasing Probability of Leakage Inside the Casing

Assessment of the Potential for Well Leakage



Conclusions

- The majority of well leakage is due to time-independent mechanical factors controlled during well drilling, construction or abandonment, mainly cementing

- Uncemented casing is the main factor in SCVF/GM and/or casing failure occurrence

- Good quality cementing will likely protect wells against cement degradation and casing corrosion

- The deep portion of wells is usually well cemented and zonally isolated

- Good and properly-enforced regulations are key in controlling and detecting well leakage

Answer to Question on the First Slide

It is not the CO_2 injection wells that may/will pose a risk, they will be properly constructed and monitored, and, relatively speaking won't be too many.

It is the existing wells that will pose the greater risk!

Bachu and Watson – Possible Indicators for CO_2 Leakage along Wells, GHGT-8, 2006
Watson and Bachu - Factors Affecting or Indicating Potential Wellbore Leakage; SPE Paper 106817, 2007

CO_2 Capture Project

Wellbore Integrity Study

Charles Christopher
Walter Crow
BP Houston

Questions

- What is the magnitude of the problem?
- How are problems detected?
- Remediation methods

A Comprehensive Wellbore Integrity Program

- **Analysis of current well stock**
- **Compilation of historical statistics on effects of CO2**
- **Autopsies of wells in contact with CO2**
  - **Logging analysis as well as sample recovery**
- **Laboratory analysis of recovered cement and tubulars**
- **Laboratory understanding of kinetics and mechanisms of attack**
- **Reactive transport simulation of CO2 attack**
- **Statistical evaluation of large numbers of wells**

CO_2 Capture Project

CO_2 Well Integrity Survey

Objective
- Project the effect of CO2 on the well barrier system and determine mitigation options

Methodology
- Use existing wells to sample and evaluate barrier conditions
- Analyze the samples
- Create simulation to project the future alteration

Status
- First field survey data/samples under evaluation
- Modeling has been progressing independent of well data. Model program details will follow sample analysis results

CO_2 Capture Project

CO_2 Well Integrity Survey

Obligation

- Results will be carefully evaluated
- Nothing will be hidden
- No conclusions/results will be released until they have been thoroughly evaluated

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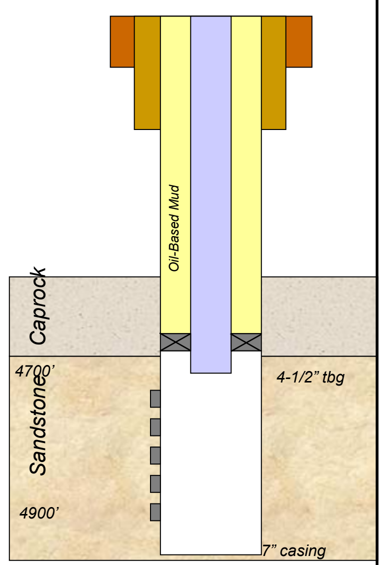
CO_2 Capture Project

Original Well

- Drilled & completed 1976 (deviated well)
- Sandstone formation
- Original test: 10 MMSCF/D (CO_2)
- Tubing change out in 1984 to increase dia. (prior to production)
- No significant corrosion
- Normally pressured reservoir ~0.4 psi/ft
- Water saturation ~20%



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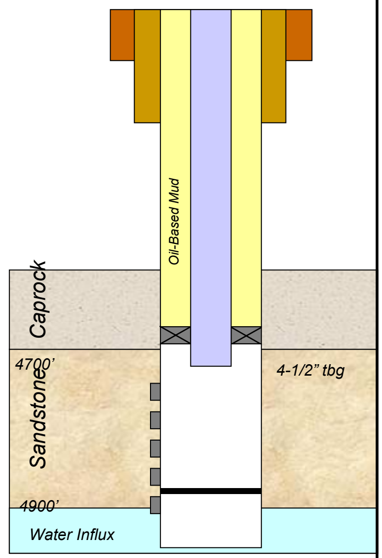
CO_2 Capture Project

Production

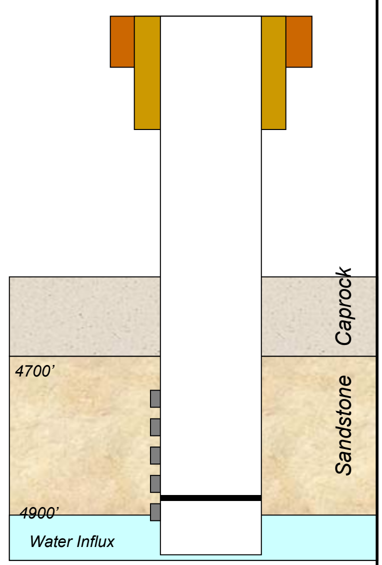
- Initial production 1984
- 1 BBL/MMSCF water production
- Water cut increase in 1997 from lowest zone
- Attempted water shut off - unsuccessful
- Continued production ~1 MMSCF/D CO_2
- Reservoir pressure less than 0.1 psi/ft



CO_2 Capture Project

Well Integrity Survey

- October 2006
- Rig removed tubing and packer
- Acoustic cement evaluation tools
- Casing caliper log
- Pulsed neutron log
- Fluid samples attempted
- Pressure drawdown tests in cement sheath
- Sidewall cores



CO$_2$ Capture Project

Tubing in Good Shape After 22 Years

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CO$_2$ Capture Project

Foundry Stencil Still Visible

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CO_2 Capture Project

Logging Run

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CO_2 Capture Project

Legend

Cement core recovery (red)

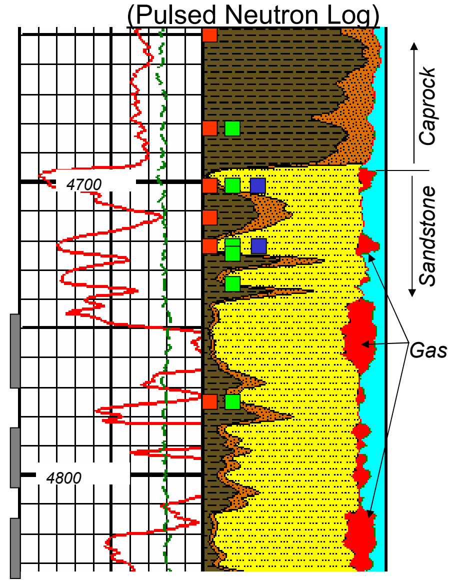
Pressure test cement sheath (green)

Fluid / gas sample (blue)

Recovery Summary

- *6 Cement cores*
- *6 Cement pressure tests*
- *2 Fluid samples*

(Pulsed Neutron Log)



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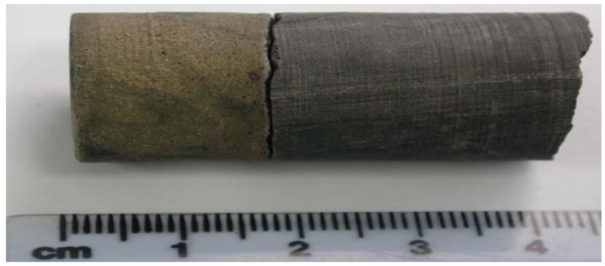
Cement / Caprock Shale



Recovered sidewall cores

Cement

Data and Sample Analysis

- Solids Analysis / Cement Cores (Los Alamos)
  - Xray diffraction
  - Scanning Electron Microscope
- Fluid/gas analysis (SLB - Oilphase)
  - Gas-Water ratio
  - pH
  - Total dissolved solids
  - Elemental analysis
- Log Analysis (SLB)
  - Permeability measurement from drawdown tests
  - Cement evaluation (bonding / gas or fluid cut)
  - Casing corrosion

Modeling / Simulation

- Reaction kinetics (lab and field may be different)
- Depiction of well condition
- History match of well condition
- Well forward simulation
- Engineering solutions for remediation, monitoring & surveillance

CO_2 Capture Project

A Comprehensive Wellbore Integrity Program - Status

- **Analysis of current well stock – In Design**
- **Compilation of historical statistics on effects of CO2 – In Design**
- **Autopsies of wells in contact with CO2 – In Progress**
  - **Logging analysis as well as sample recovery**
- **Laboratory analysis of recovered cement and tubulars – In Progress**
- **Laboratory understanding of kinetics and mechanisms of attack - Continuing**
- **Reactive transport simulation of CO2 attack – In Design**
- **Statistical evaluation of large numbers of wells – In Progress**

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CO_2 Capture Project

More to come…………

Analysis of abandoned well integrity at a potential CO_2 storage site

3rd Well Bore Integrity Network Meeting, March 12-13 2007, Santa Fe, USA

TNO | Knowledge for business

Frans Mulders

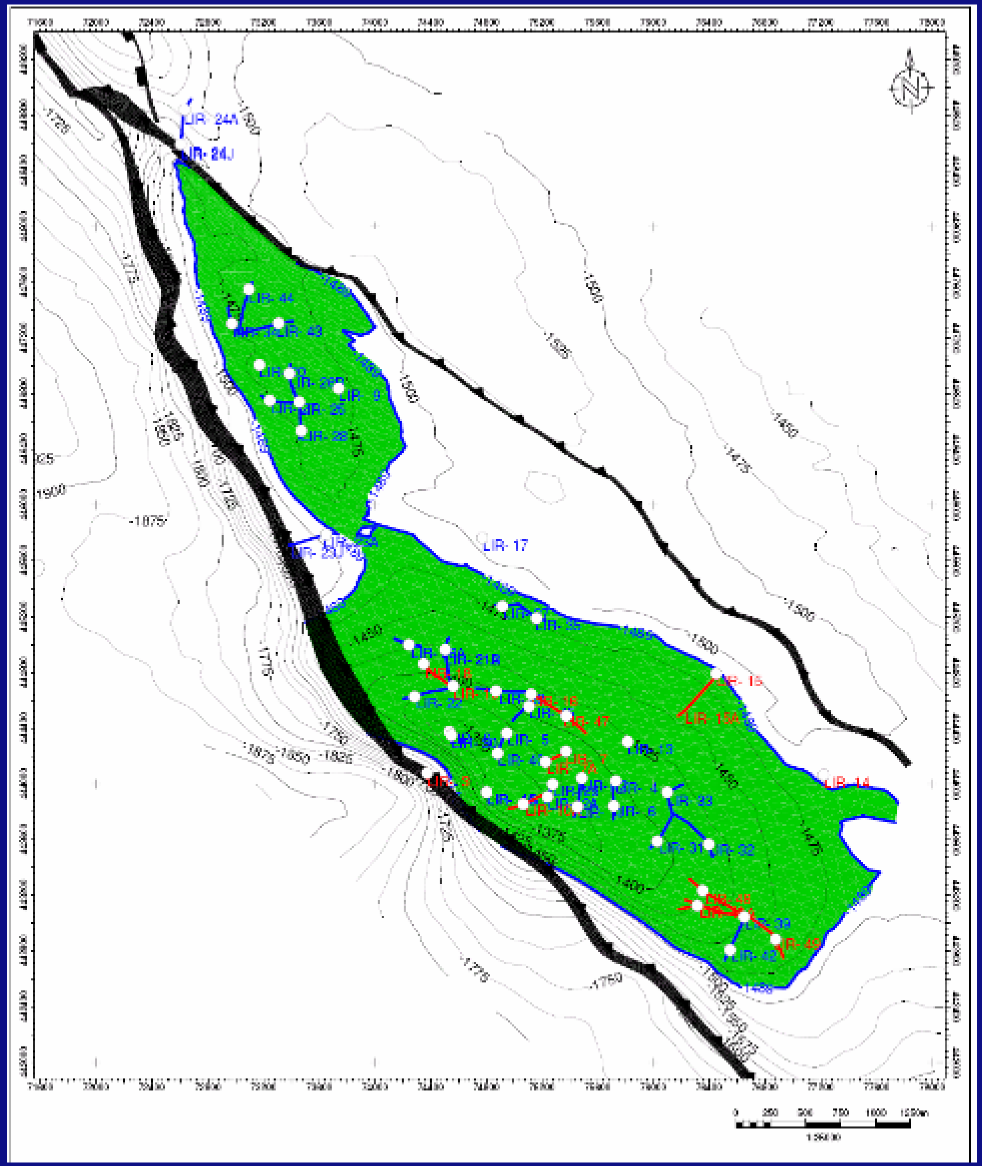
Introduction

Purpose of study:

- Study integrity of abandoned wells at an onshore potential CO_2 storage site

Topics addressed:

- Identify possible leakage mechanisms
- Identify possible leakage pathways
- Dutch Mining Law



The questions we had

Main question:

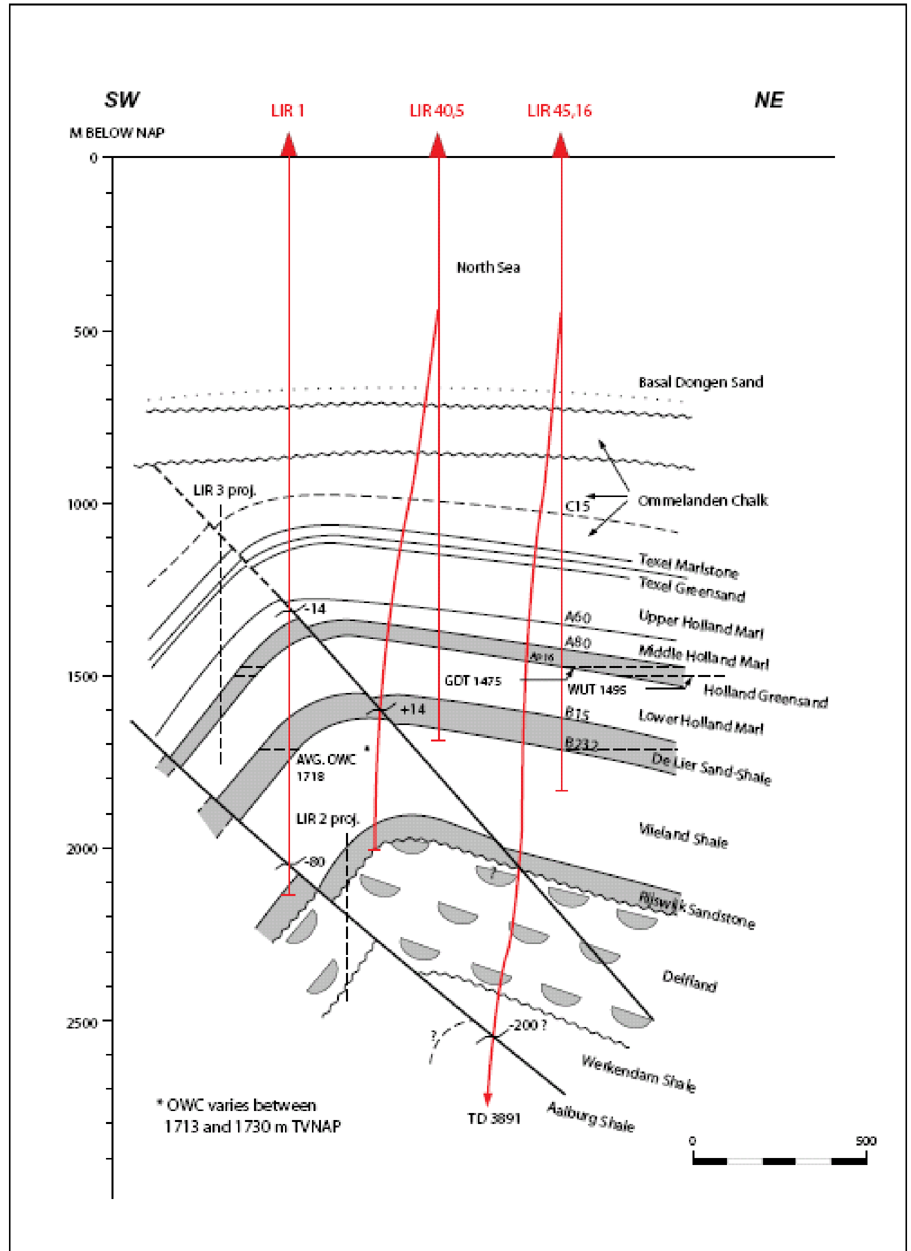
- How fast can CO_2 leak how far up in the well?

Subquestions:

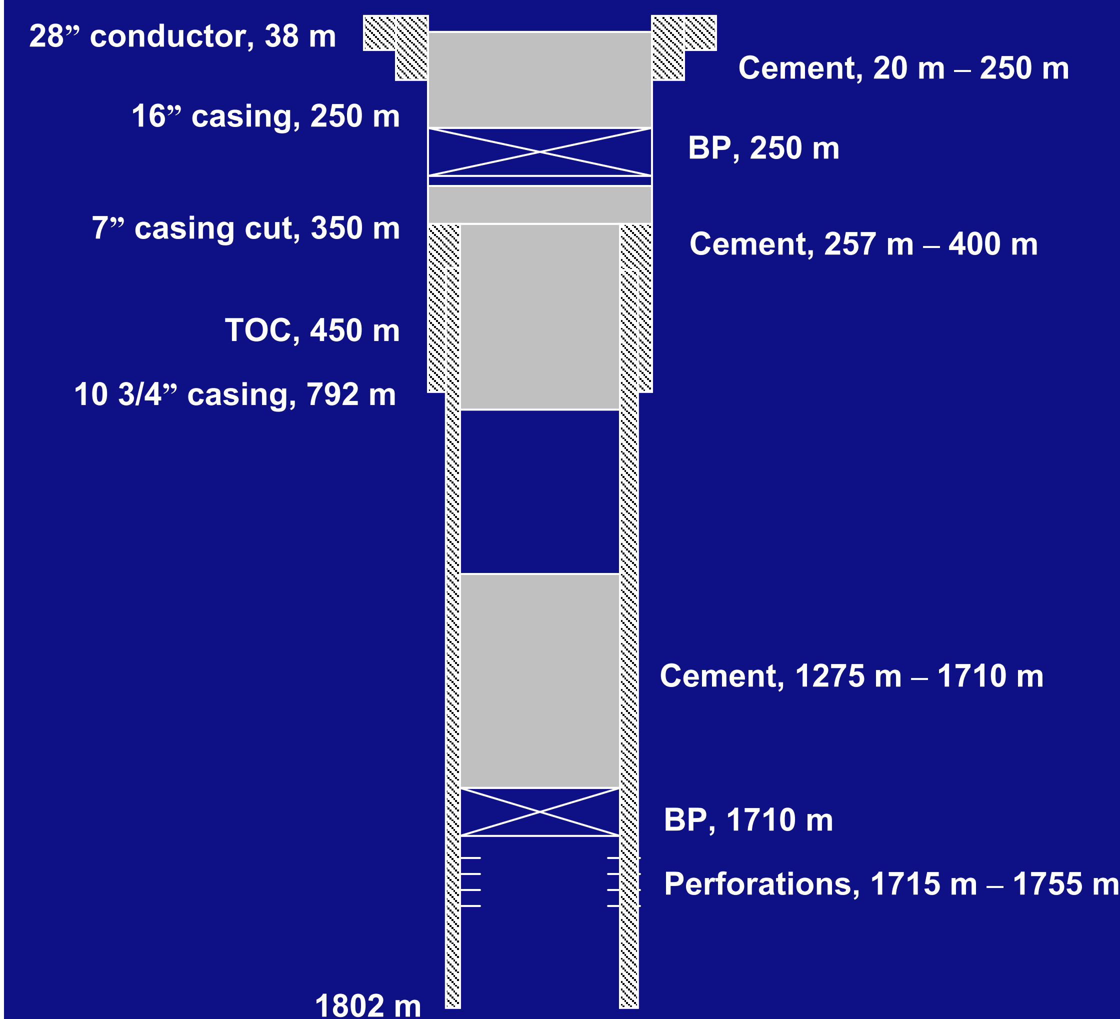
- Geometry of the wells?
- Corrosion?
- Mechanical integrity?

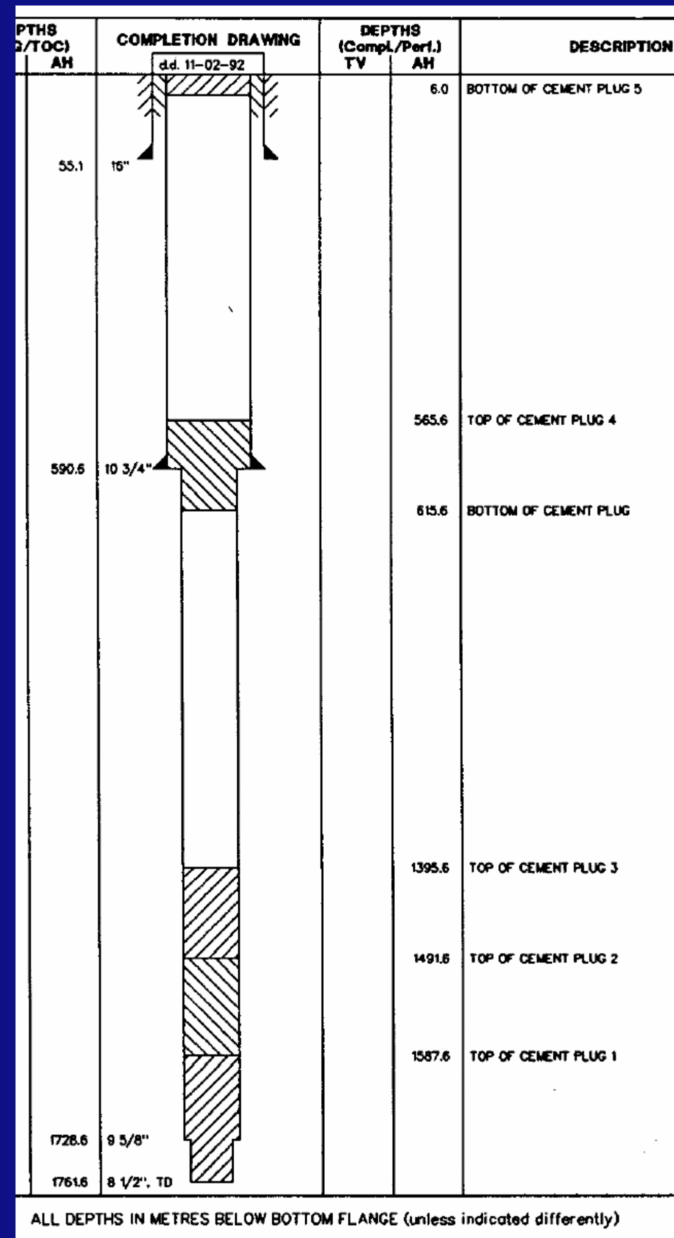
What do the wells look like?

- Stacked reservoir
- Most wells completed in lower oil stack
- Abandonments according to Dutch Mining Law
- CO_2 injection in shallower depleted gas stack

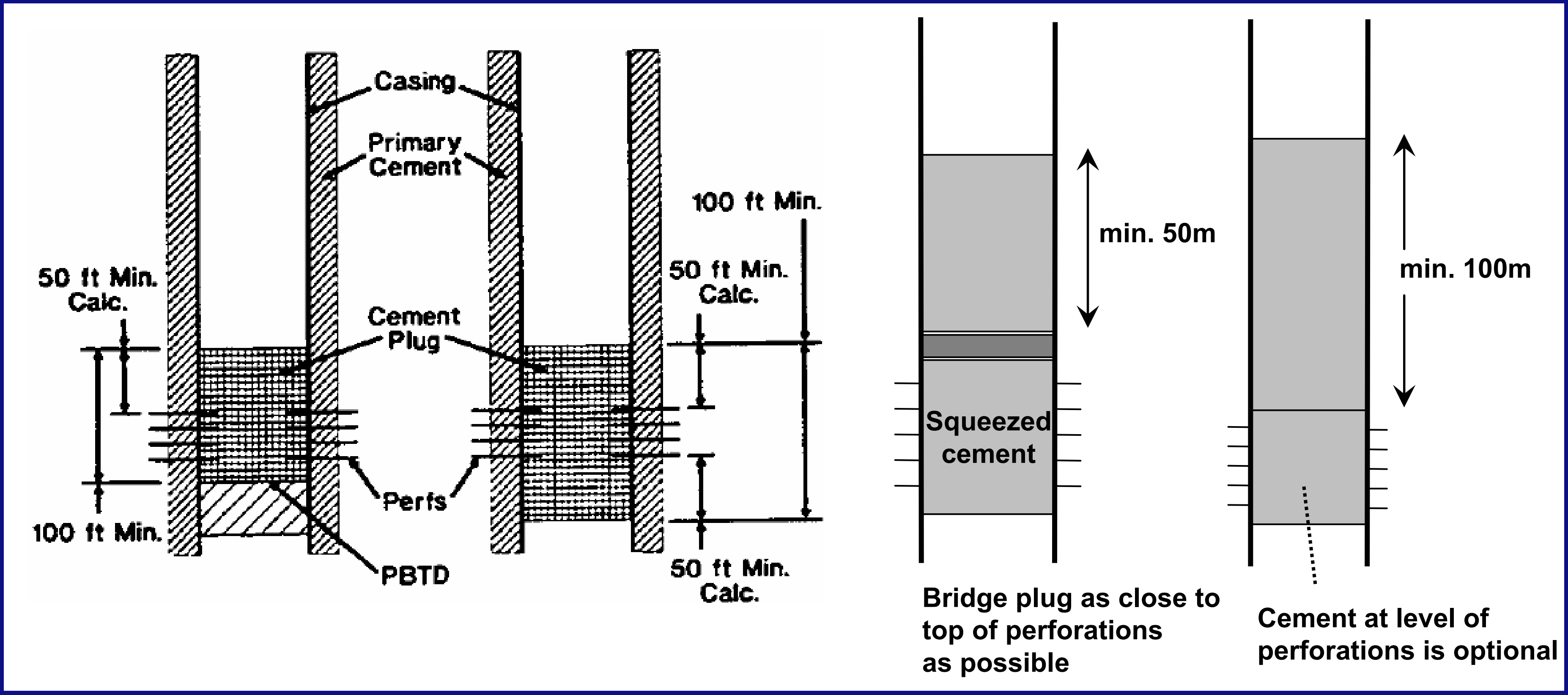


Examples of wells

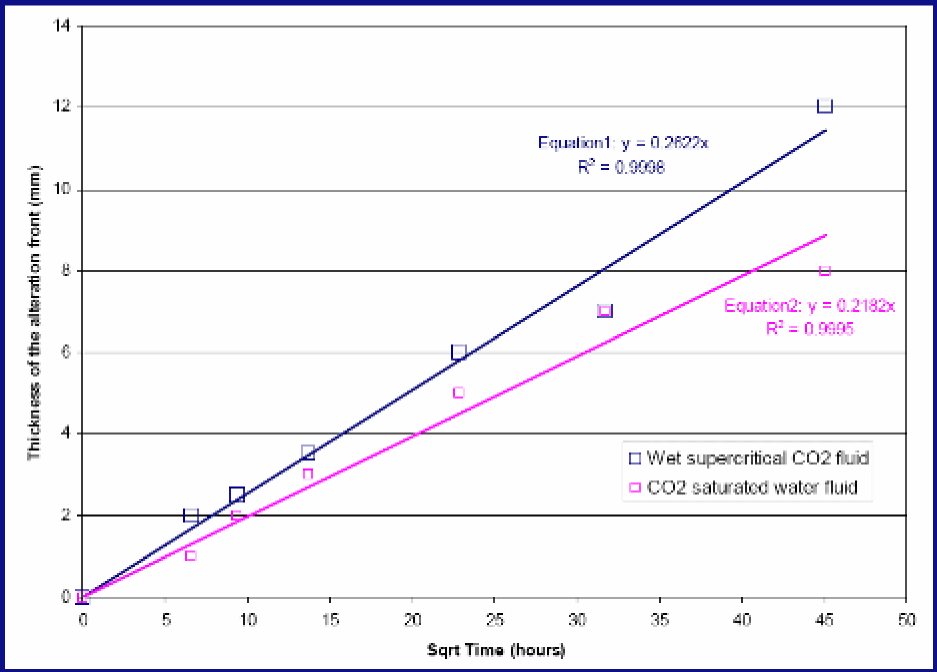


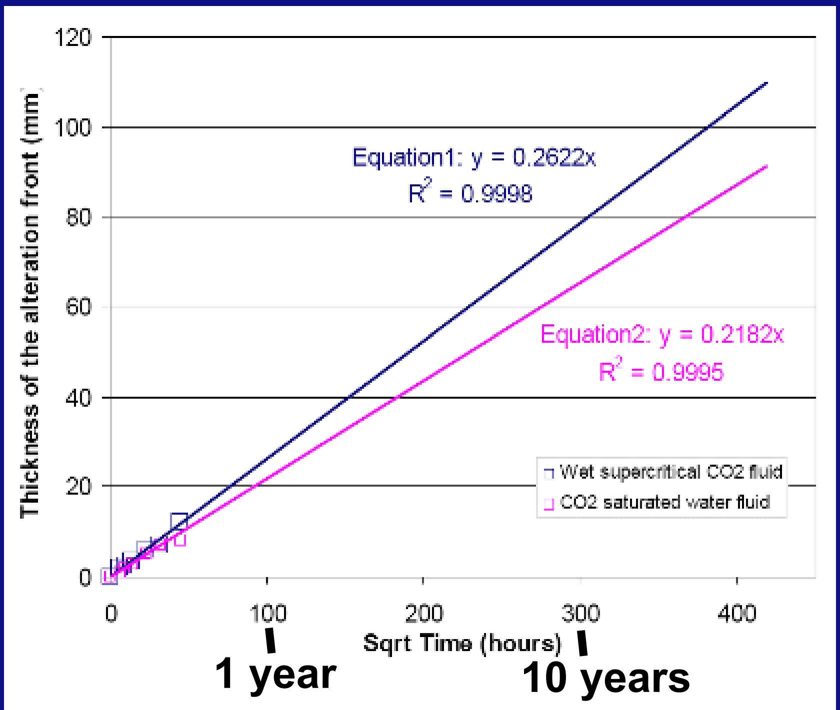


Cement plug lengths according to Dutch Mining Law



Chemical degradation of Portland cement





Source: Barlet-Gouedard *et al.* 2006

Watersaturated supercritical CO_2 fluid: $$d[mm] = 0.2622 \cdot \sqrt{t[h]}$$

CO_2 saturated water fluid: $$d[mm] = 0.2182 \cdot \sqrt{t[h]}$$

Chemical degradation of Portland cement

Extrapolated from Barlet-Gouedard *et al.* (2006):

Plug length	Corrosion time (years)	
	Wet supercritical CO_2	CO_2-saturated water fluid
1 inch = 2.54 cm (primary cement sheath)	1.1	1.5
6 m (smallest plug length)	60,000	86,000
10 m	170,000	240,000
50 ft = 15.24 m	390,000	560,000
100 ft = 30.48 m	1,500,000	2,200,000
50 m	4,100,000	6,000,000
100 m	17,000,000	24,000,000

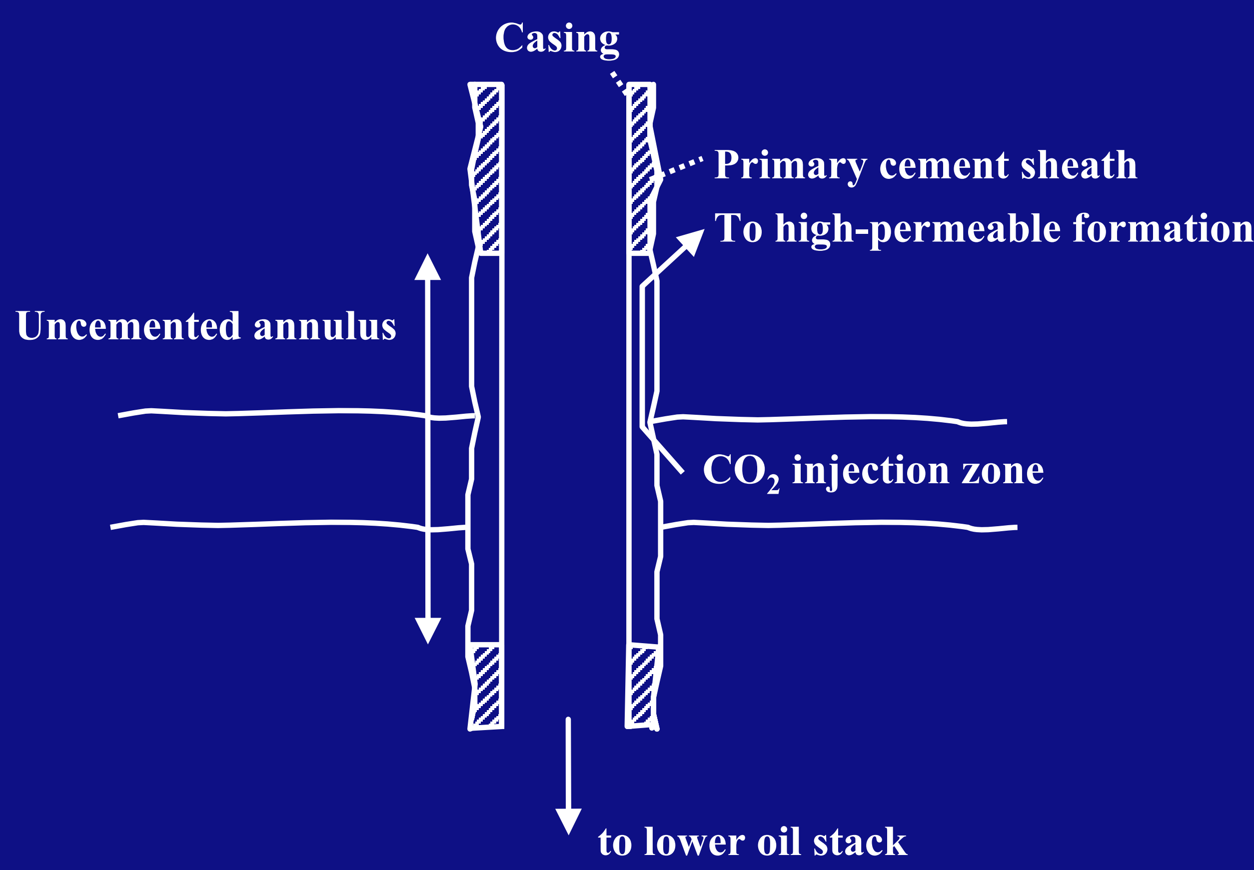
All plugs were pressure tested according to DML standards

Cement plug testing as prescribed by Dutch Mining Law

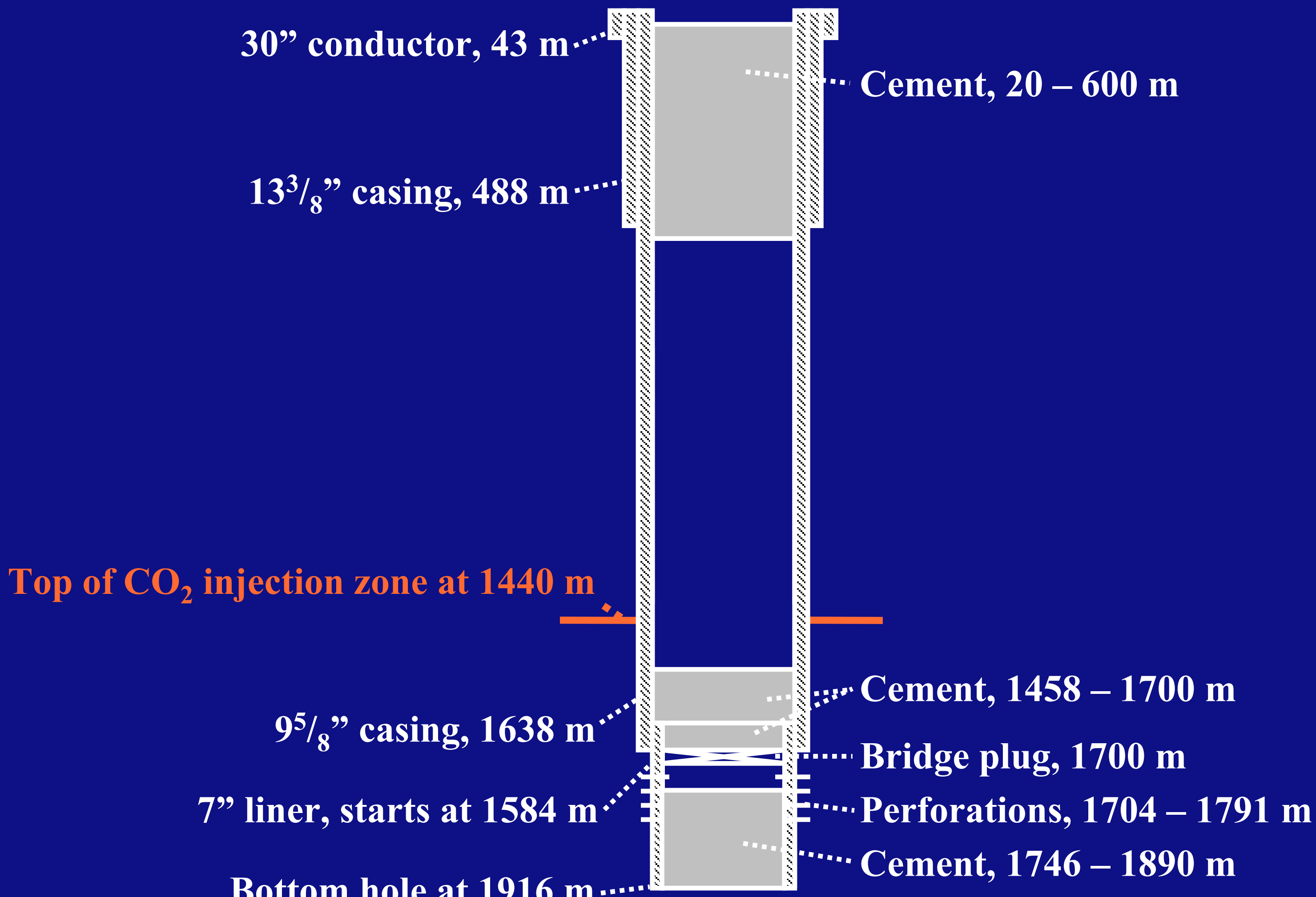
DML requires a cement plug to be tested
by passing at least one of the following tests successfully:

- Weight test of at least 100 kN
- Pressure test of at least 50 bars during 15 minutes
- Inflow testing the well and verification that no fluid or gas flows from the reservoir into the well

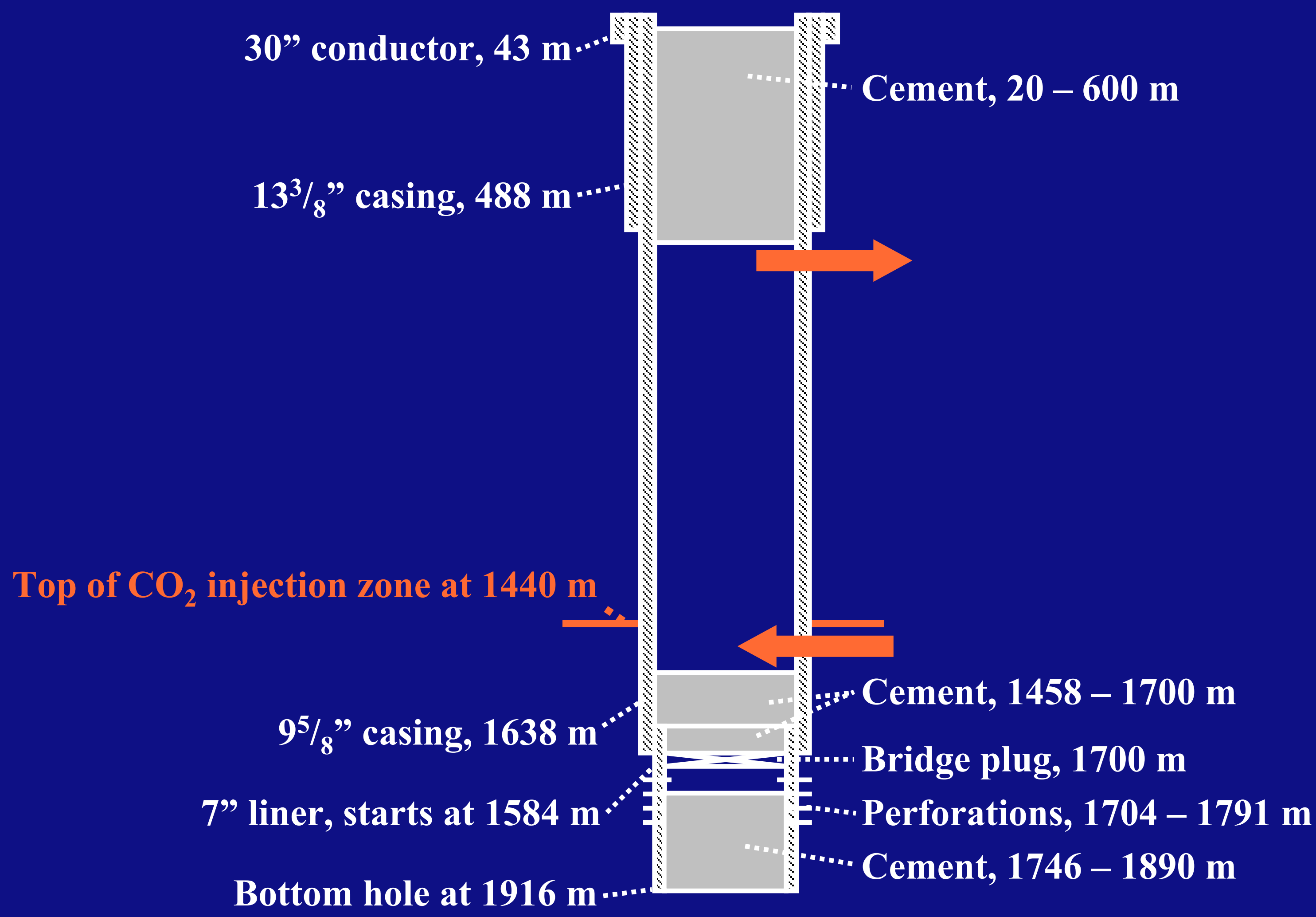
Two main concerns: the first



Two main concerns: the second



Questions: corrosion and leakage rates?



Resources used for rough corrosion rate estimation in radial well direction

Cement (1 inch)

• Barlet-Gouedard et al. (2006)	> 1 year
• Duguid et al. (2006)	< 700 years
• Duguid et al. (2004)	~ 60 – 110 years

Casing

• De Waard & Lotz (1993)	< 20 mm / year
• Carvalho et al. (2005)	~ 0.3 – 0.9 mm / year
• Cui et al. (2004)	< 30 – 2.5 mm / year
• George (2003)	< 6.3 mm / year

Technical conclusions of the study

- Chemical degradation of cement abandonment plugs based on diffusion seems too slow to be an issue, unless fractures or other pathways through the cement are present or induced
- For the studied case, radial corrosion of the primary cement sheath and casing appeared to be the main issue
- The corrosion rates of cement and casing under the prevailing conditions could only be very roughly assessed; corrosion of primary cement sheath and casing might be in the order of decades under the prevailing conditions (p = 150 bar, T = 57^{o}C, pH = 4 – 5)
- Induced stress changes and deformations in the reservoir are too low to cause serious well damage. In the worst case they could enhance corrosion rates

Conclusion operator

- The operating company decided not to conduct the project and is looking now at other cases with control on abandonment

Recommendations

- Requirements / guidelines for already abandoned wells do not specifically consider re-use of the subsurface for CO_2 storage, i.e. abandonment might not be compatible with CO_2.
- The current philosophy of well design and abandonment should consider application for future CO_2 storage. Joint effort of operators and regulators is required.

Practical questions

- How do the following effects speed up / slow down corrosion rates of primary cement sheath and casing?
  - Reservoir formation (limited reaction surface)
  - pH development in reservoir over time
  - Supply rate of CO_2
  - Connate instead of free water
  - Solubility of reaction products
  - Limited transportation possibilities of reaction products
  - Pressure & temperature effects at in-situ conditions
- Once cement and casing have been corroded: How do bulk permeabilities change and affect CO_2 leakage rates?
- To what extent are vertical fractures and other vertical pathways adjacent to cement self-healing by carbonation and limited CO_2 supply?

3rd Wellbore Integrity Network Meeting

Role of Permanent Downhole Integrated Instrumentation Systems in Assessing Wellbore Performance - Penn West CO2-EOR Monitoring Project

Rick Chalaturnyk

Geological Storage Research Group
Department of Civil and Environmental Engineering
University of Alberta

12th – 13th March 2007
La Fonda Hotel,
Santa Fe, New Mexico, USA

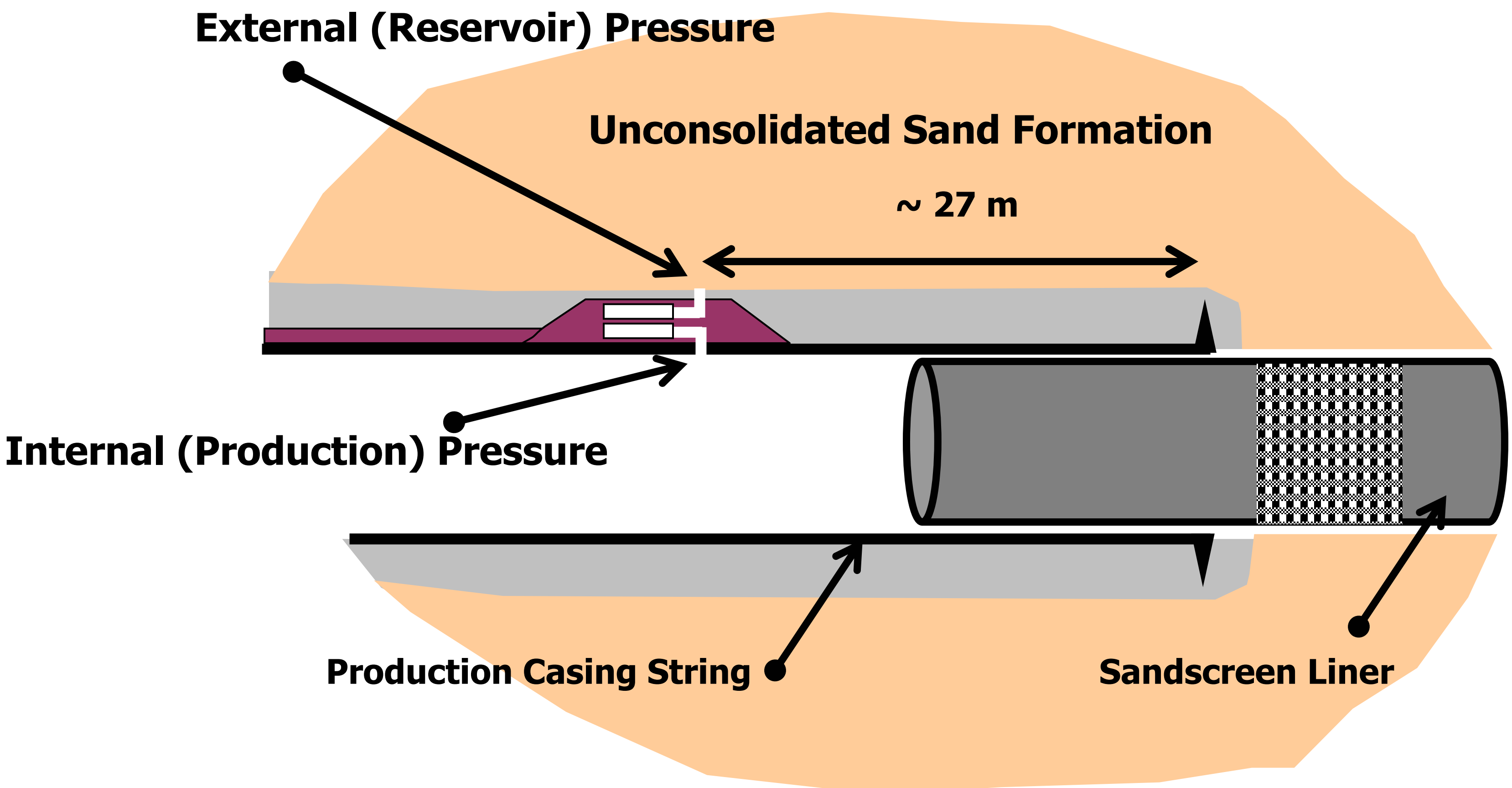
Outline

- Two Case Histories on Deployment of Permanent Downhole Well-Based Monitoring Systems
- Summary

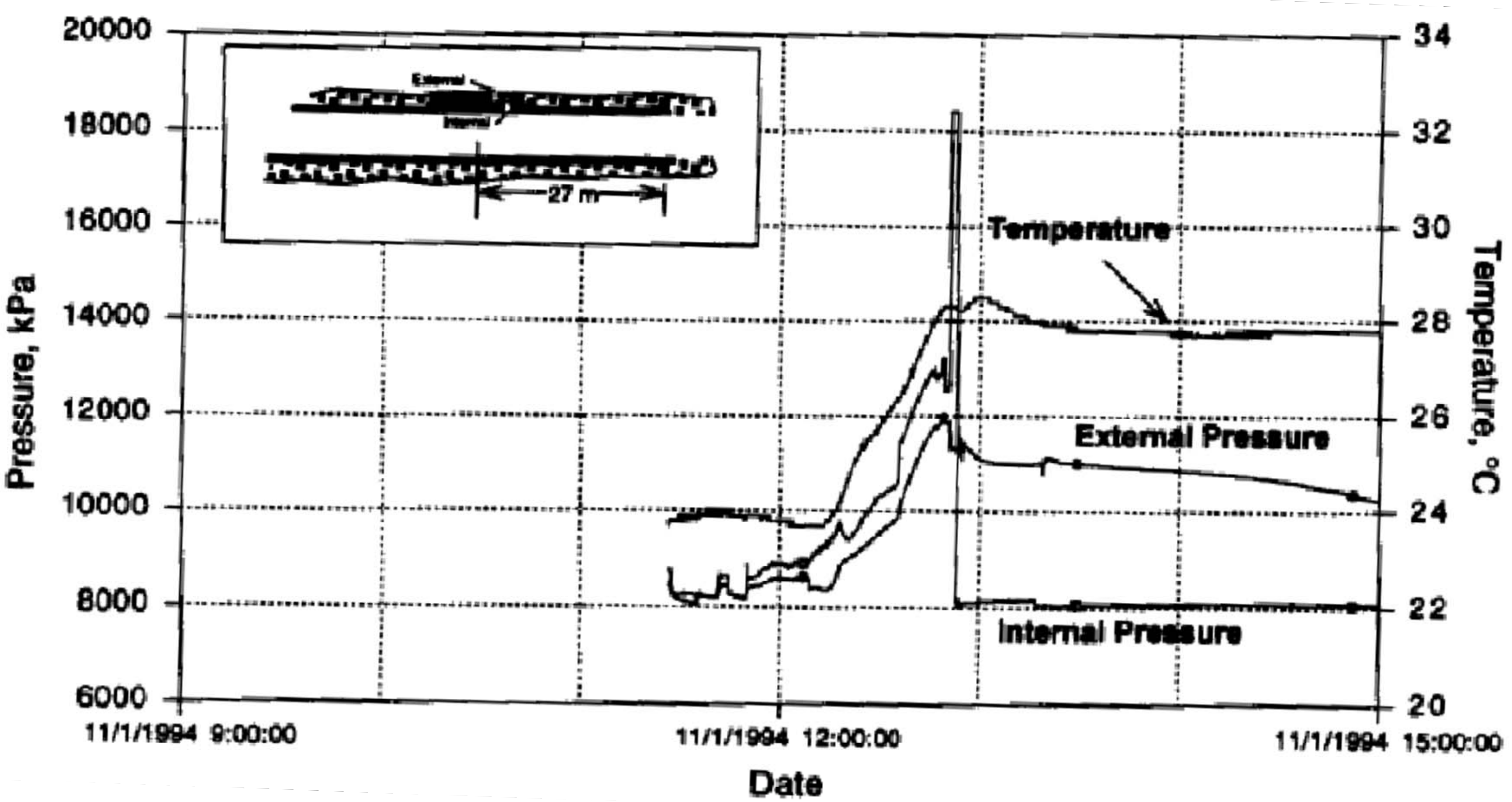
Casing Conveyed System

- Casing Conveyed pressure and temperature gauges for reservoir and bottomhole measurements
- Integrated permanent installation of geophones, pressure/temp gauges and downhole fluid sampling ports

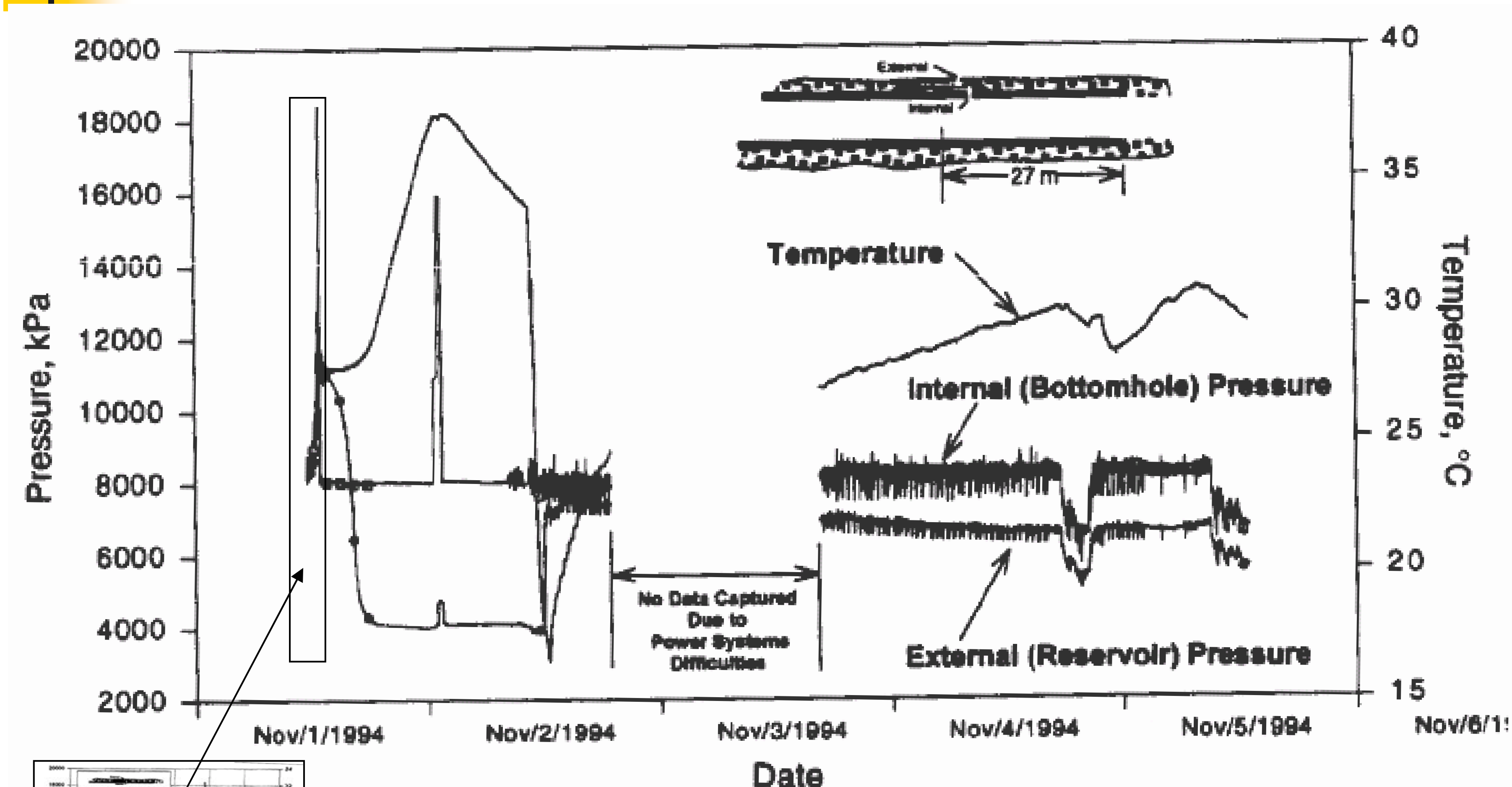
Casing Conveyed Pressure and Temperature Gauges

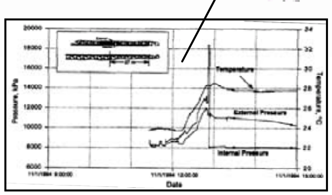


Pressures during Installation and Cementing

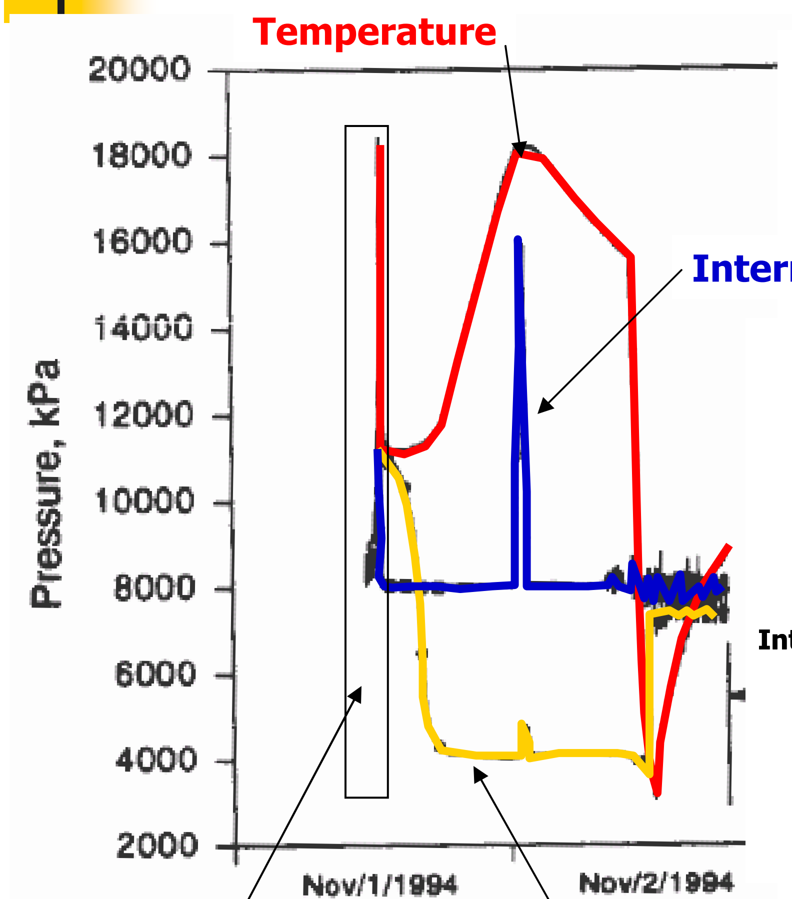


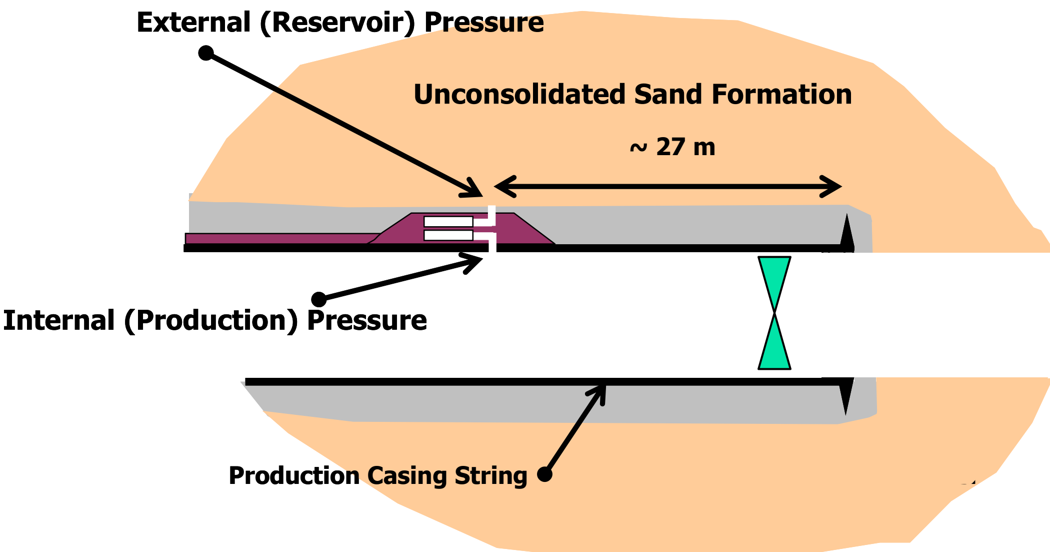
Response during Cement Hydration and Drilling of Horz.

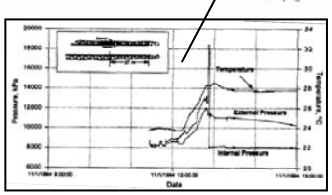




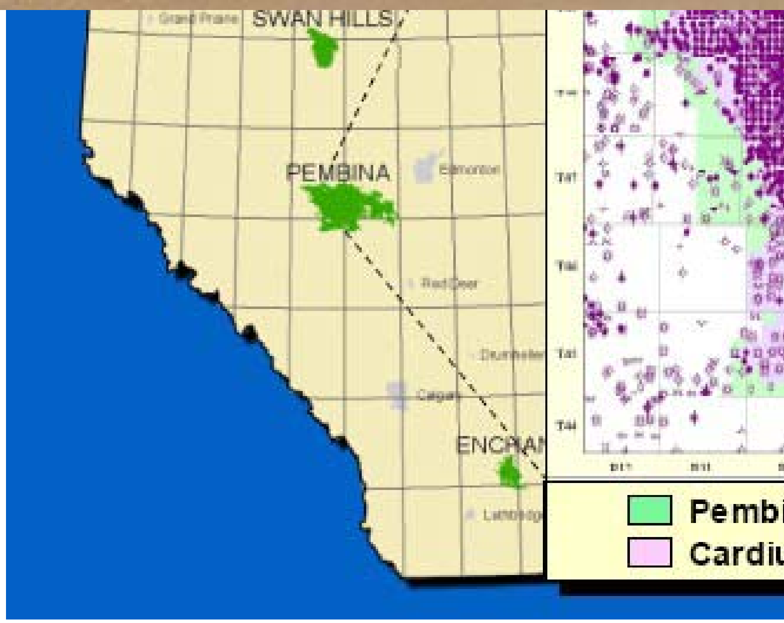
Response during Cement Hydration and Drilling of Horz.



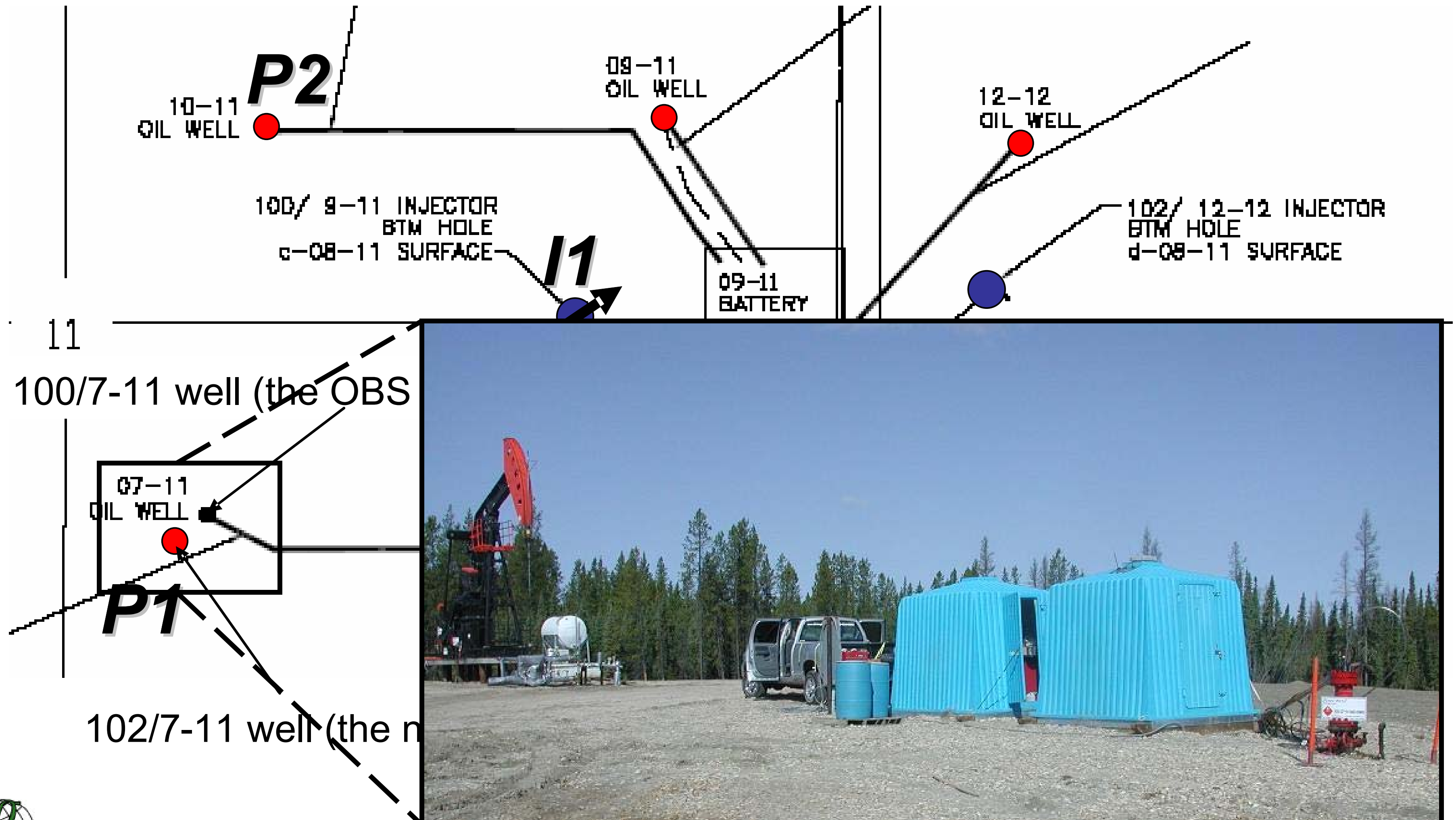




Penn West CO_2-EOR Pilot



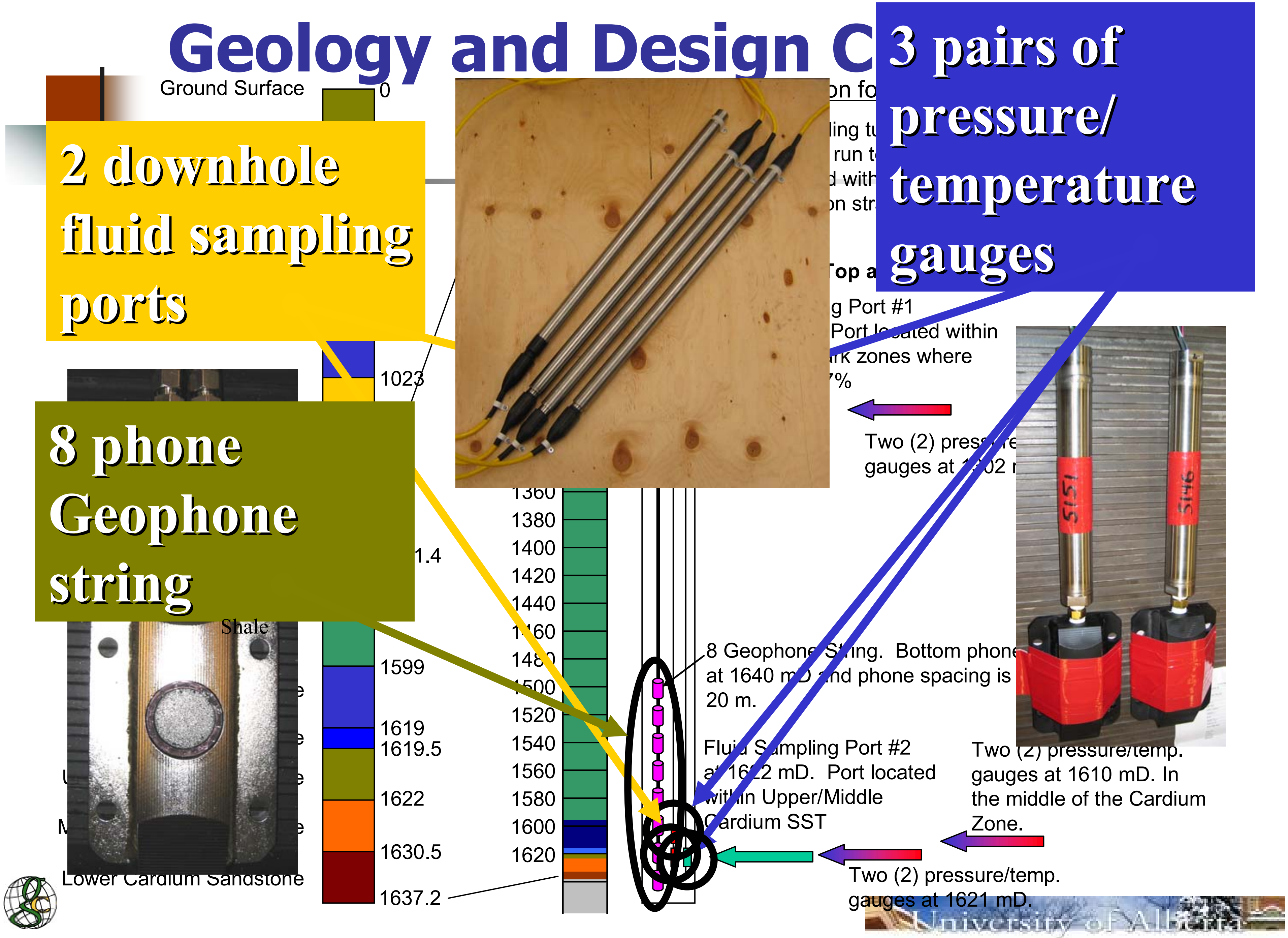
Pennwest CO2-EOR Pilot
6 Producers, and 2 injectors

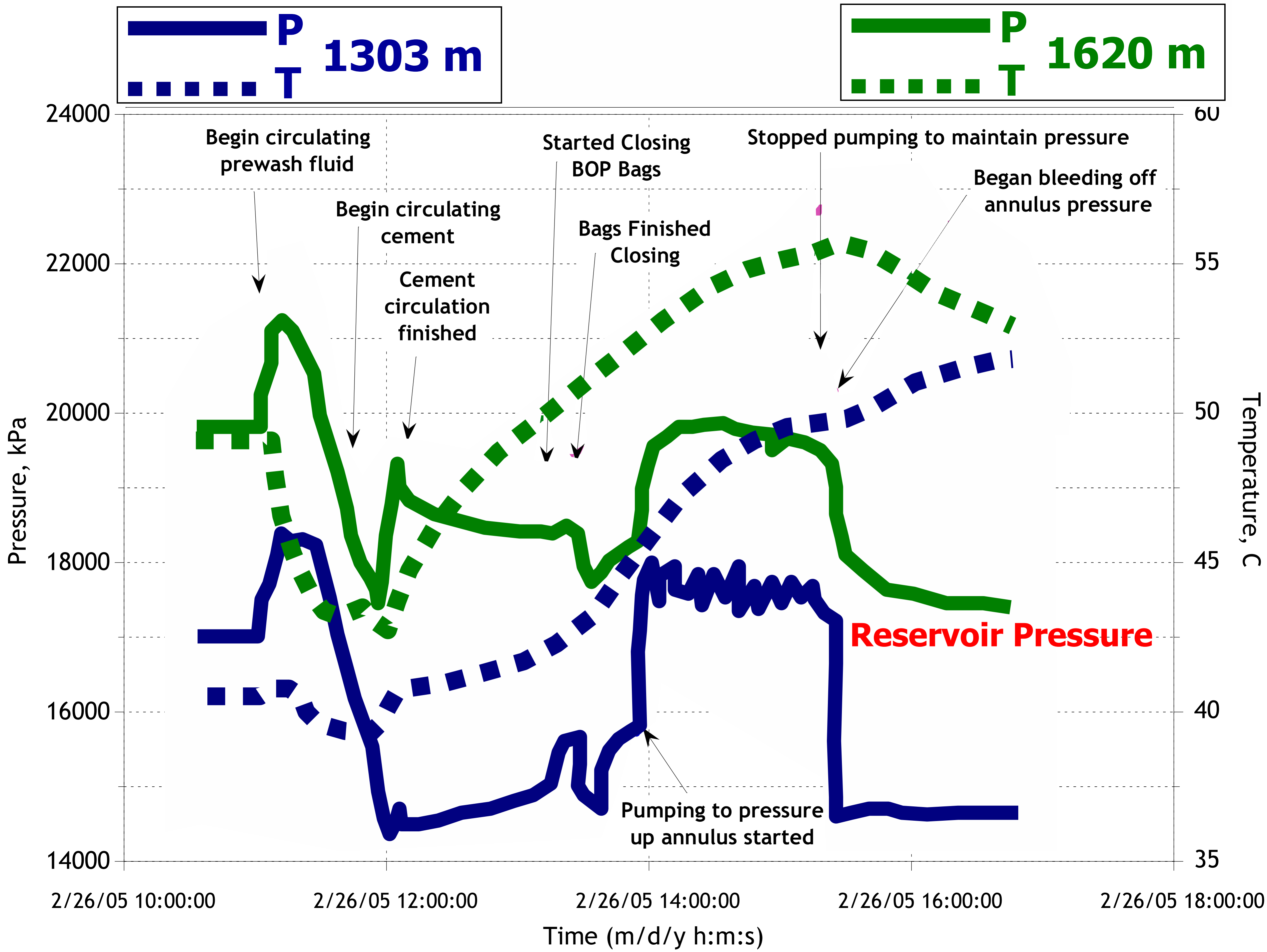


Observation Well Specifications

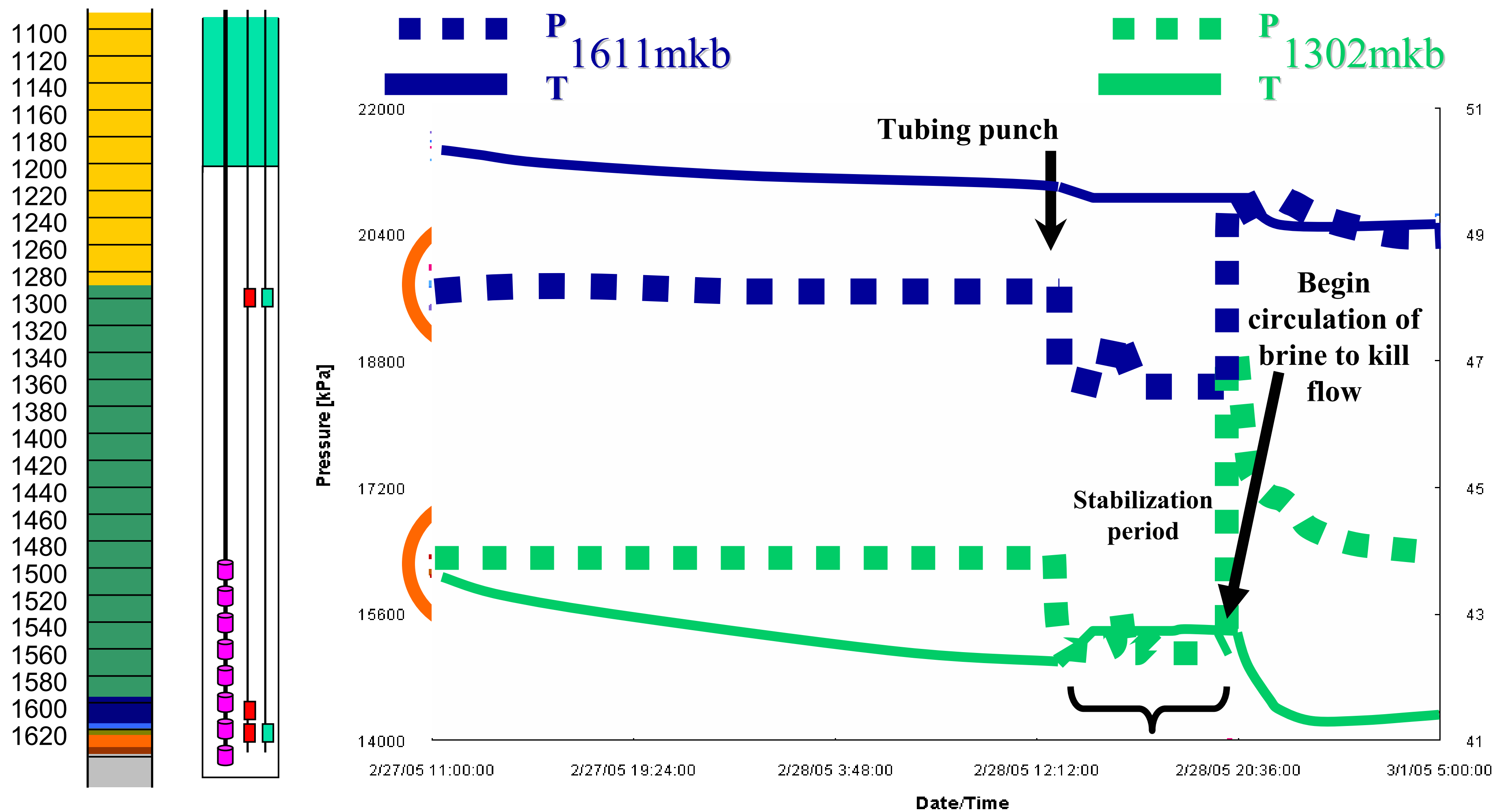
Well depth:	1600 m (5250 ft)
Casing:	139.7 mm (5.5 in) @ 25.3 kg/m
BHP:	approximately 19 MPa (2700 psi)
BHT:	approximately 50°C (122 °F)
Deviation:	none (vertical well)
Other:	well is sweet

Geology and Design C




P
T
1303 m
P
T
1620 m
24000
22000
20000
18000
16000
14000
60
55
50
45
40
35
Pressure, kPa
Temperature, C
Begin circulating prewash fluid
Begin circulating cement
Cement circulation finished
Started Closing BOP Bags
Bags Finished Closing
Stopped pumping to maintain pressure
Began bleeding off annulus pressure
Reservoir Pressure
Pumping to pressure up annulus started
2/26/05 10:00:00
2/26/05 12:00:00
2/26/05 14:00:00
2/26/05 16:00:00
2/26/05 18:00:00
Time (m/d/y h:m:s)

Wellbore Completion
Feb 27 to Mar 1



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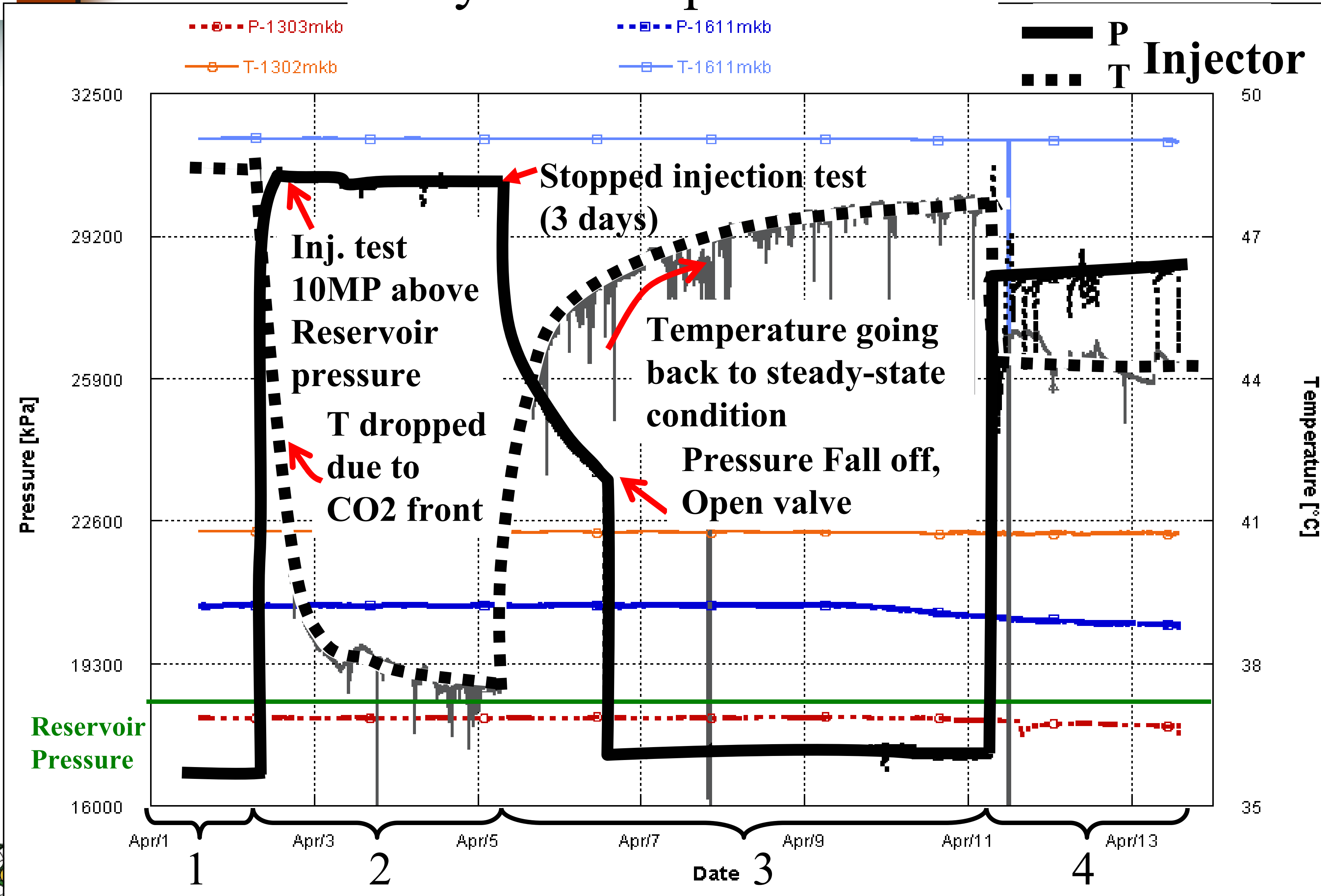
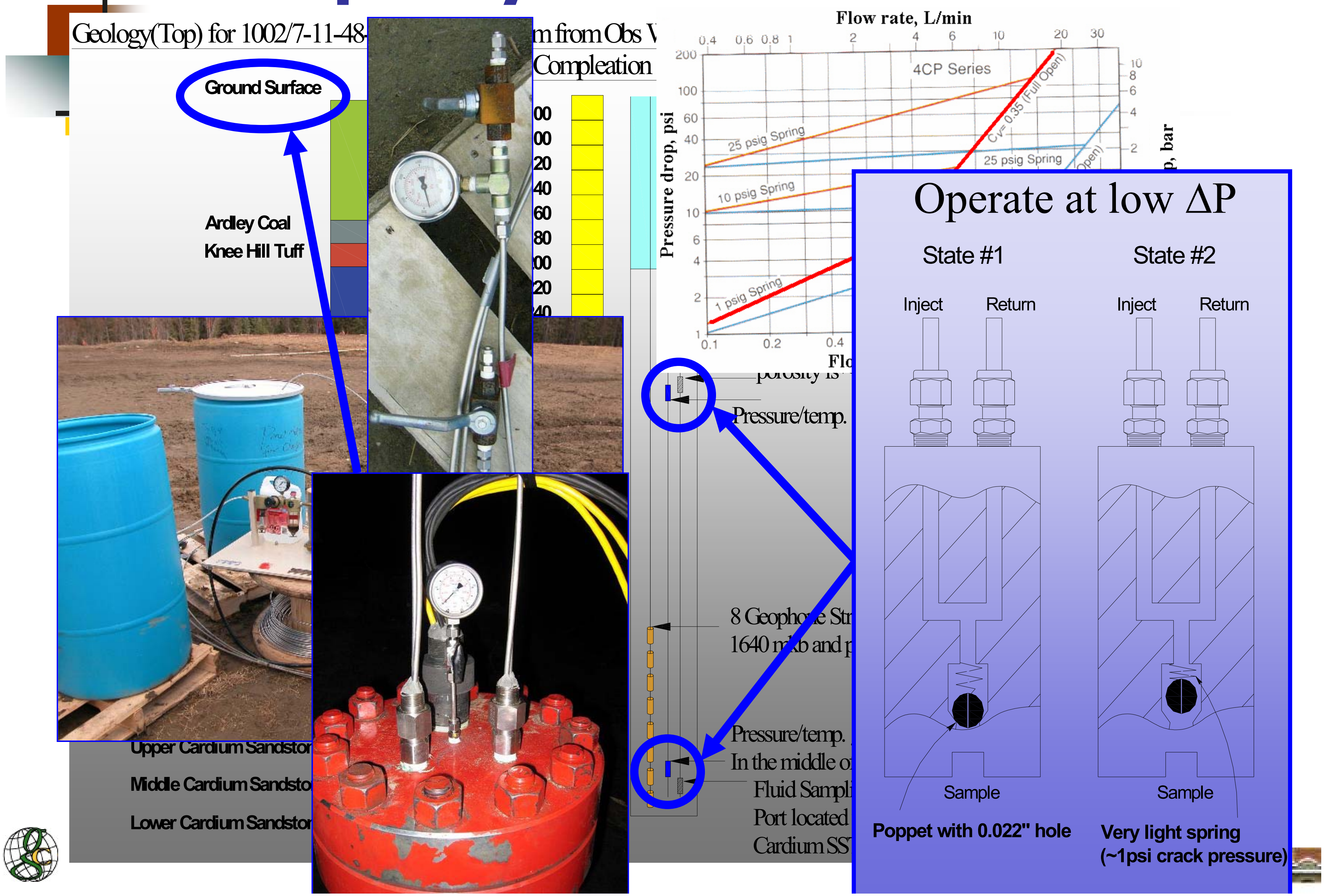
HYDRIL
DANGER
TELLUS T22

Early PT reading in Observation and Injection W

4. System on production

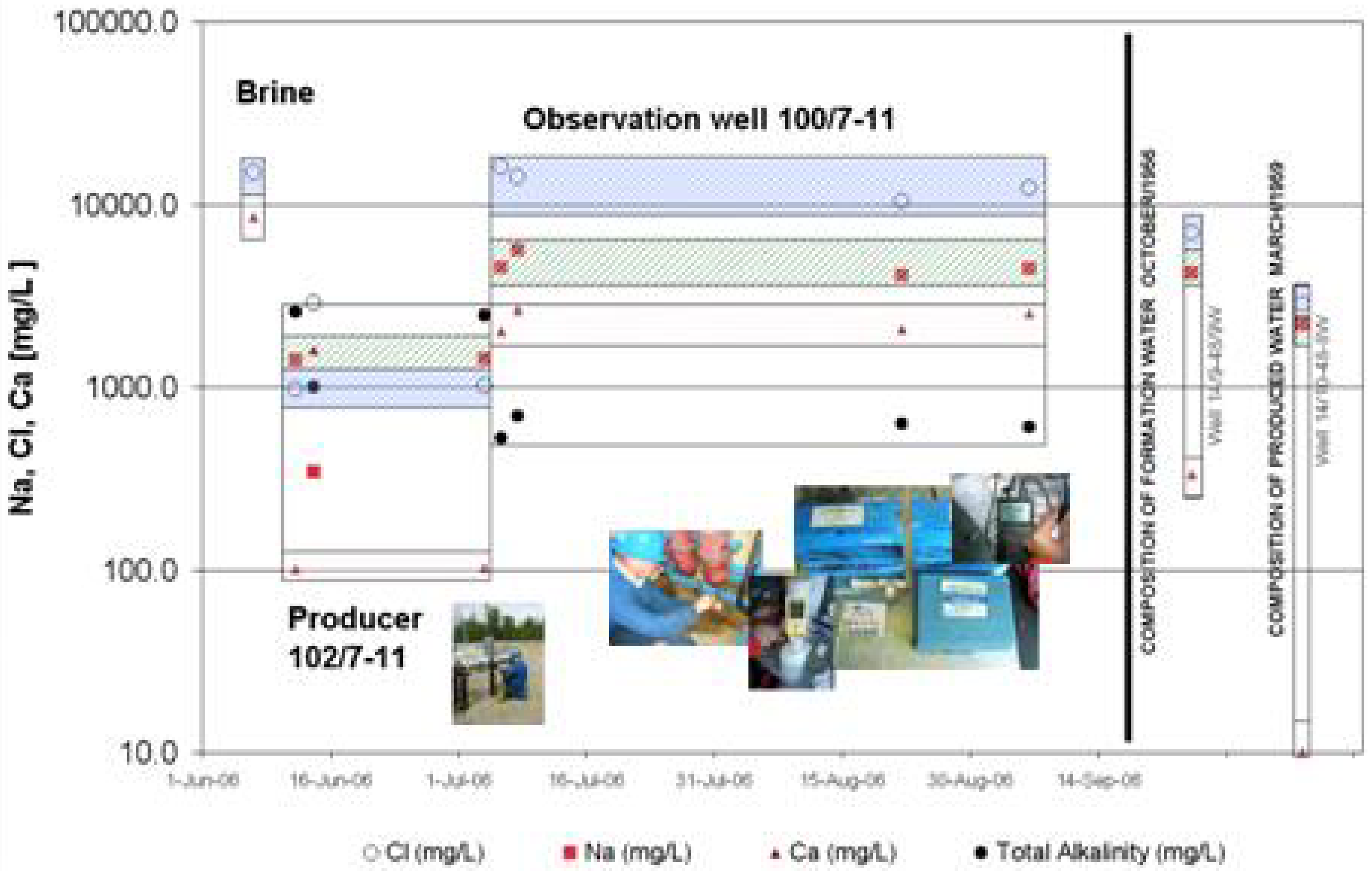


Fluid Sample System

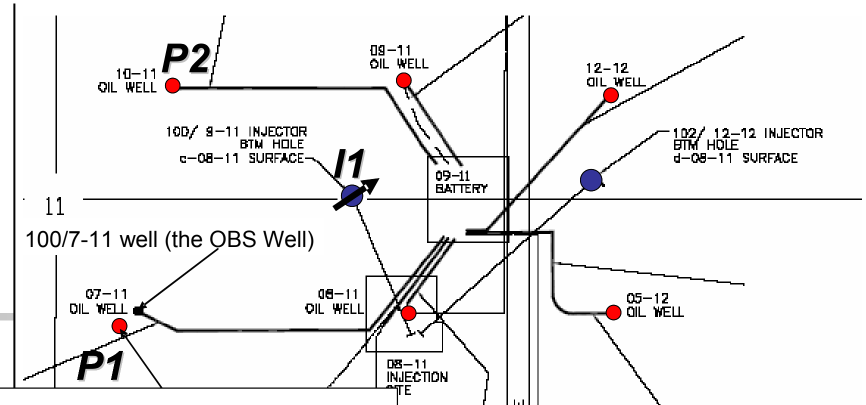


Fluid S ocol

Evolution of Aqueous Composition

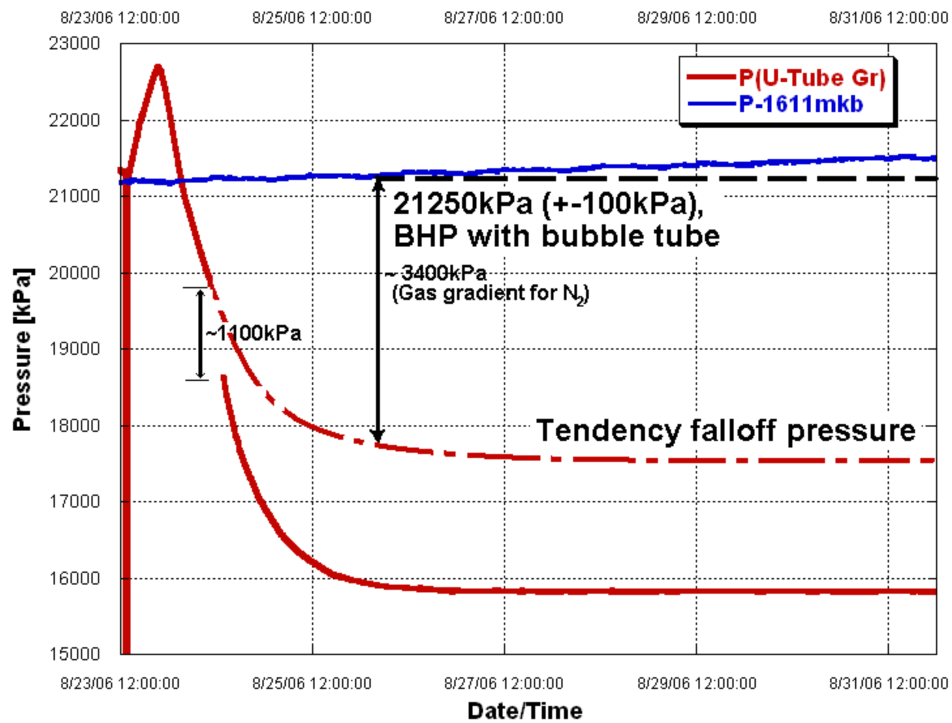


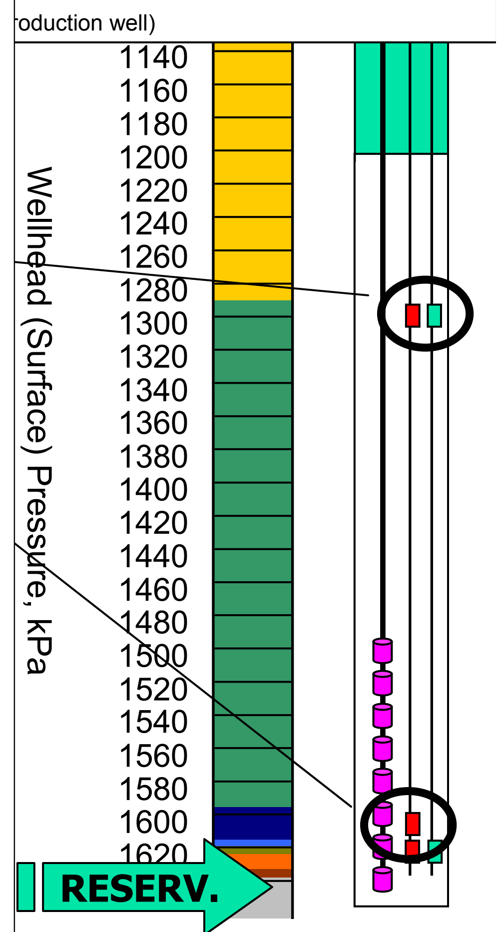
Obs. Well Pressures



BHP Monitoring from Bubble Tube Test

BHP can be obtained from a capillary line or bubble tube





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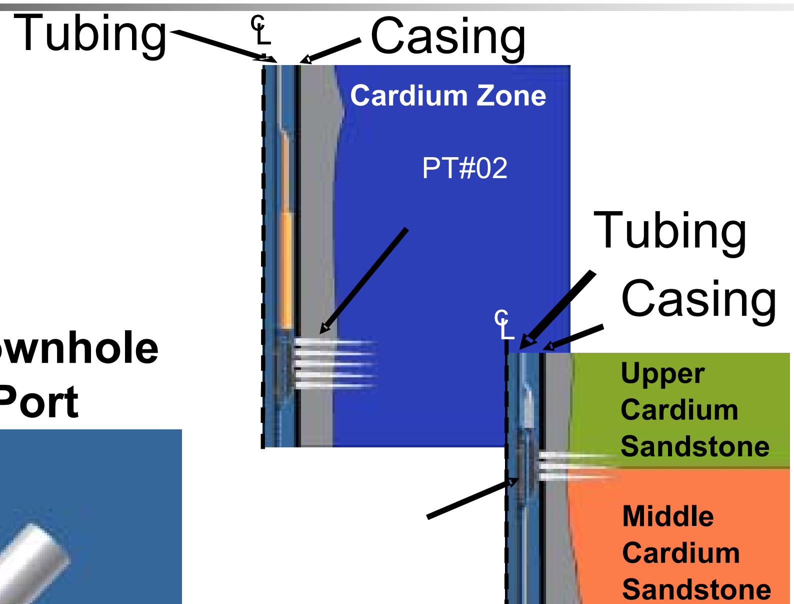
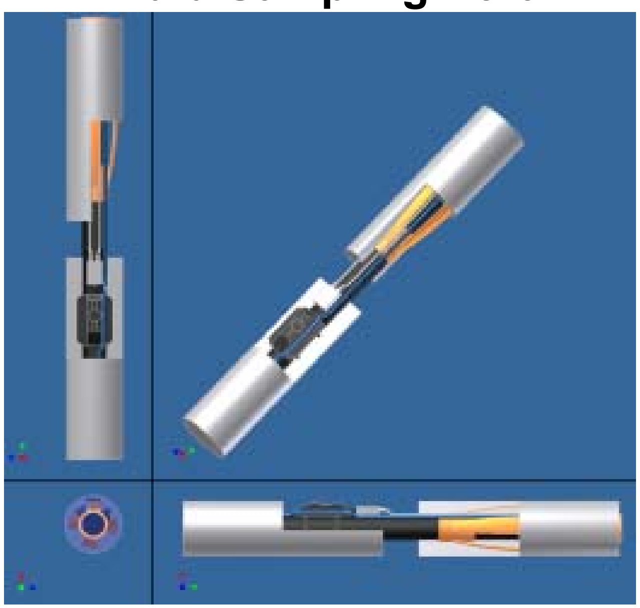
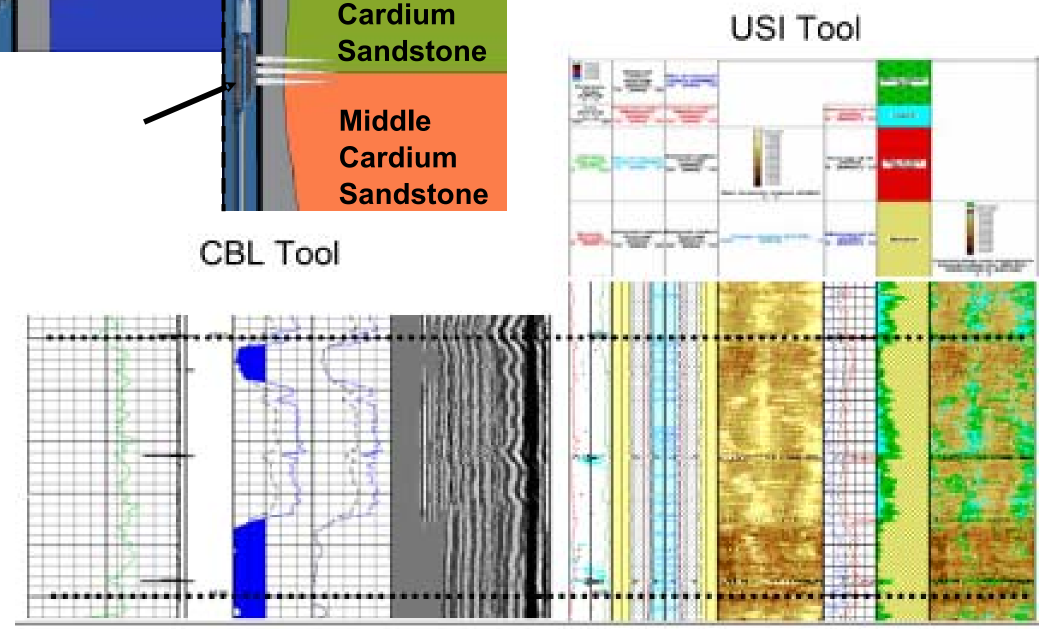
Near Well Integrity Assessments



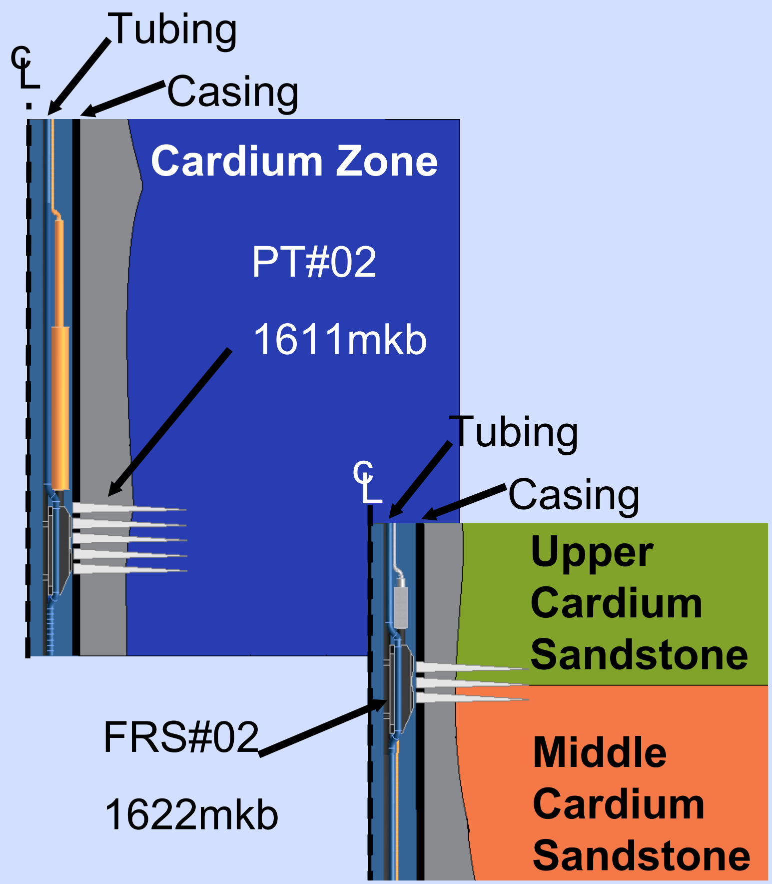
3D Model of FRS Downhole
Fluid Sampling Port



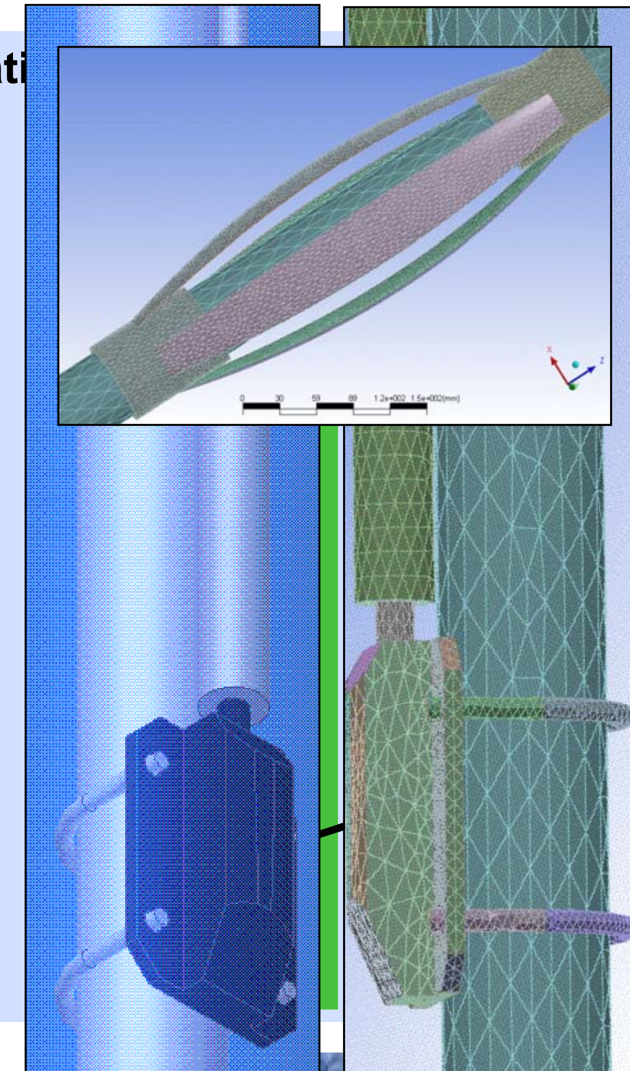


Detailed Near-Well Modeling

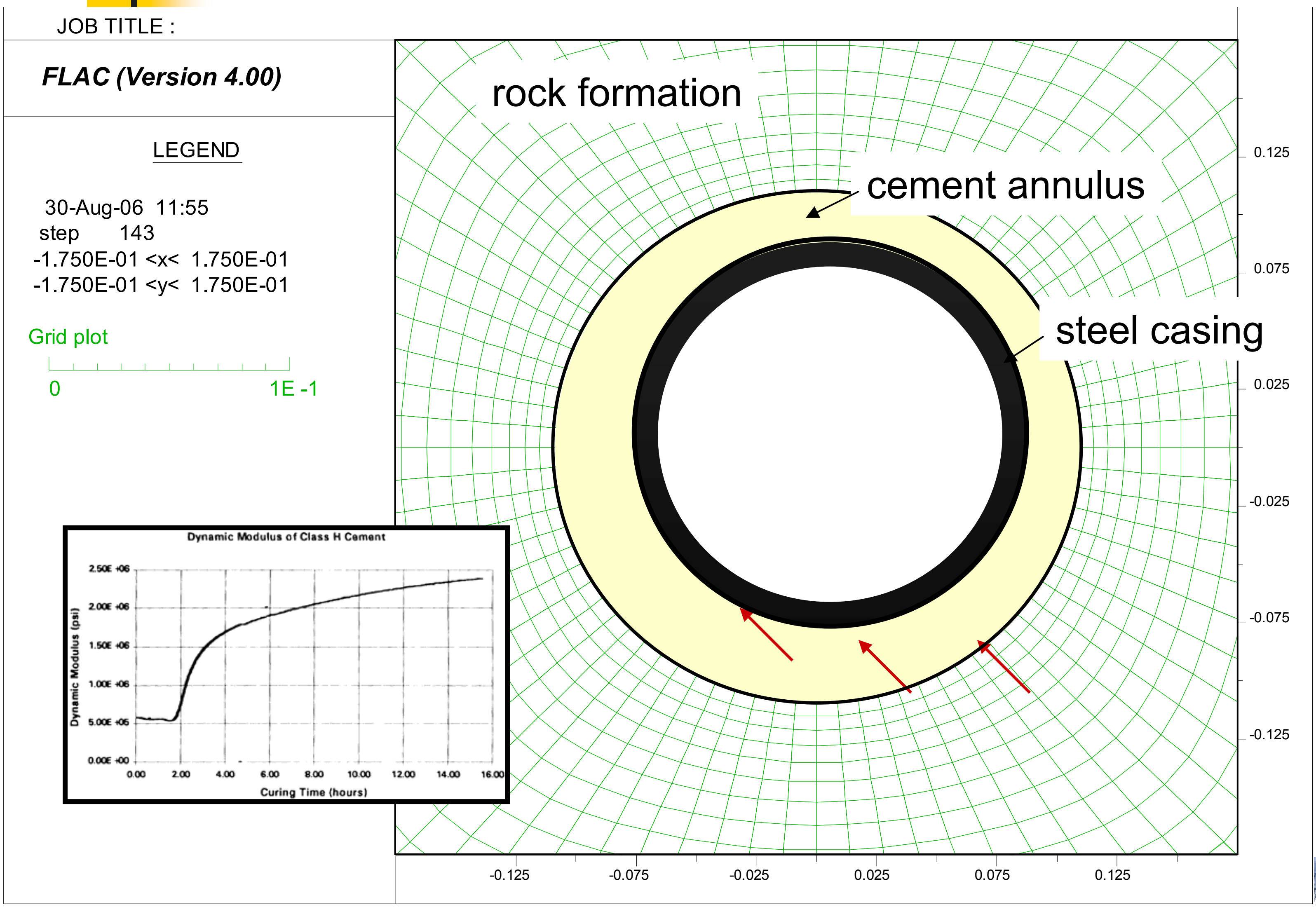
Perforations at 1600mkb's, 13 sh/m



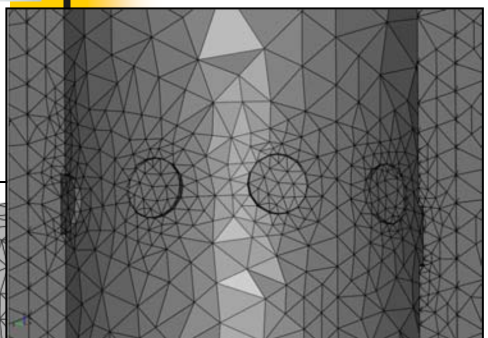
Perforati

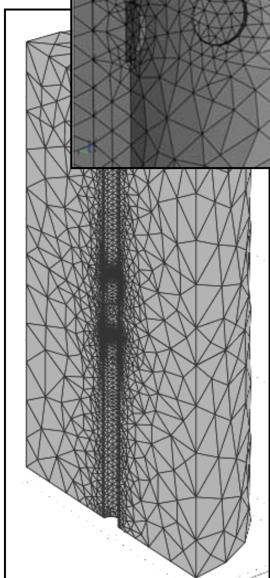


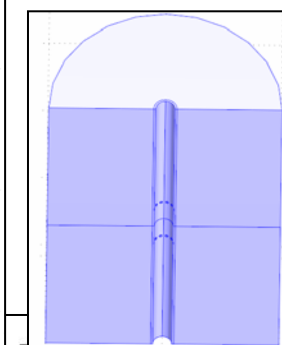
Detailed Near-Well Modeling

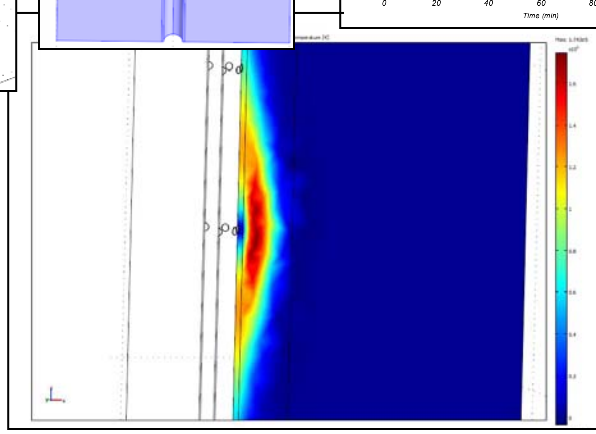


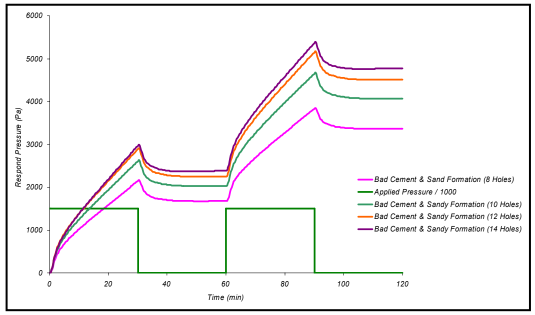
Cement Behavior and Well Abandonment Strategies

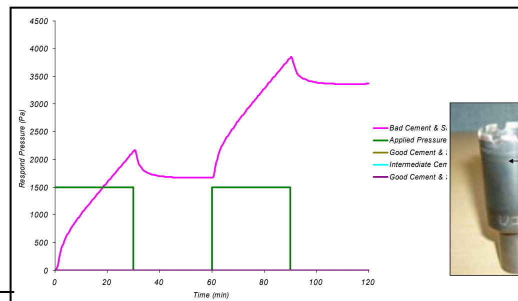


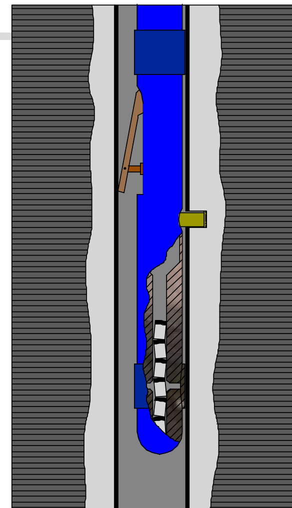










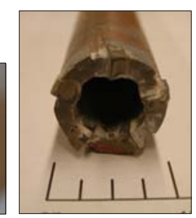


Grinding Tools:

Cubic boron nitride (CBN)

Splintered carbide

Annular Carbide Cutters:



Annular HSS Cutters:

Summary

- Integrated instrumentation systems provide multiple datasets to interpret well response
- Provide valuable lessons on permanent downhole instrumentation deployment
- Critical data for verification of wellbore integrity models

3rd Wellbore Integrity Network Meeting

Role of Permanent Downhole Integrated Instrumentation Systems in Assessing Wellbore Performance - Penn West CO2-EOR Monitoring Project

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Degradation of Wellbore Cements: Results of Long-Term Experiments and Effect of Additives

Barbara Kutchko[1,2]
Brian Strazisar[1]
David Dzombak[2]
Greg Lowry[2]
Niels Thaulow[3]

[1]U. S. Department of Energy NETL
[2]Carnegie Mellon University
[3]RJ Lee Group

Wellbore Integrity Network Meeting
March 12, 2007

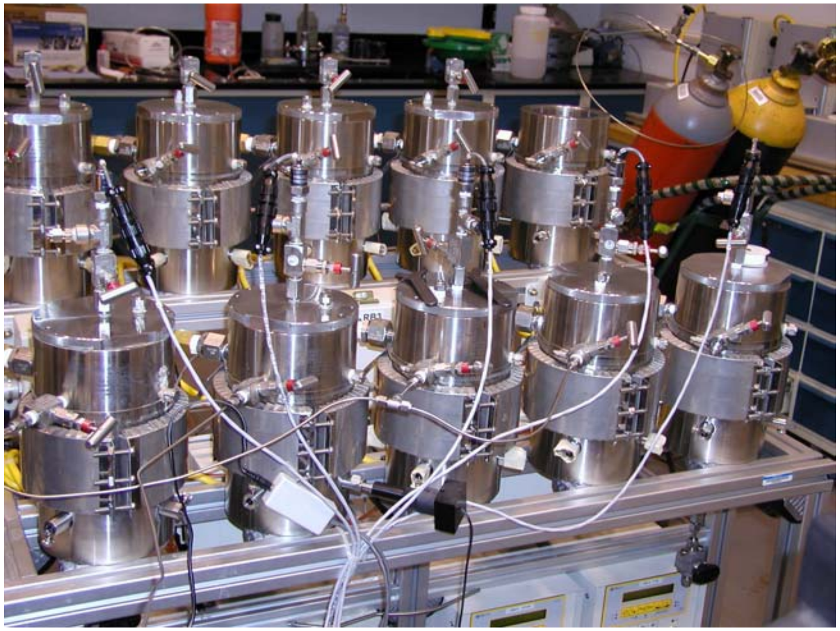
NETL

Degradation of Wellbore Cements: Results of Long-Term Experiments and Effect of Additives

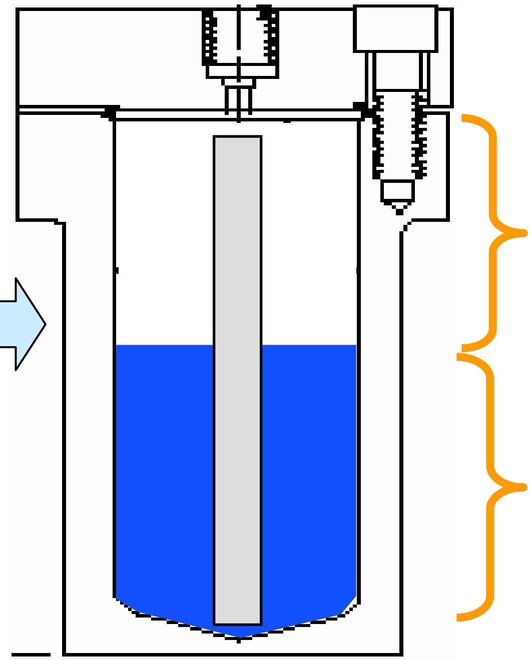
- **Laboratory Degradation Study**
  - Focus is on cement of ***existing*** wells
- **Results of 1 year Experiment (Neat Cement)**
  - Rate and Mechanism of Degradation
  - Comparison to Field Sample
- **Effect of Additives**
  - Changes in Rate and Mechanism
- **Conclusions**

Sample Preparation

- **Cement Samples prepared according to API Recommended Practice 10B**
  - Class H neat
- **Cylindrical samples ½" in diameter (~12.5mm)**
- **Hydrated for 28 days in 1%NaCl solution**
  - T = 50°C, P = 4400 psi



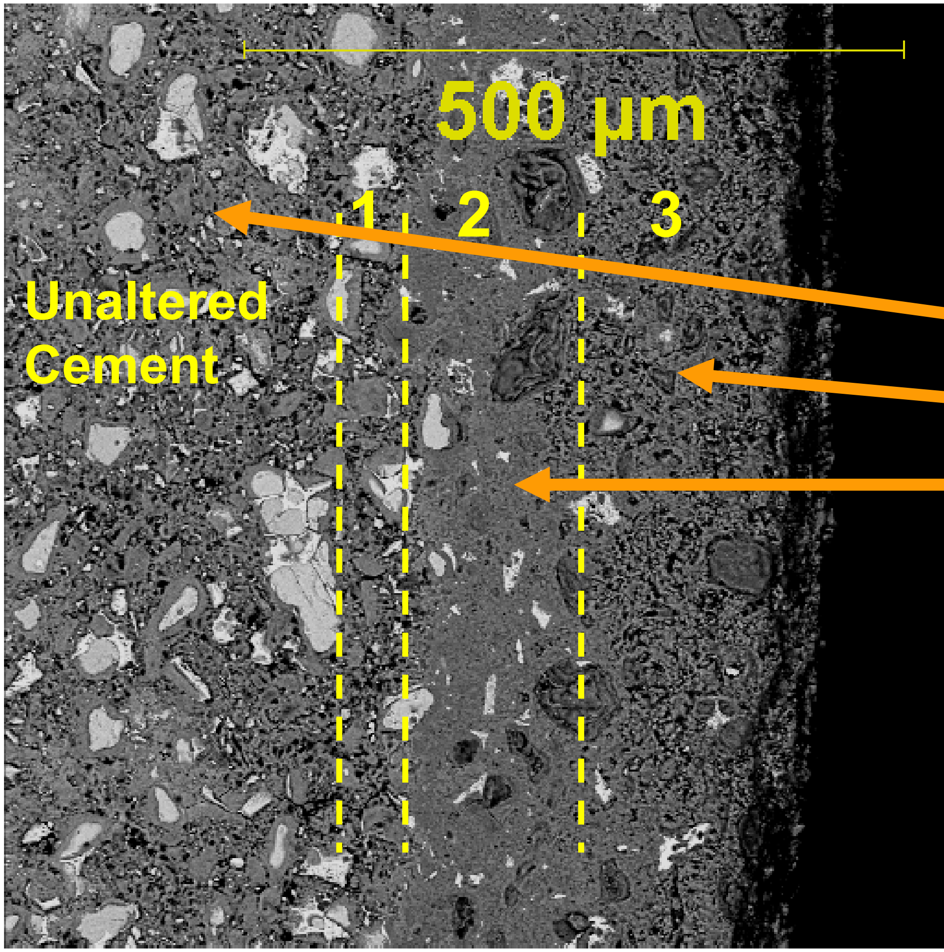
CO_2 - Sequestration Exposure Experiments



Headspace: water saturated CO_2

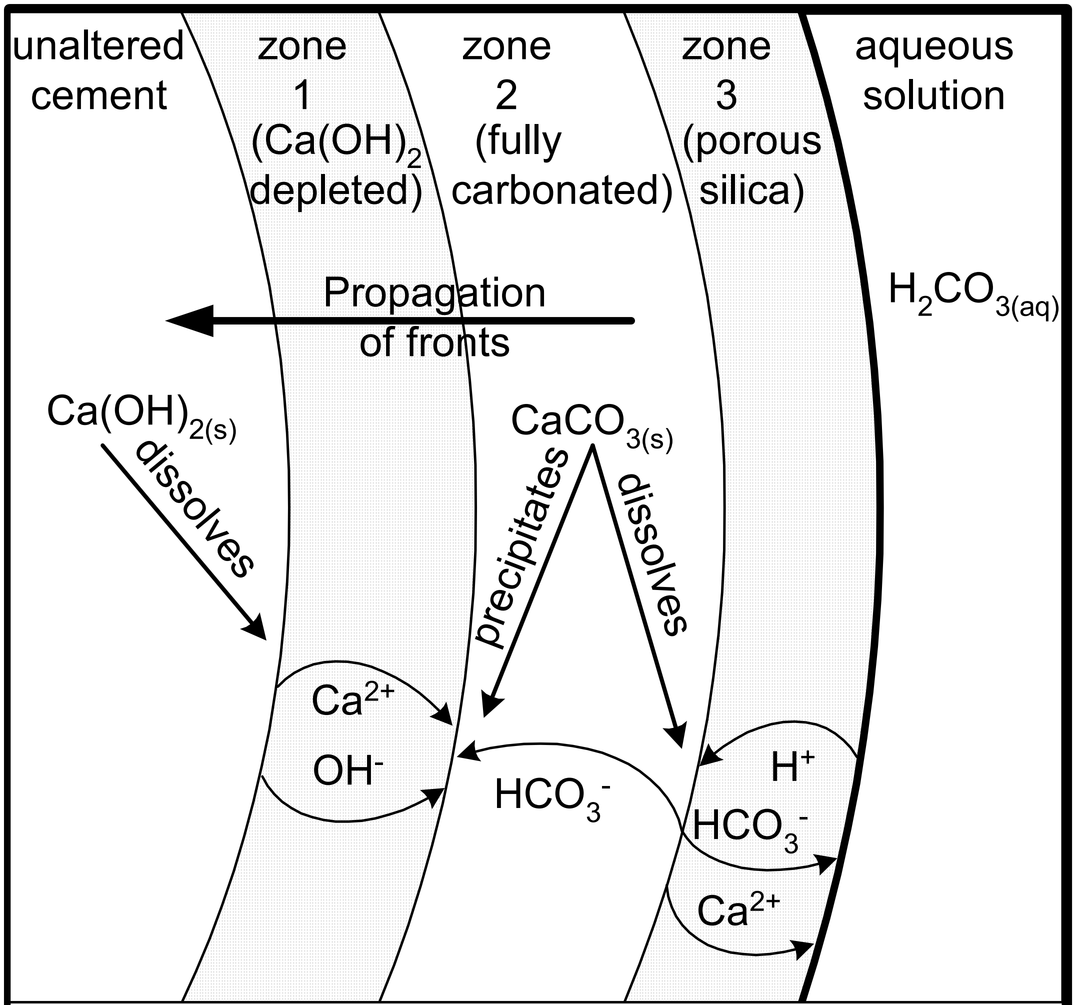
Aqueous phase saturated with CO_2

Progression of Cement Degradation



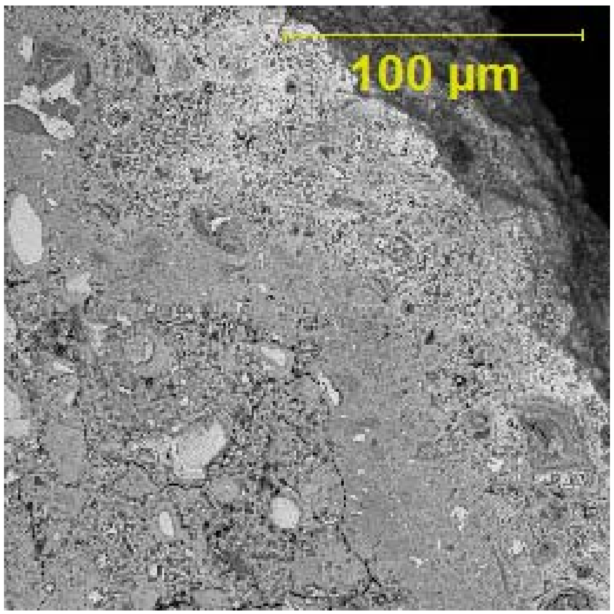
- **Distinct Zones of Reaction**
- **Microhardness (100g):**
  - Unreacted cement **64HV**
  - Exterior **25HV**
  - Rim **127HV**

Degradation Mechanism

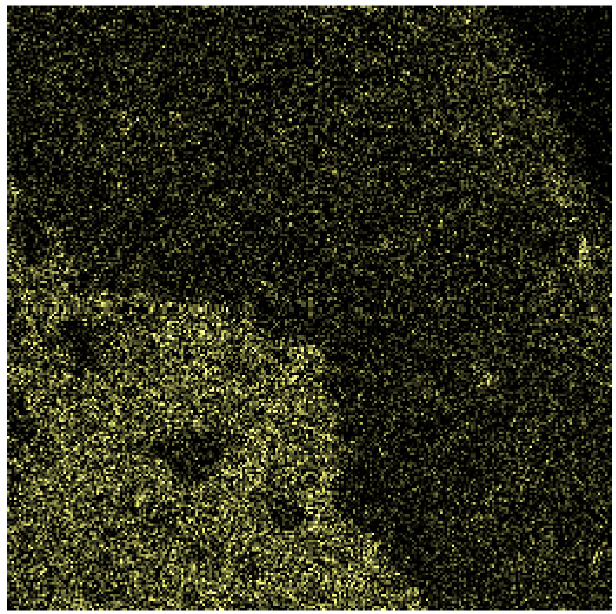


- **Zone 1**
  - Dissolution of $Ca(OH)_2$
- **Zone 2**
  - Precipitation of $CaCO_3$
- **Zone 3**
  - Dissolution of $CaCO_3$
  - Decalcification of C-S-H

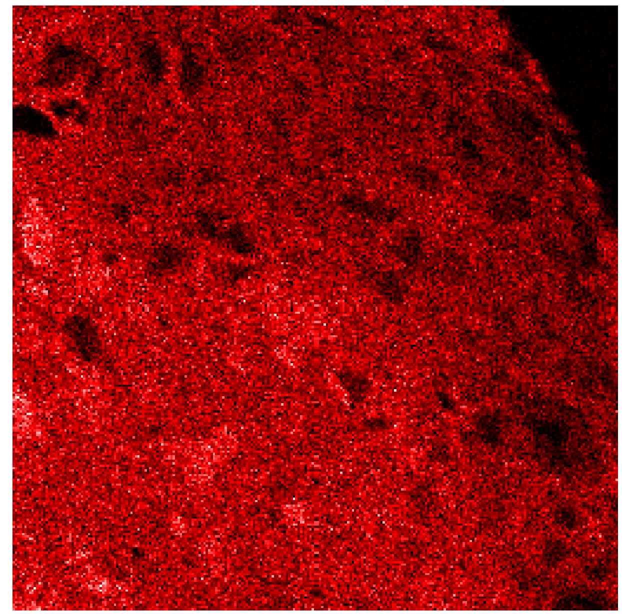
Class H cement -- 9 day – aqueous phase X-ray maps



BSE Image

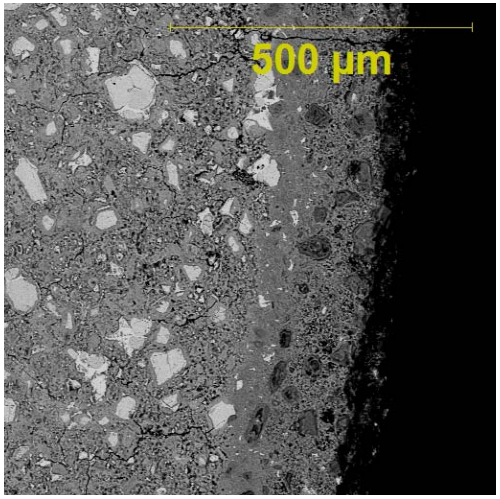


Cl

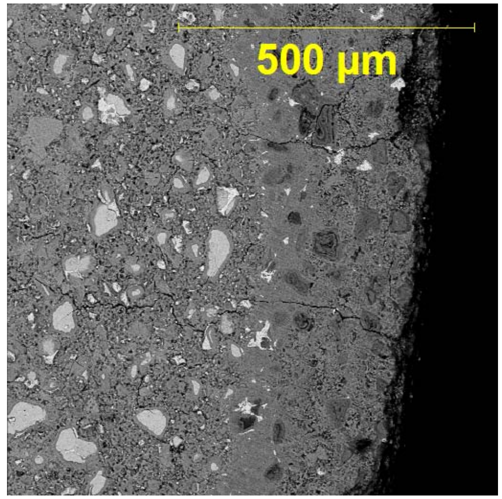


Ca

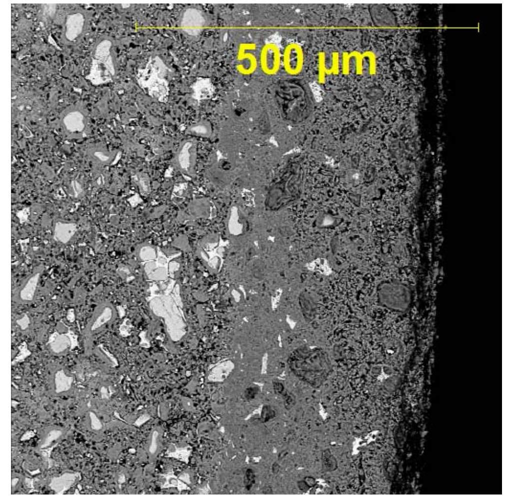
Progression of Degradation– Aqueous Phase



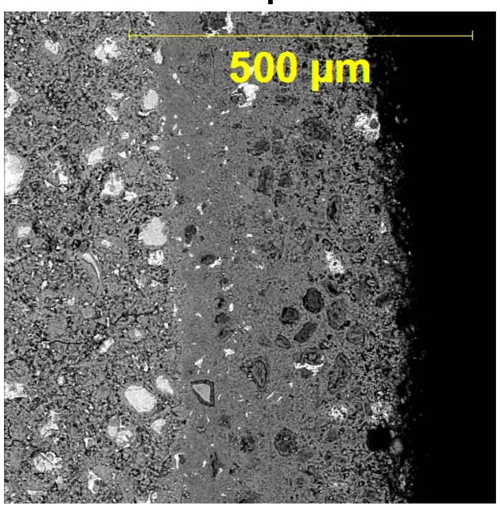
9 days
351 µm



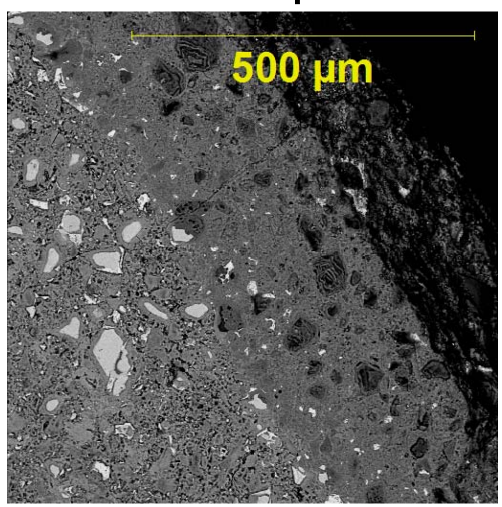
23 days
451 µm



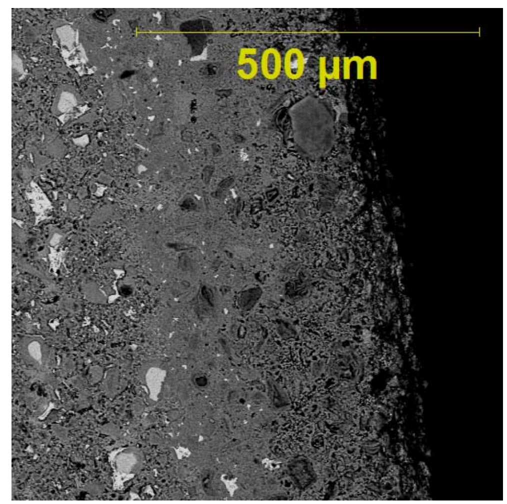
61 days
550 µm



90 days
603 µm

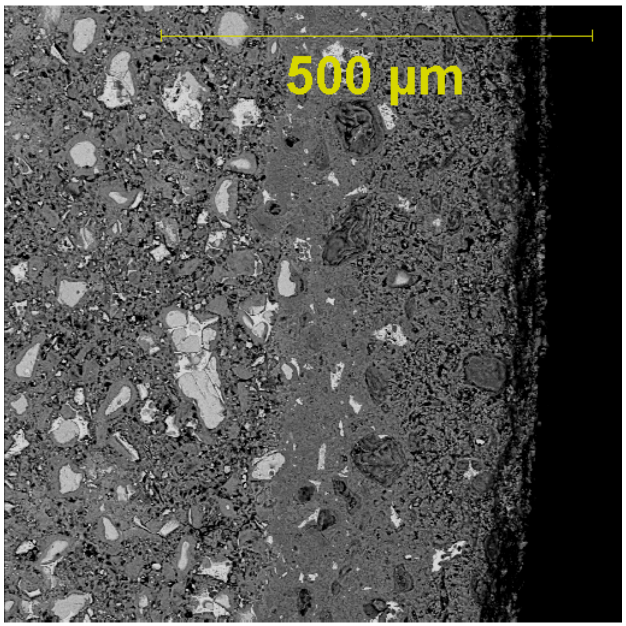


156 days
639 µm

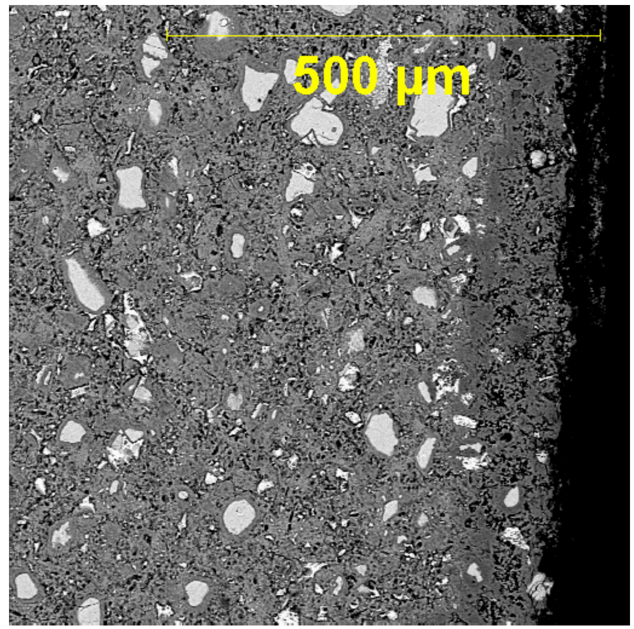


365 days
605 µm

Aqueous Phase vs Headspace

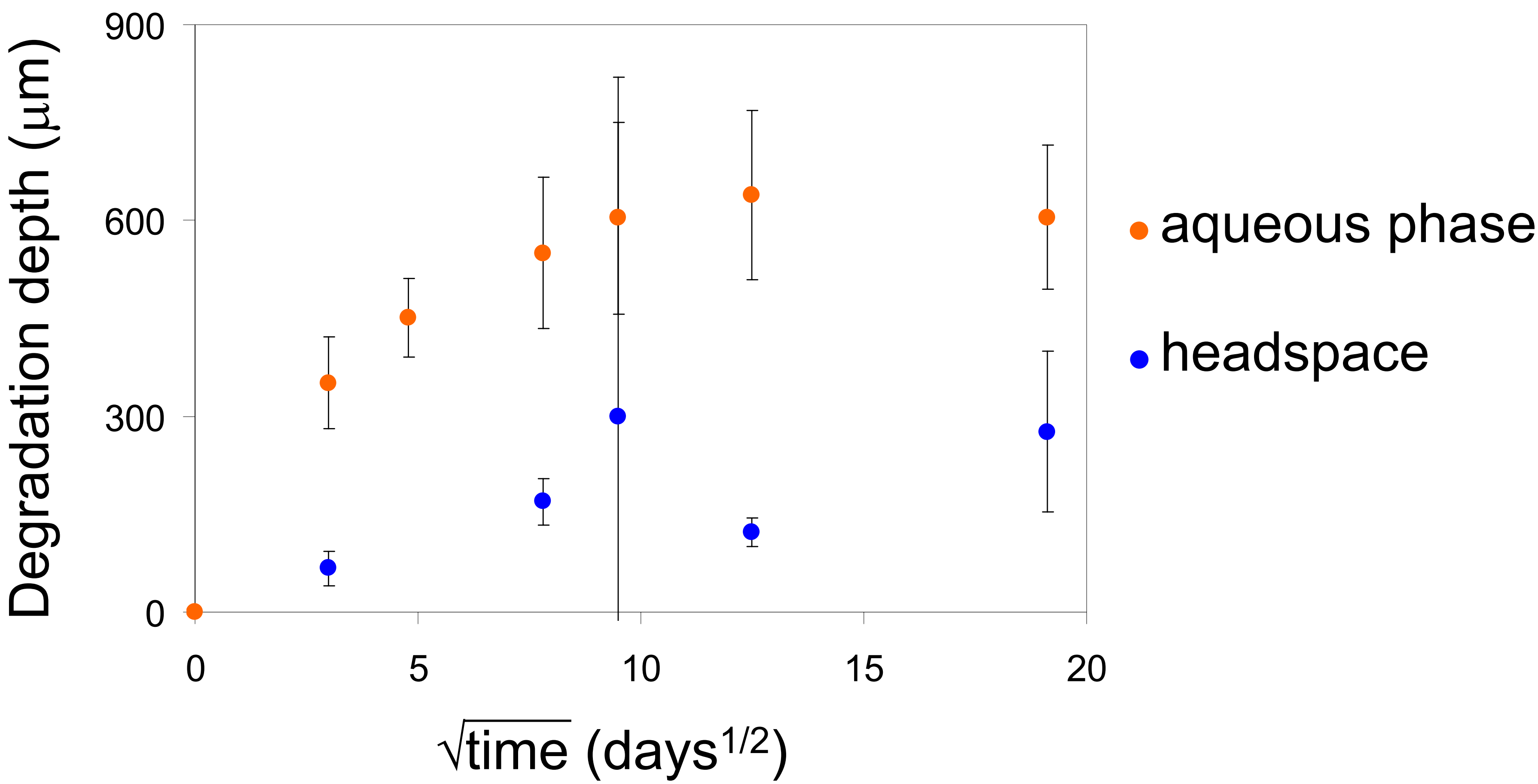


Aqueous Phase: 61 days
HTHP CO_2 exposure

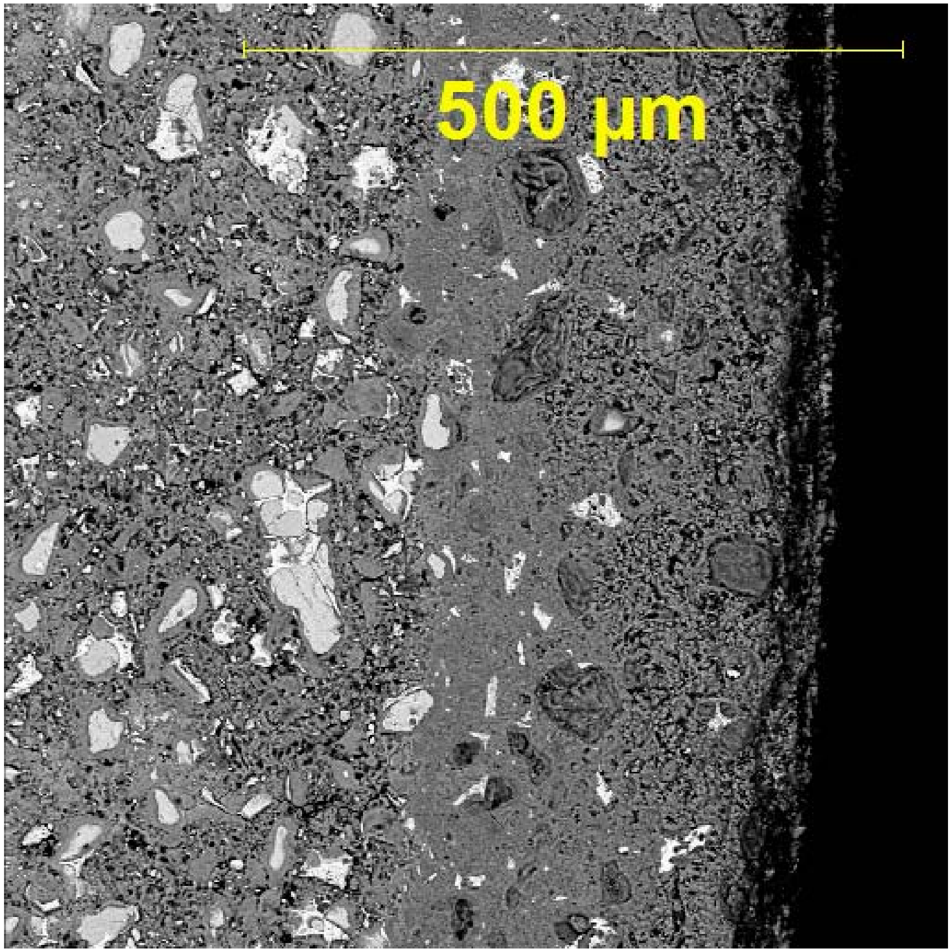


Headspace: 61 days
HTHP CO_2 exposure

One year degradation of neat class H cement



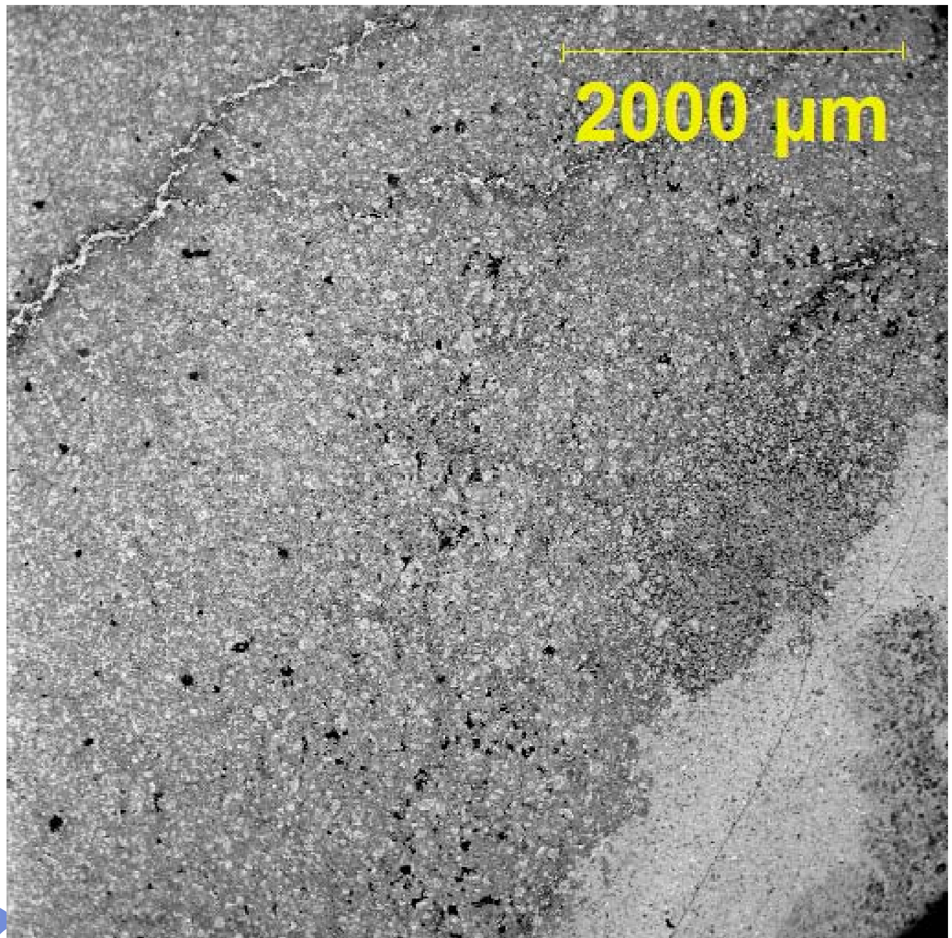
Degradation Rate



- **Ficks 2nd law of diffusion is typically used to predict carbonation depth:**
  - $X = D = \alpha t^{½}$
  - Where α is related to rate of carbonation and is dependant on cement properties.

- **The formation of the $CaCO_3$ rich layer (zone 2) slowed the rate of degradation.**
  - Permeability decrease leads to slower diffusion as carbonated layer forms.

LANL- SACROC Sample



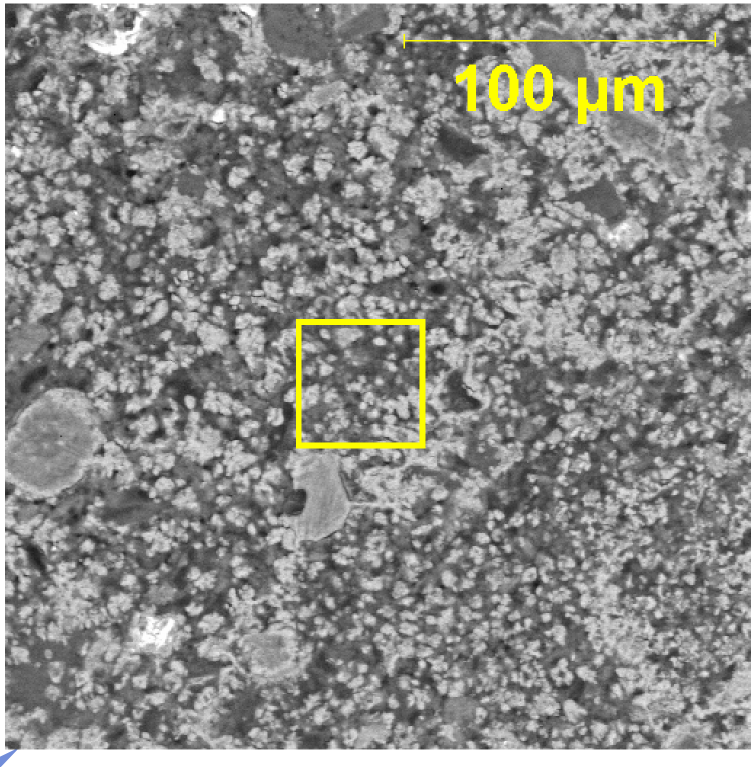
- Neat cement - 30 years of CO_2 exposure
- Clear reaction zones as observed in our experiments
- Degradation depth ranged from 2 - 10mm

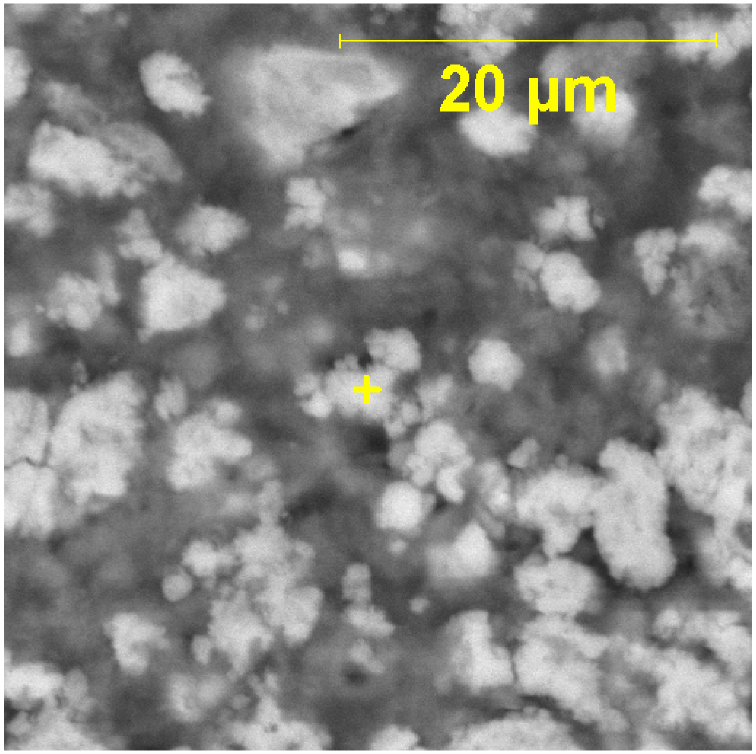
Cement Additives/Cement Blends

- **6% Bentonite**
- **Pozzalon Systems**
  - Type F fly ash
  - 2% bentonite added to avoid development of free water
  - **35:65 pozzalon/cement mix**
    - Slurry density 14.51 lb/gal
  - **65:35 pozzalon/cement mix**
    - Slurry density 13.70 lb/gal

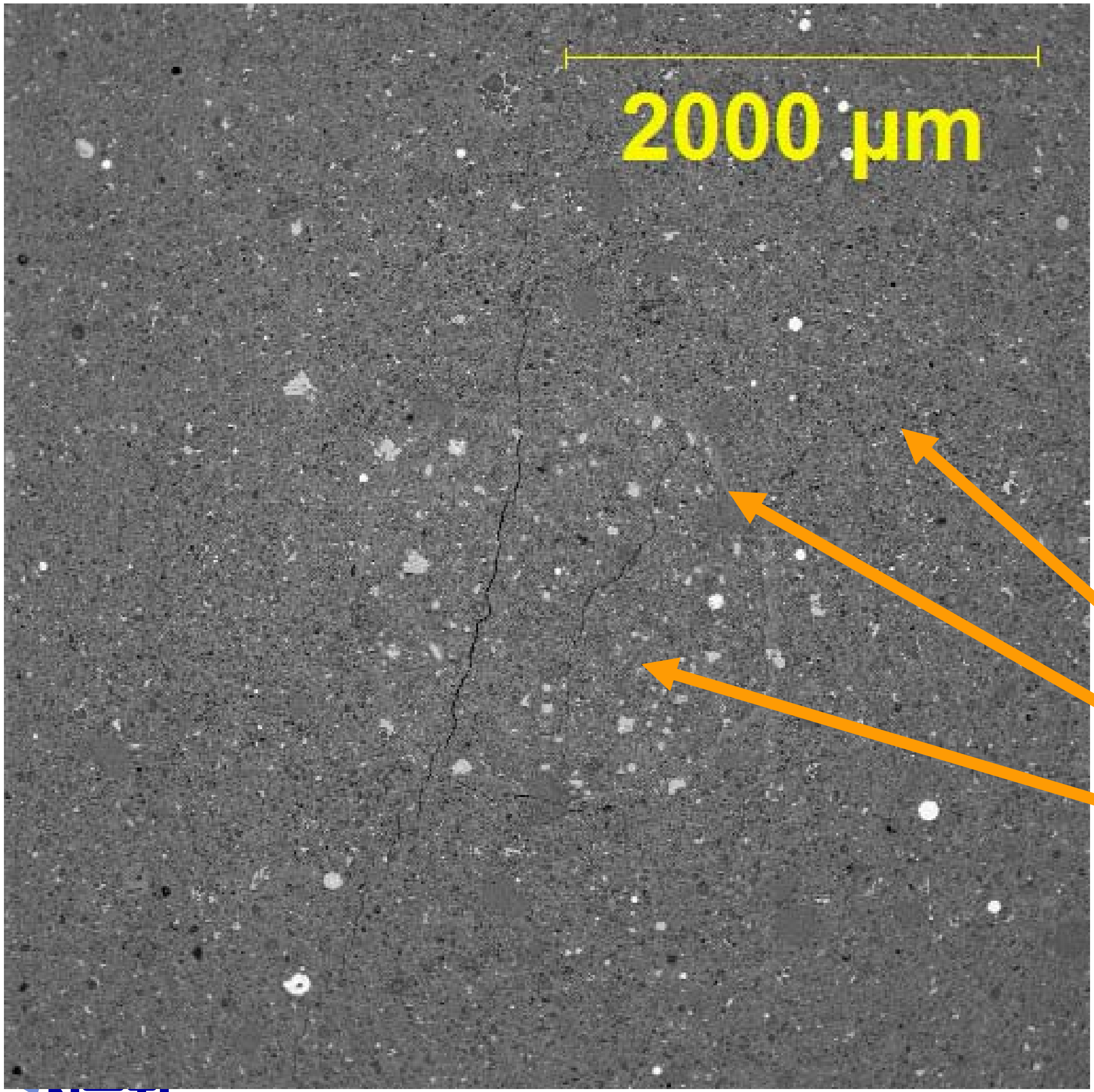
Class H with 6% Bentonite

- **Complete Degradation within 9 days**
- **Bicarbonation leaves behind "Popcorn" crystals of calcite in an isotropic matrix of silica gel.**



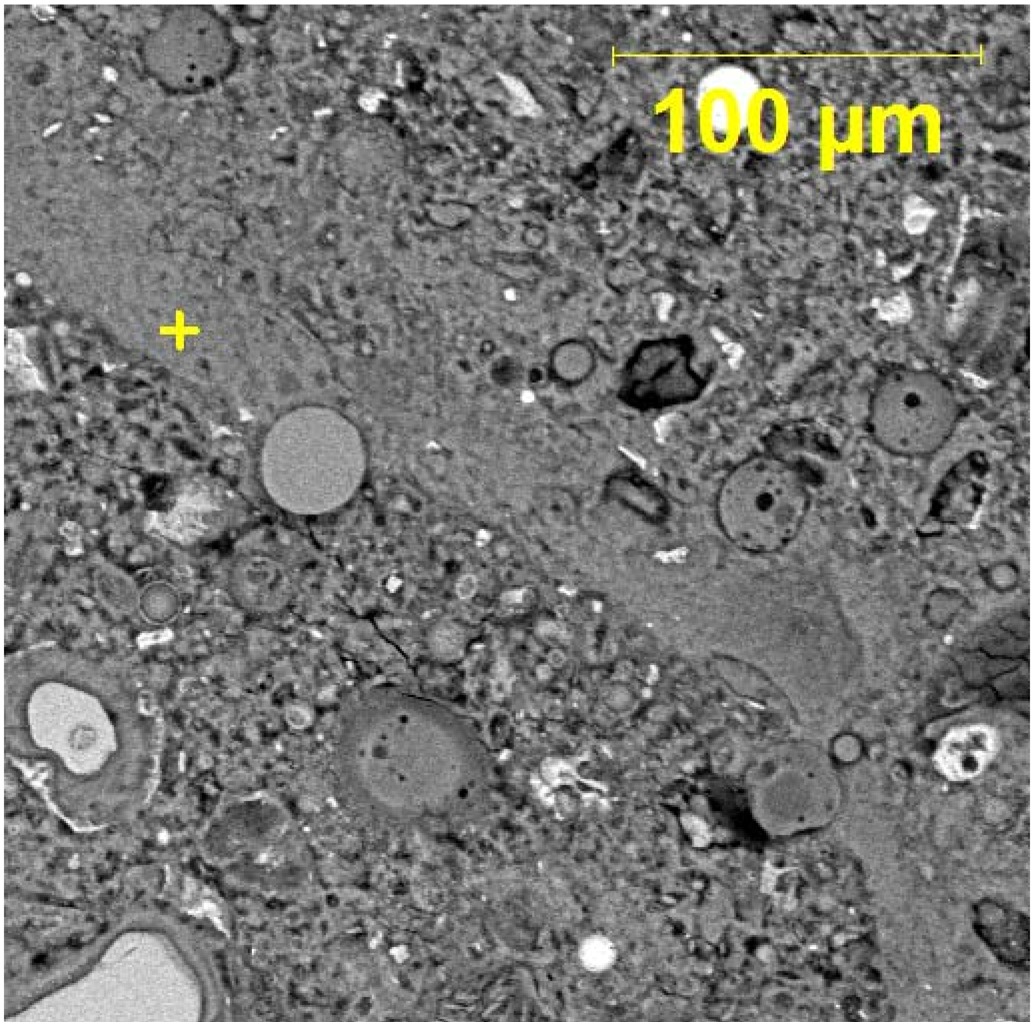


35:65 Pozmix/Cement - 9 day - bottom



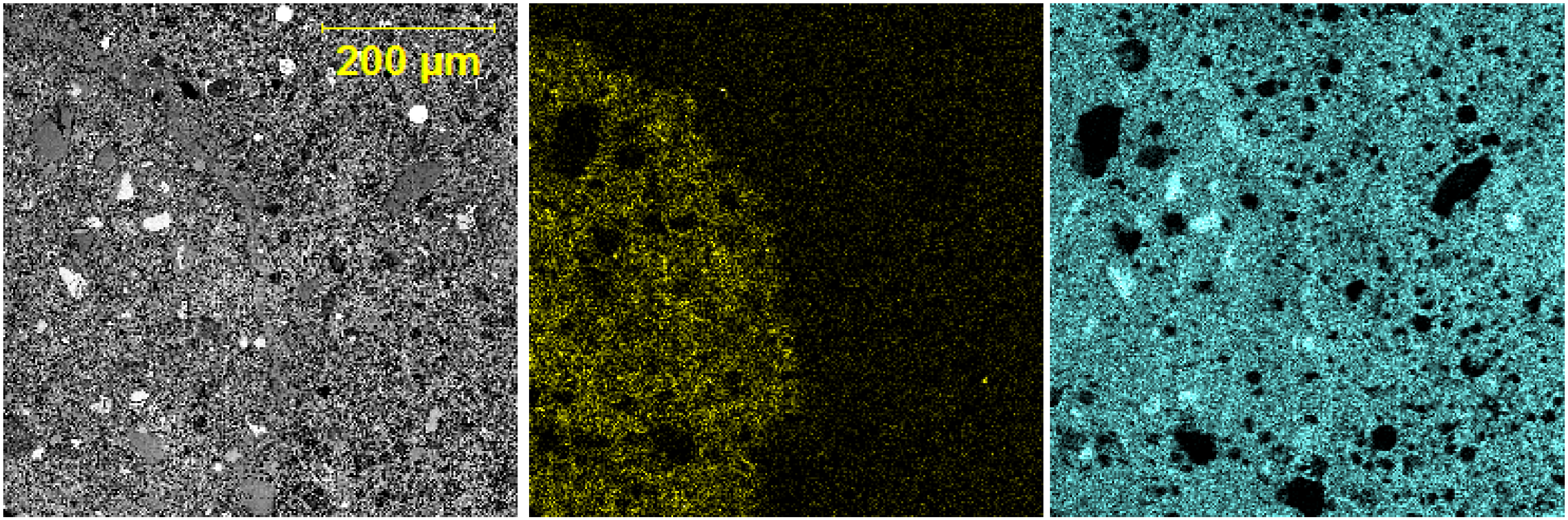
- **Carbonated Rim at ~5.5mm depth**
- **Microhardness(100g):**
  - Unreacted cement **38HV**
  - Exterior **24HV**
  - Rim **68HV**
  - Interior **34HV**

35:65 Pozmix/Cement - 9 day - bottom



- **Carbonated rim is more narrow than in neat cement**
- **Inside Rim**
  - AFt
  - Chloride
  - Cement grains
- **Outside Rim**
  - No Aft
  - No Chloride
  - Calcium depleted cement grains

35:65 Pozmix/Cement - 9 day – aqueous phase X-ray maps

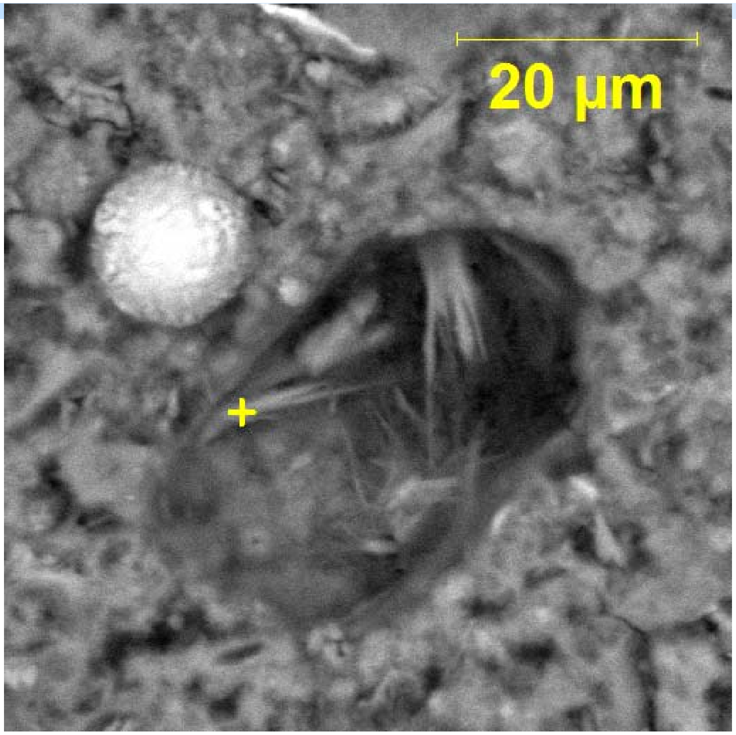


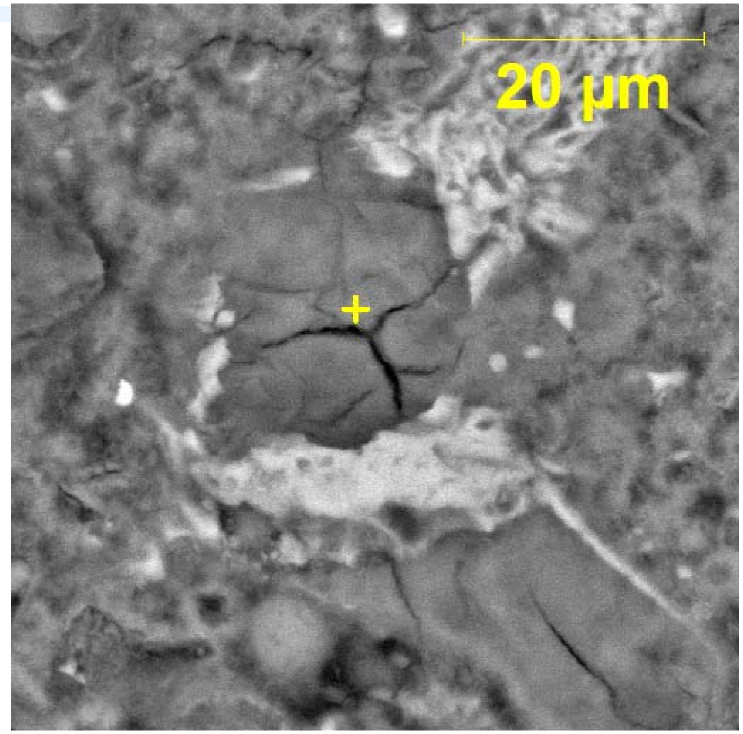
BSE Image Cl Ca

Conclusions

- Degradation of neat cement is a slow and decelerating process
- Rate is diffusion limited with effective permeability decreasing as carbonates precipitate in pores
- Result is qualitatively consistent with field experience
- Additives change degradation process significantly, and increase degradation rate in all cases we've tested

NETL

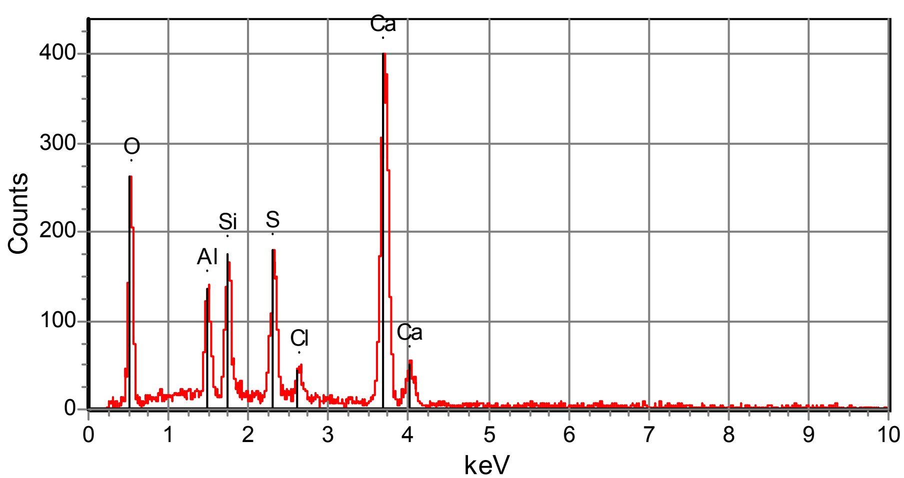


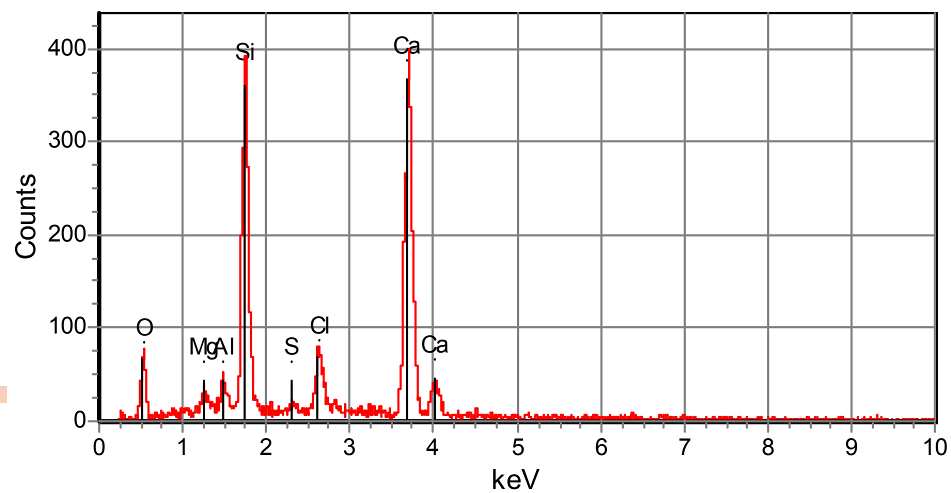


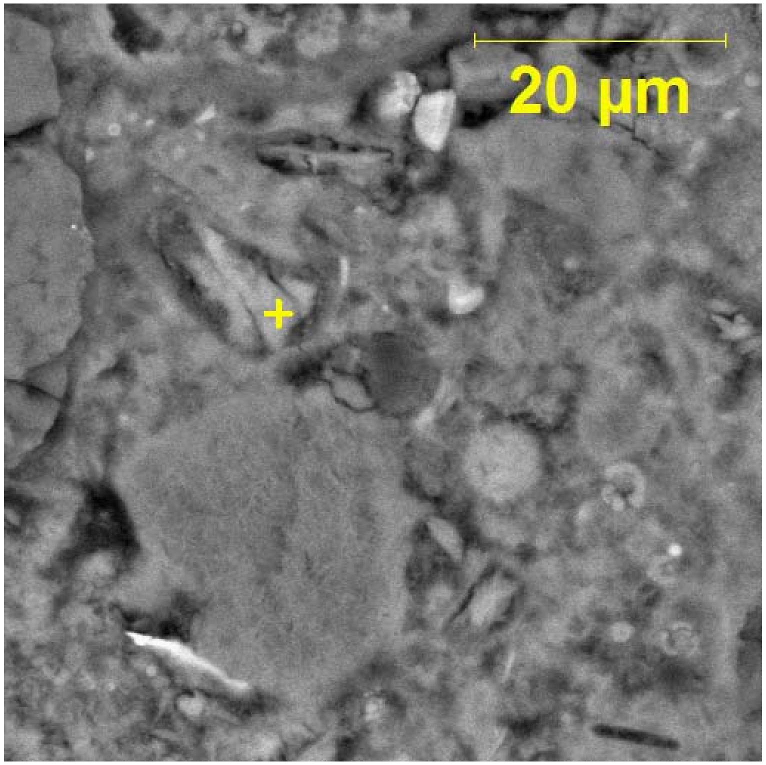
Si, Cl-rich AFt

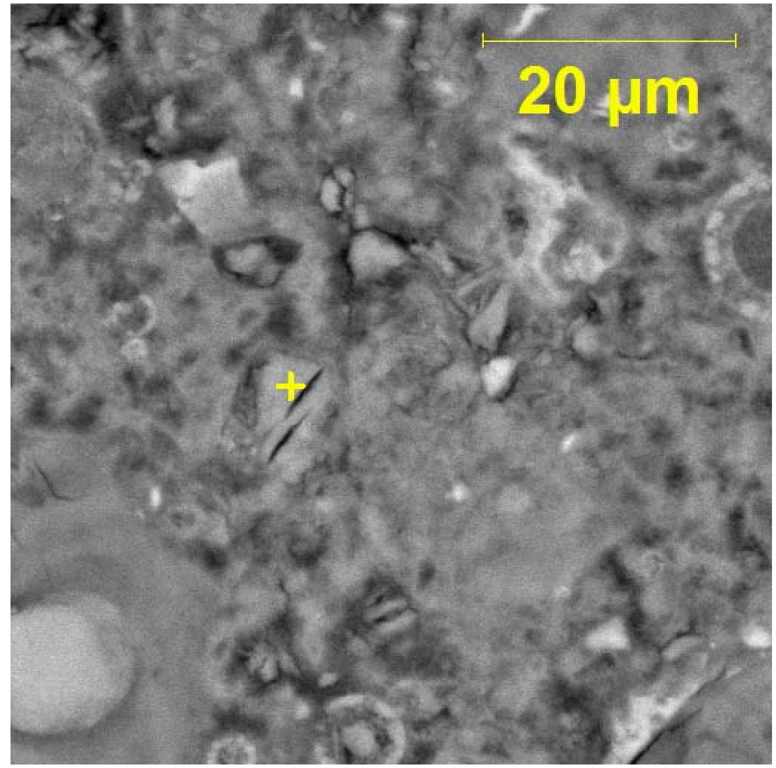
interior

Unknown, possibly Cl-containing CSH



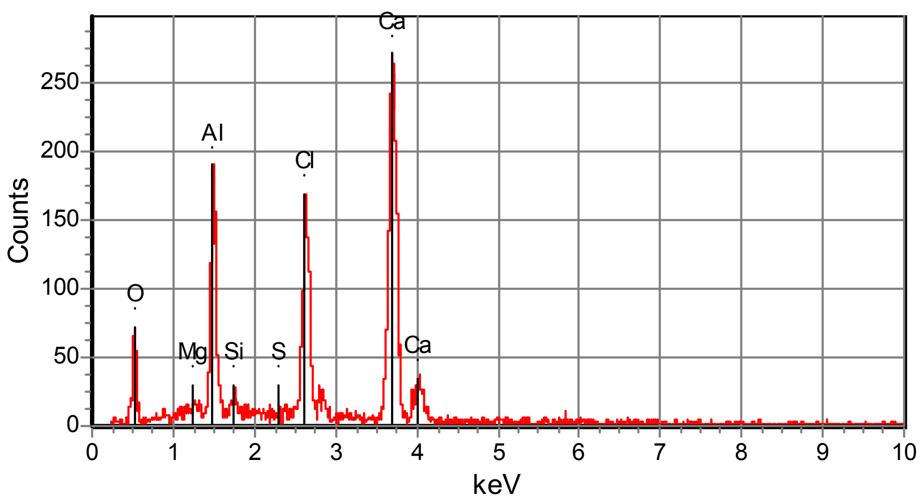


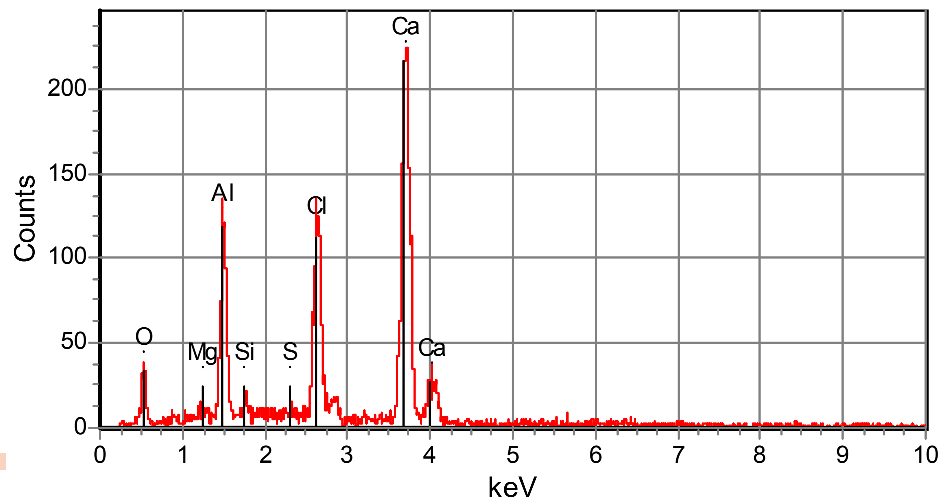




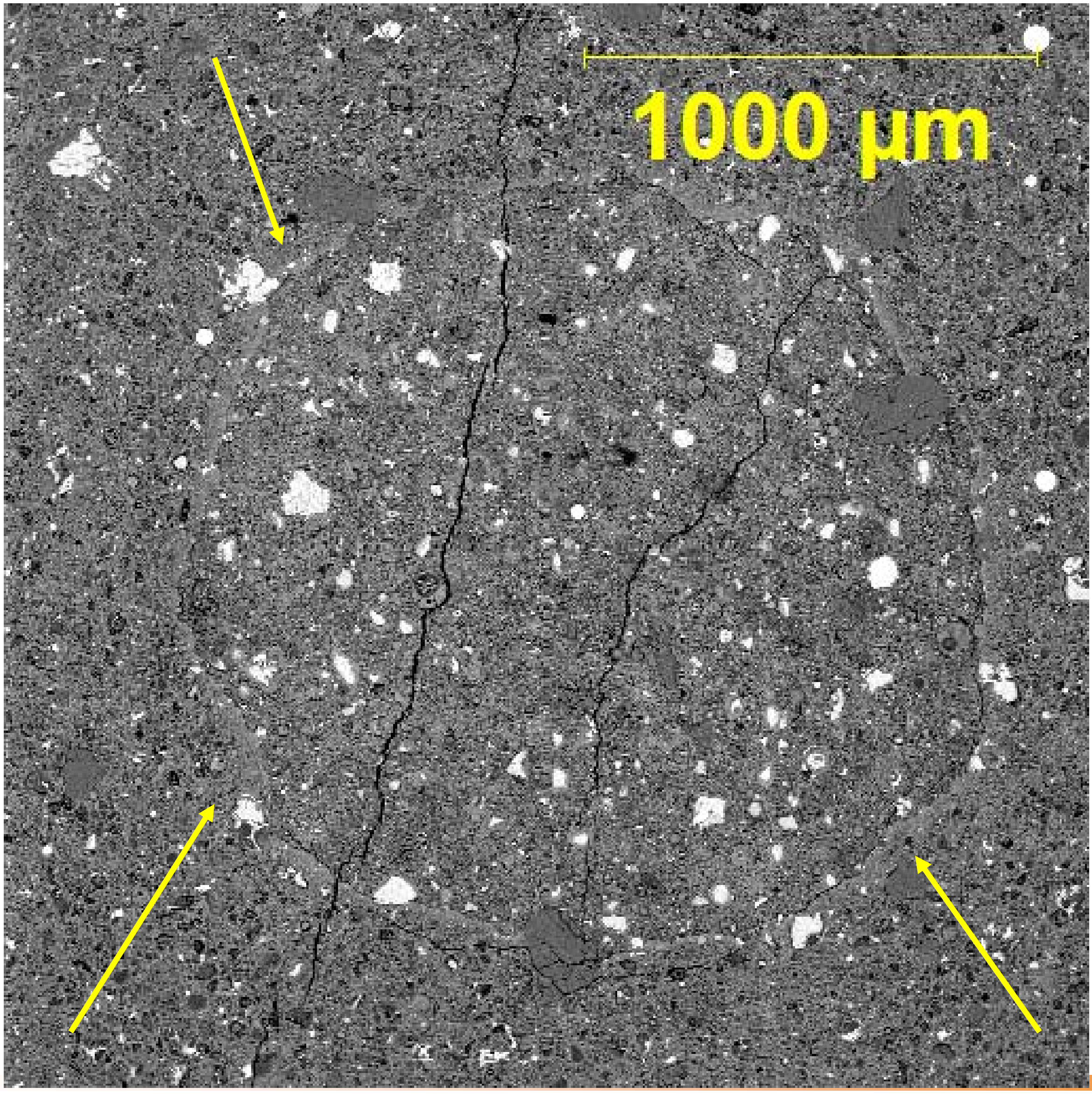
More Cl-rich AFt,

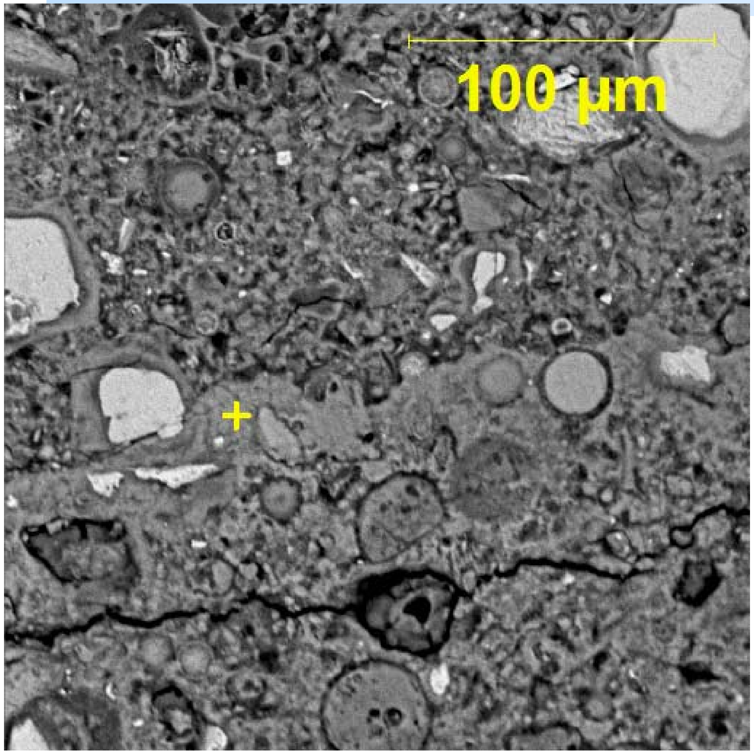
interior



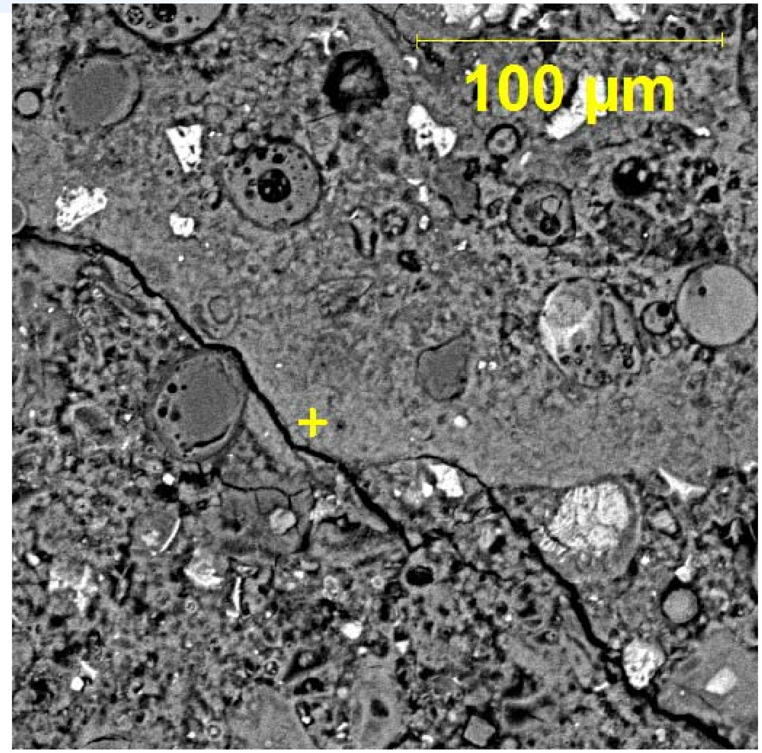


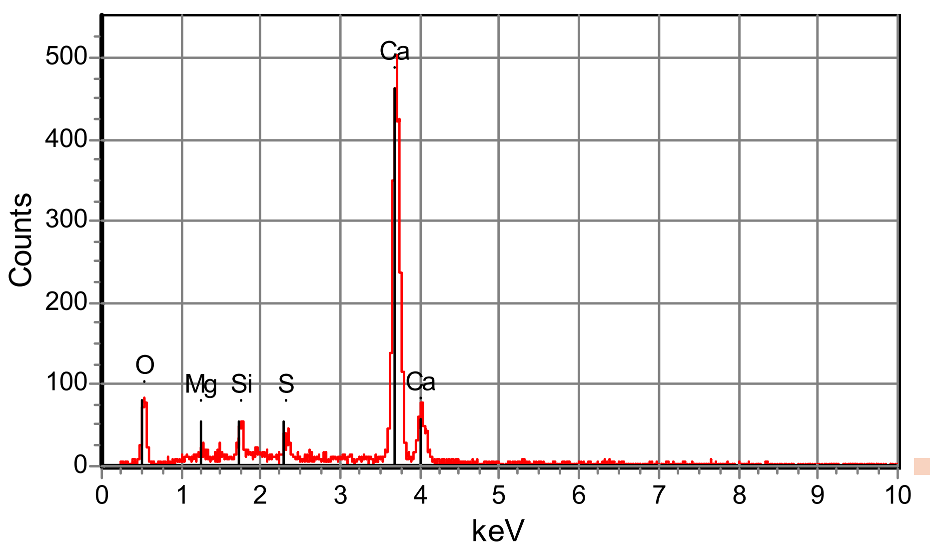
35:65 Bottom

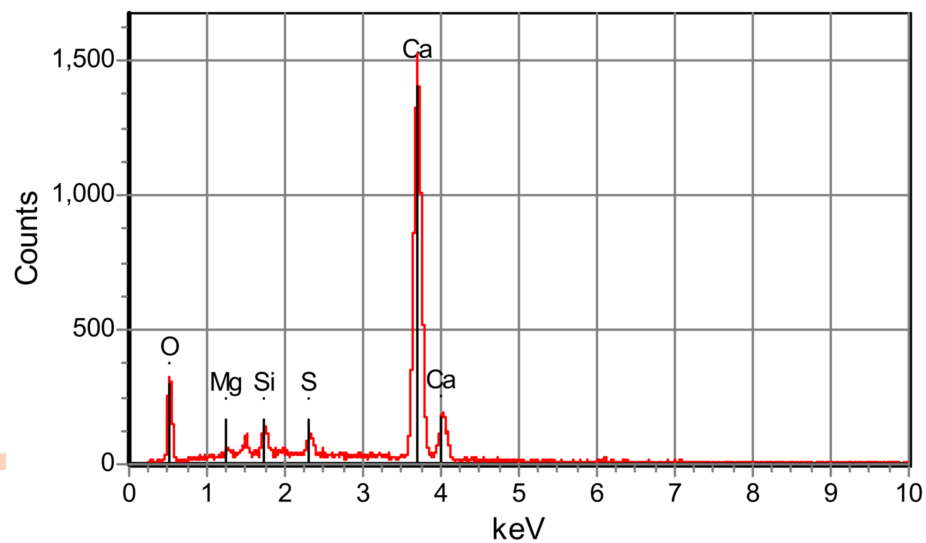


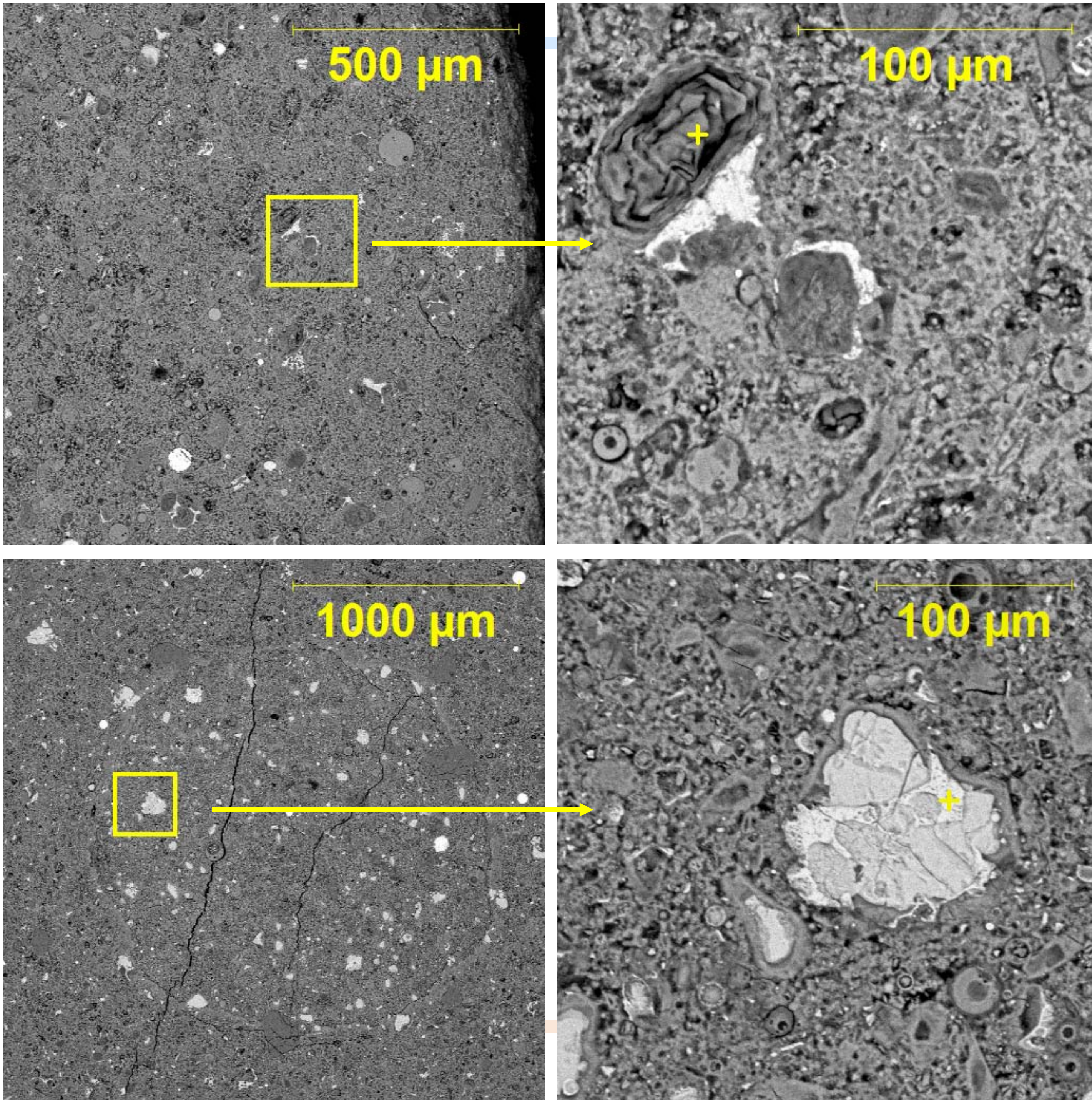


BSE images and EDS of ring structure



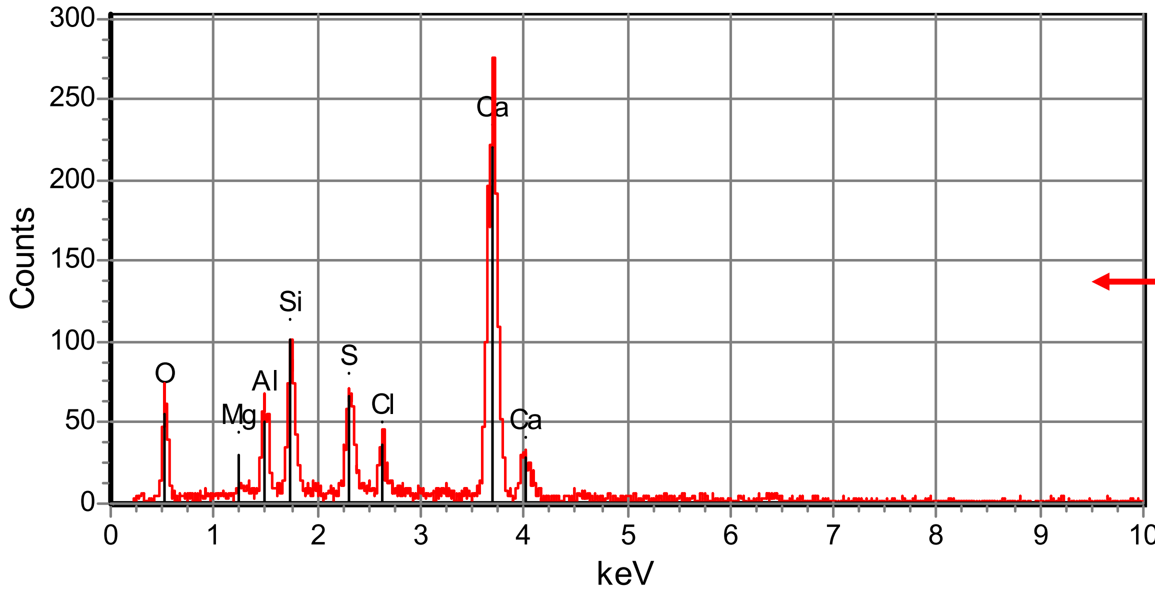


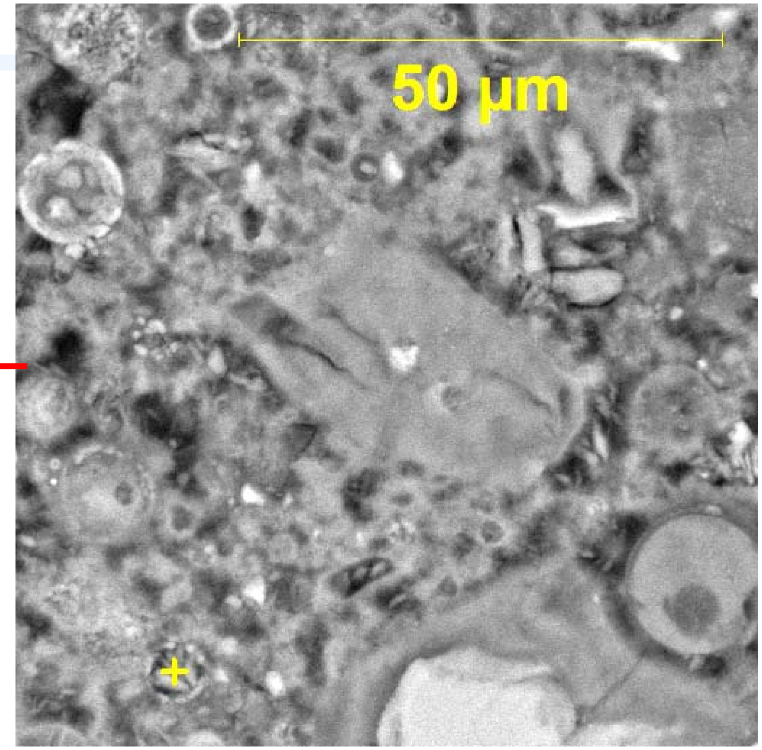




Ca-depleted cement grain near outer edge of sample

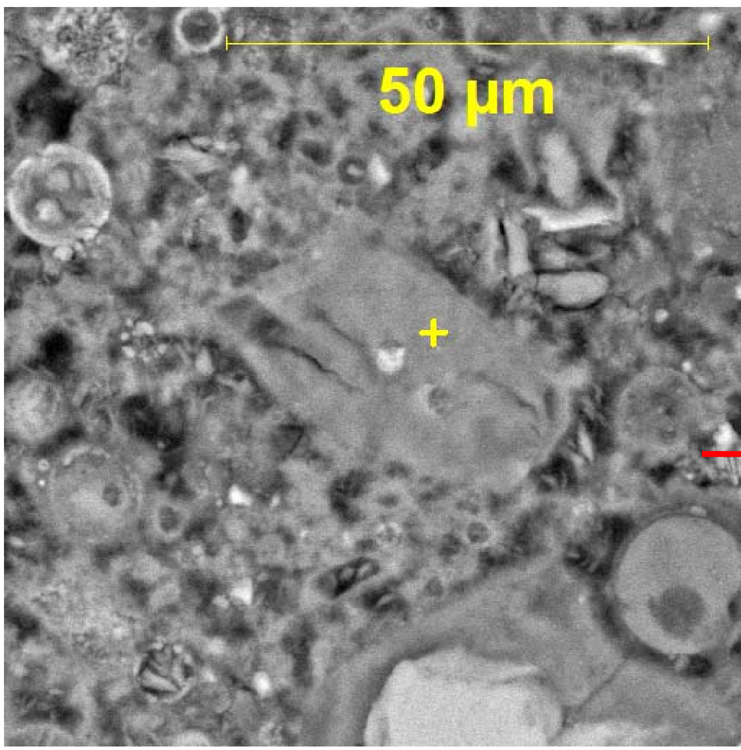
unhydrated cement grain near center of sample inside ring structure

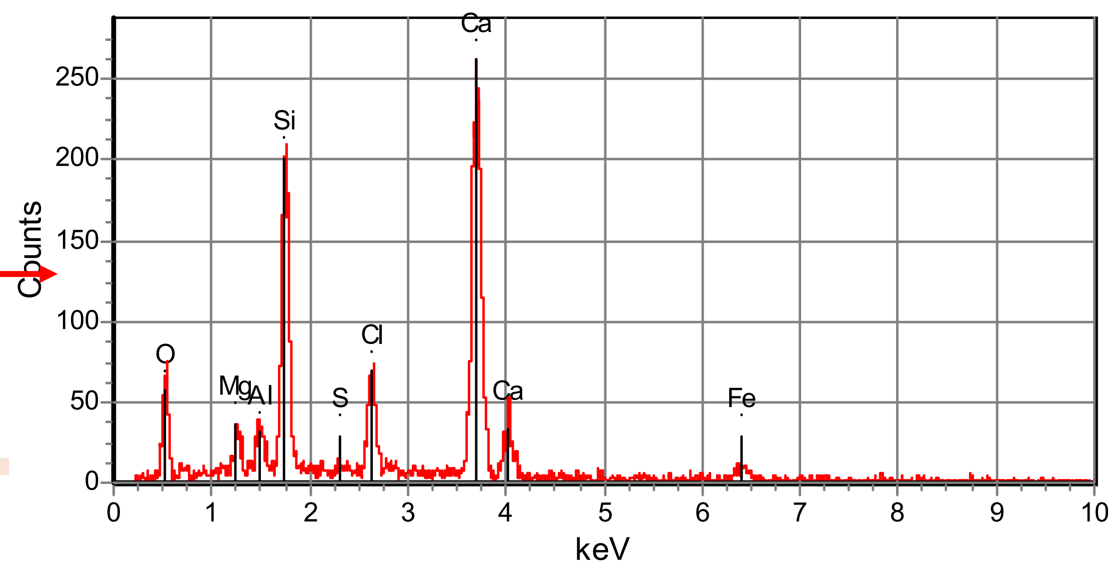


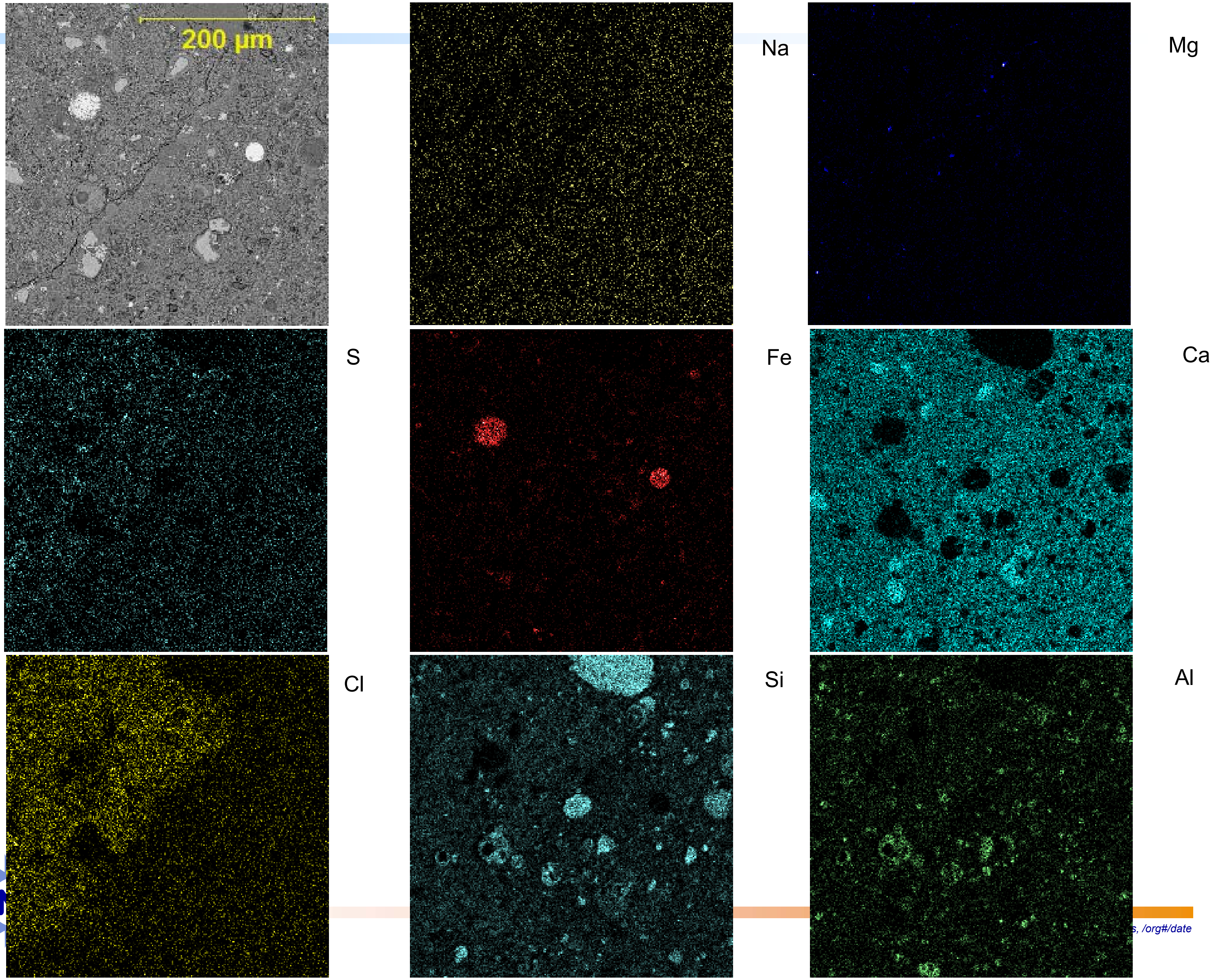


AFt with Cl, Si

interior






200 µm
Na
Mg
S
Fe
Ca
Cl
Si
Al

Core-flood and Diffusion Experiments on Wellbore Integrity of Cement and Cement-Cap Rock Composites

Marcus Wigand, J. William Carey, W. Kirk Hollis, John P. Kaszuba

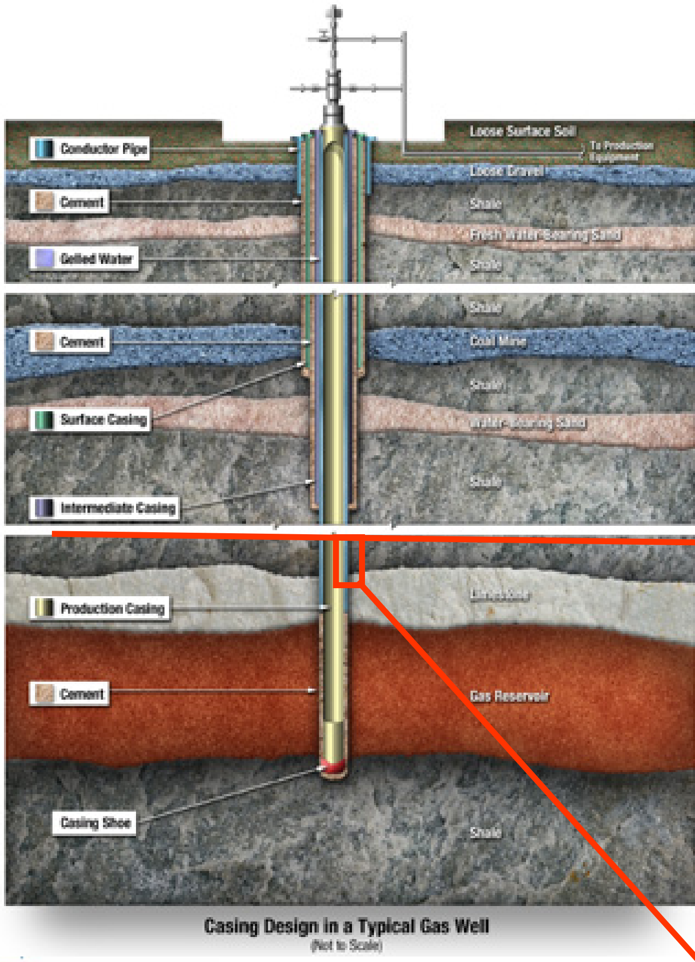
Los Alamos National Laboratory

LA-UR-071358

OUTLINE

- Introduction
- Core flood experiments on cement-cap rock composites
- Diffusion experiment on class-G wellbore cement

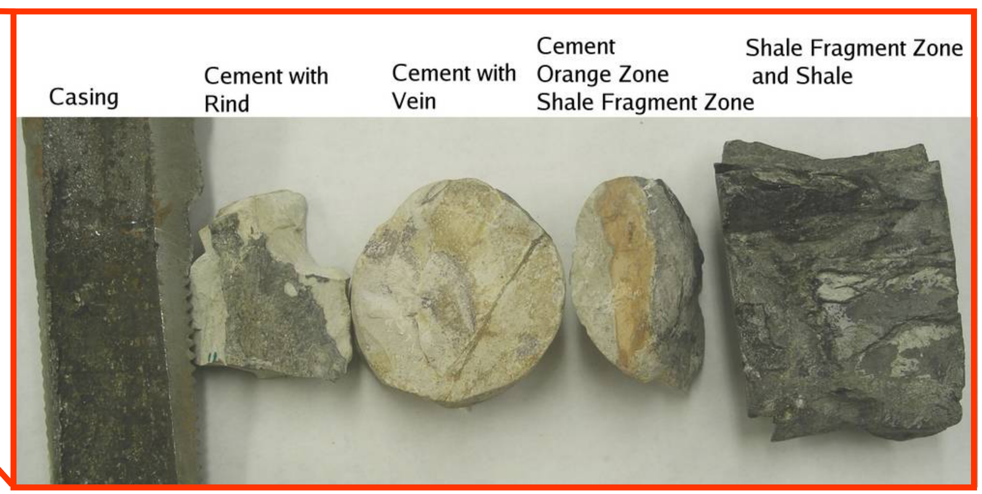
Wellbore integrity



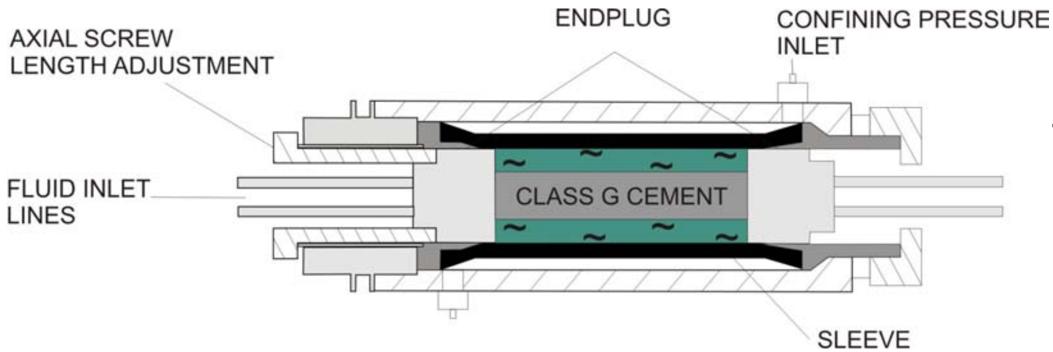
After www.envisioncreativegroup.com

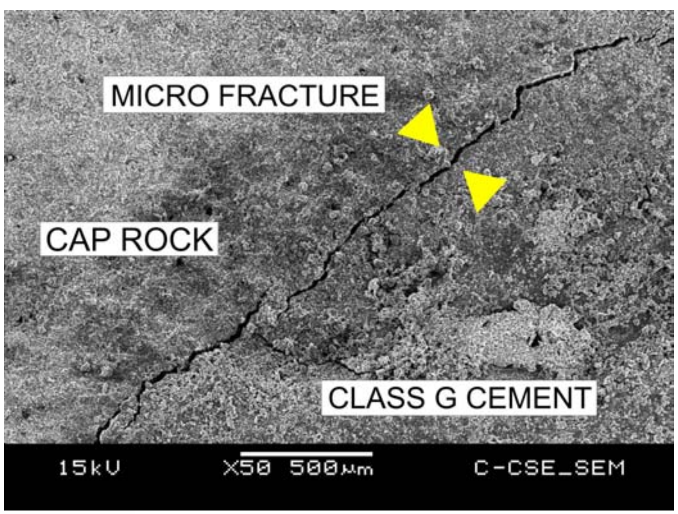
Potential risks:

- Wellbore flow
- Cement interactions with supercritical CO_2 and/or acid gases
- Cement interaction with formation brine



Flow study on micro fractures at the interface between cap rock and wellbore cement





EXPERIMENTAL SETUP:

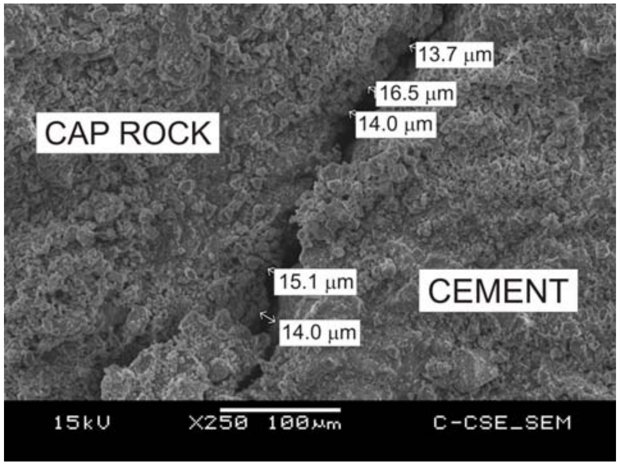
- WAG (SCCO_2 & brine)
- Hassler vessel
- Variable pore pressure
- Variable flow rates
- Confining pressure 3800 psi
- Temperature 54°C
- Fracture width 12 – 40 µm

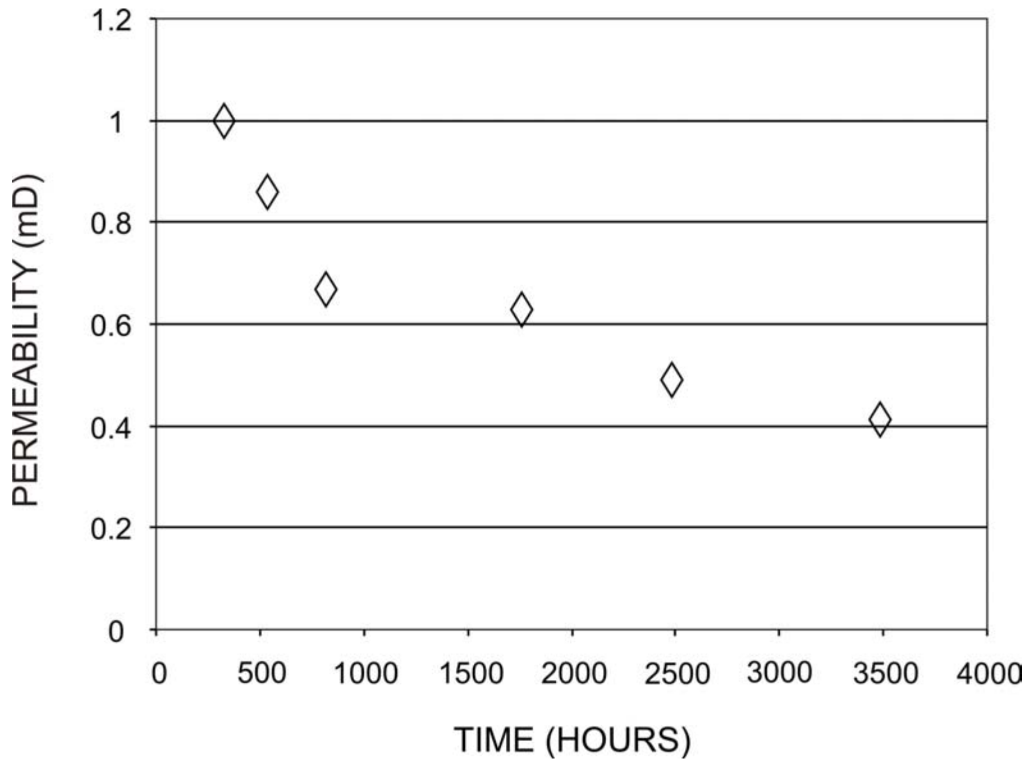
- Class G wellbore cement
- Illite-rich shale

  Clay layers oriented perpendicular to flow direction

  K_{eff} = 5 nDarcy

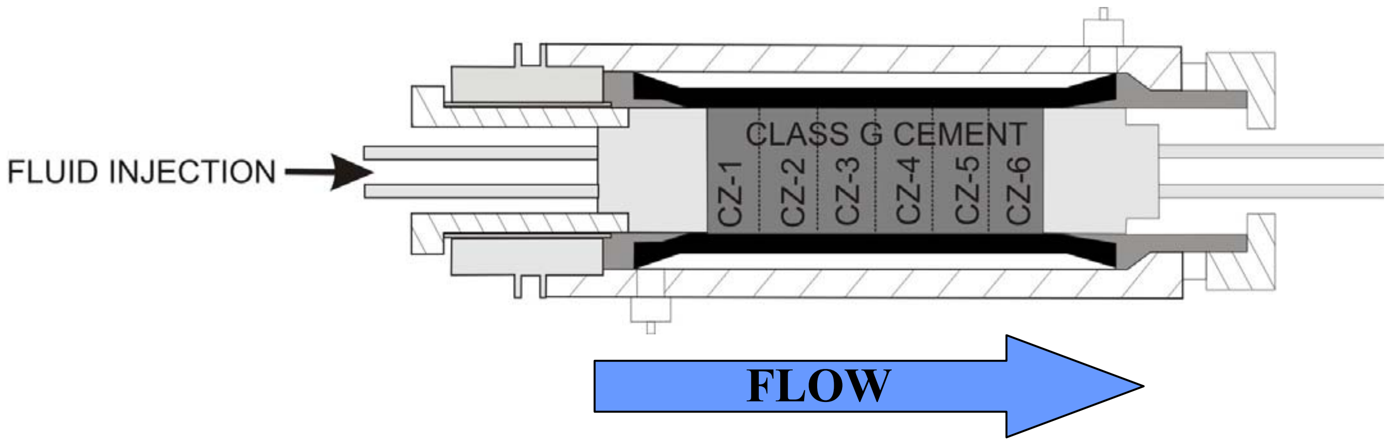
Flow study on micro fractures at the interface between cap rock and wellbore cement





Decrease in permeability over time !

Diffusion studies on class G wellbore cement using supercritical CO_2 and brine



EXPERIMENTAL SETUP:

Hassler vessel

Injection pressure 2880 psi

Pressure gradient 40 psi

Confining pressure 3800 psi

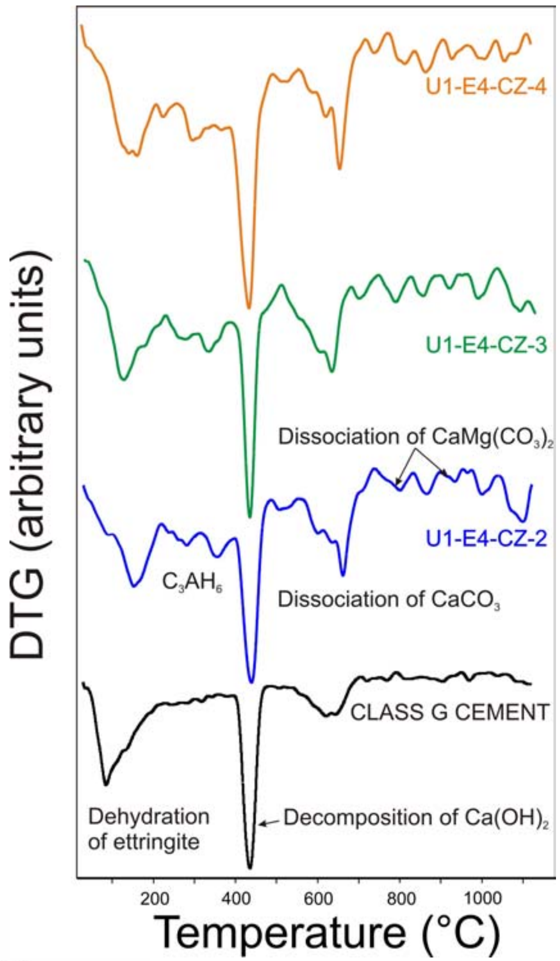
Temperature 54°C

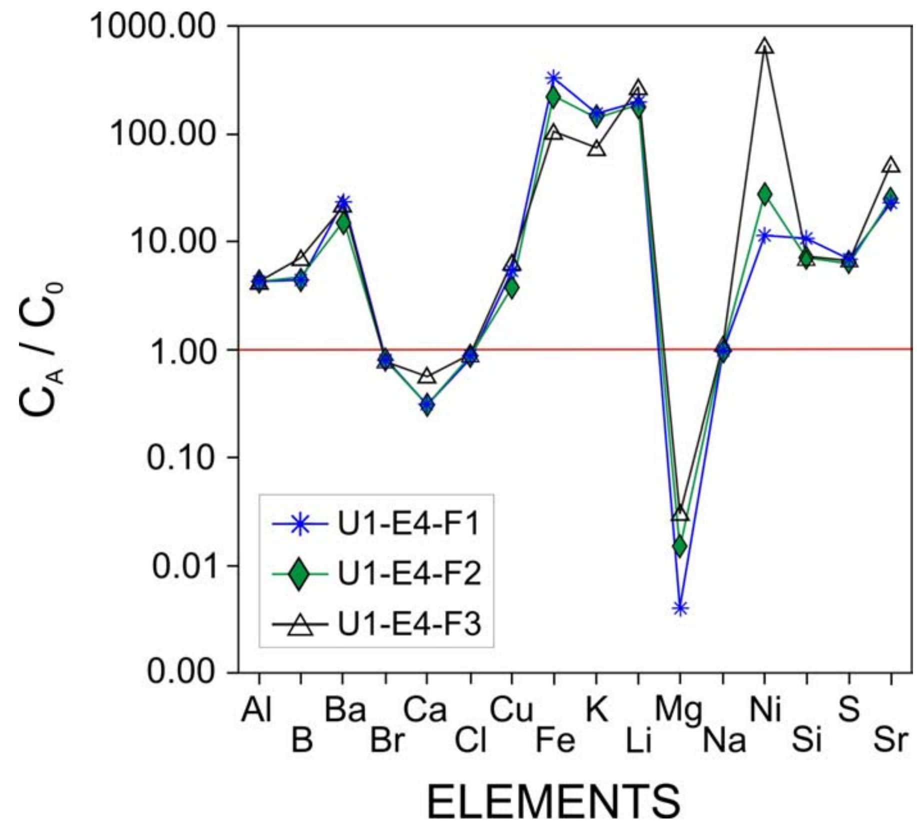
PROCEDURE

Saturation with 3 M brine over 31 days

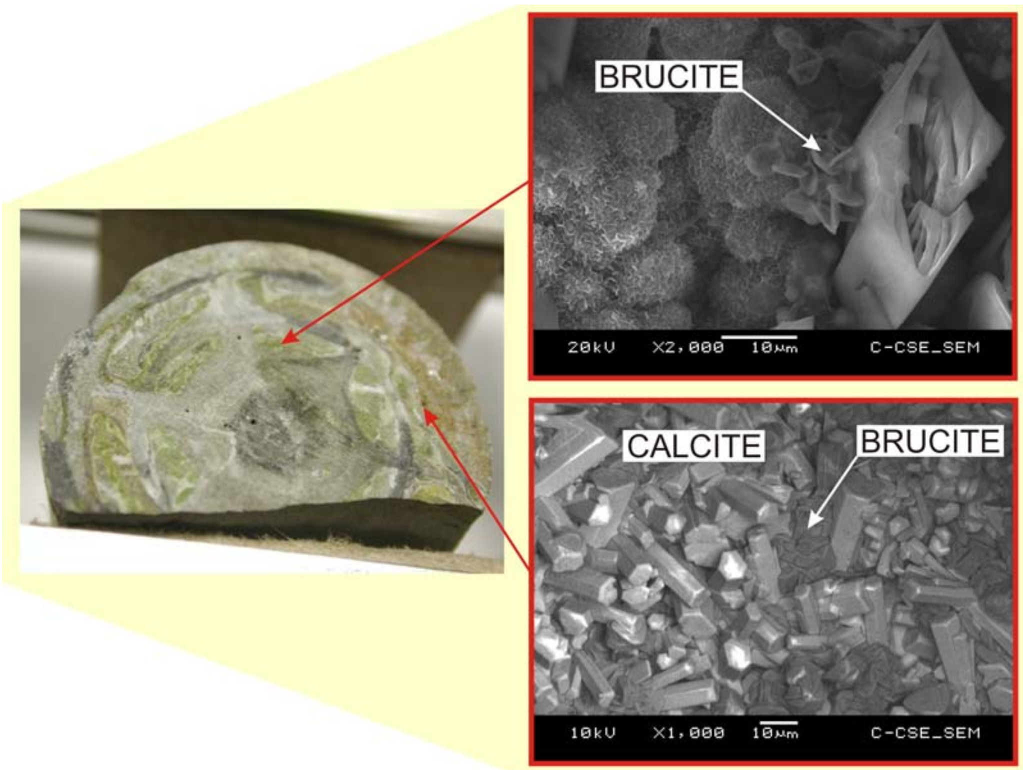
Injection of SCCO_2 over 141 days

Diffusion studies on class G wellbore cement using supercritical CO_2 and brine





Diffusion studies on class G wellbore cement using supercritical CO_2 and brine



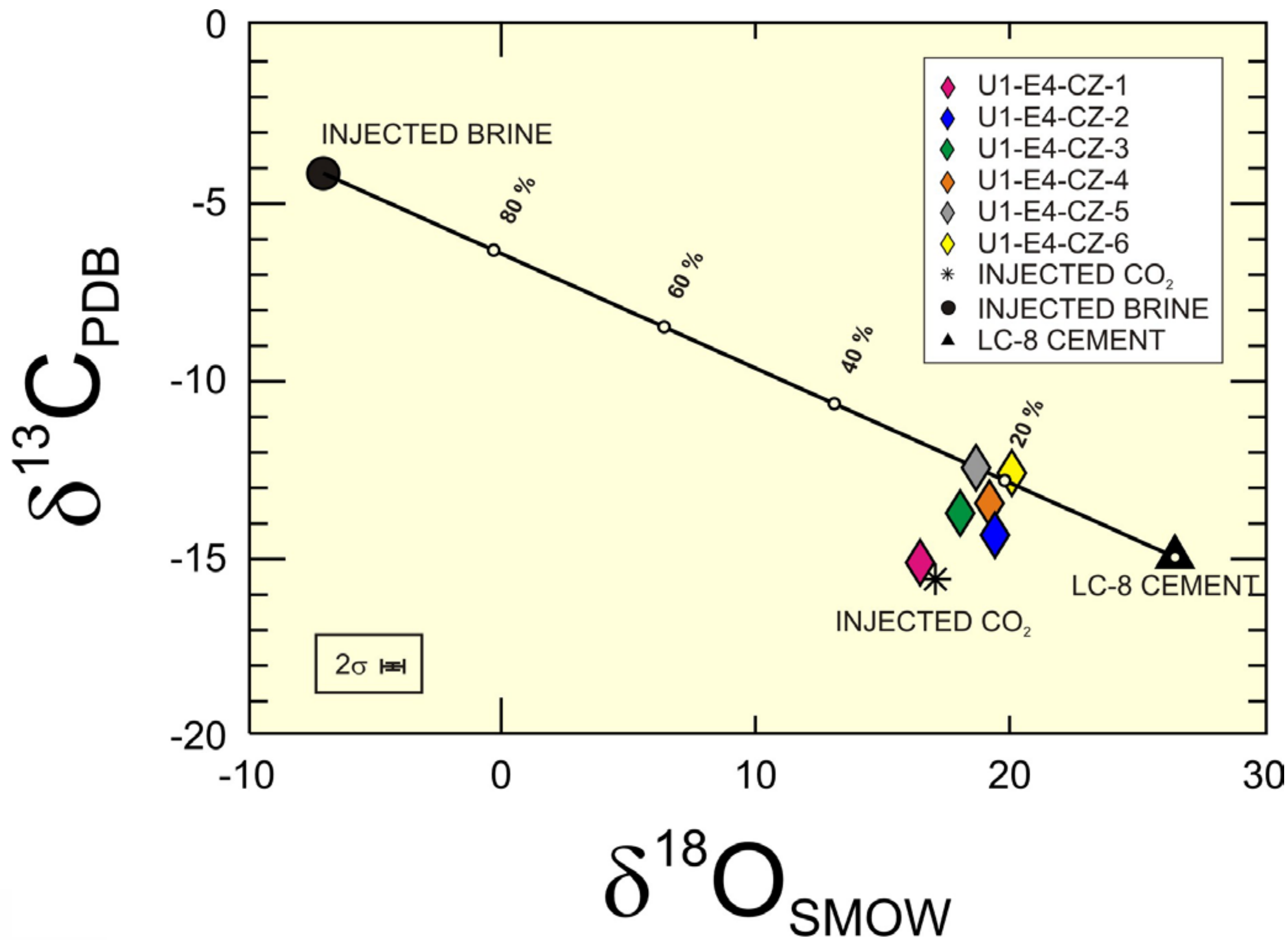
XRD RESULTS:

CEMENT PHASES	wt%
Portlandite	15
Brownmillerite	9
Hydrocalumite	7
Katoite	6
Ca_2SiO_4	7
Ca_3SiO_5	4
Calcite	6
Aragonite	2
Brucite	4
Amorphous	40

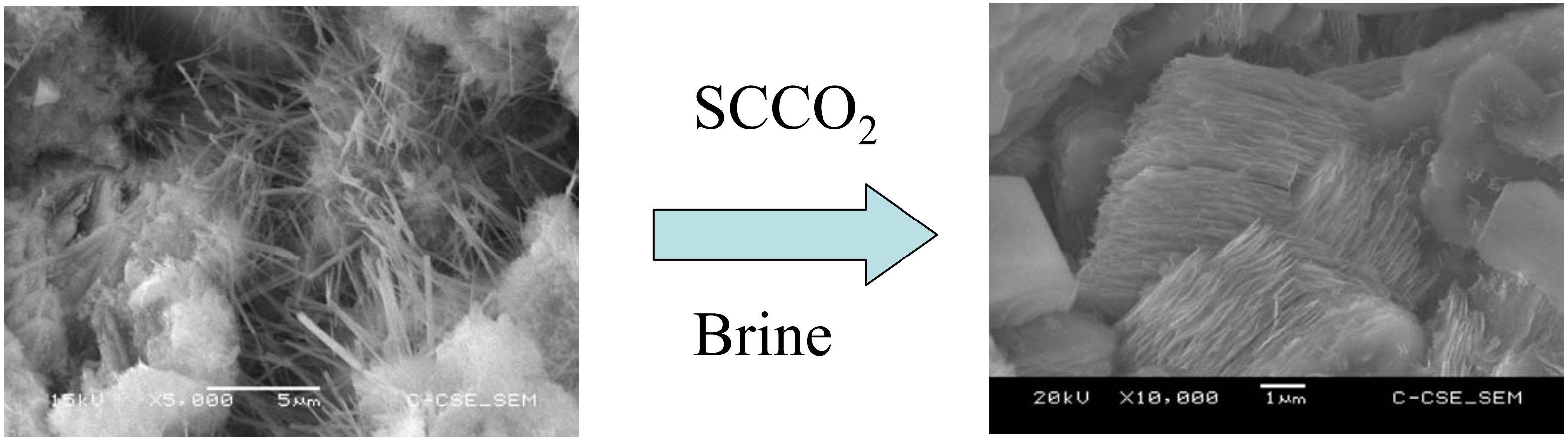
ACR-TYPE REACTION ("DEDOLOMITIZATION"):

$$CaMg(CO_3)_2 + Ca(OH)_2 \longrightarrow Mg(OH)_2 + 2CaCO_3$$

Stable isotopes as an indicator for the carbonation process of the wellbore cement



Diffusion studies on class G wellbore cement using supercritical CO_2 and brine



- Changes in the texture of the cement but no formation of an orange-colored carbonation zone
- Portlandite and C-S-H phase are still present after $SCCO_2$ treatment

Conclusions

- Decrease in permeability at the interface cement/ cap rock may indicate that small fractures are able to heal over time
- Not every Portland-based wellbore cement shows a complete carbonation during the reaction with $SCCO_2$ & brine
- ACR-like processes can occur during carbon sequestration processes
- CO_2 does not appear to have penetrated through the length of the core (2.39 cm) during the 172 day experiment
- No formation of an orange alteration zone
- Portlandite and C-S-H present throughout the core

Fluids

- Geochemical calculations show that carbonates are very undersaturated, if a high CO_2 pressure is assumed

- Fluid Chemistry: Combination of high ionic strength and uncertain degree of equilibration/exposure to CO_2 make interpreting mineral stabilities difficult

- All consistent with a lack of significant CO_2 penetration into the core

Thank you very much for your attention !

Core Flooding Applications For Limestone and Cement Composite Cores

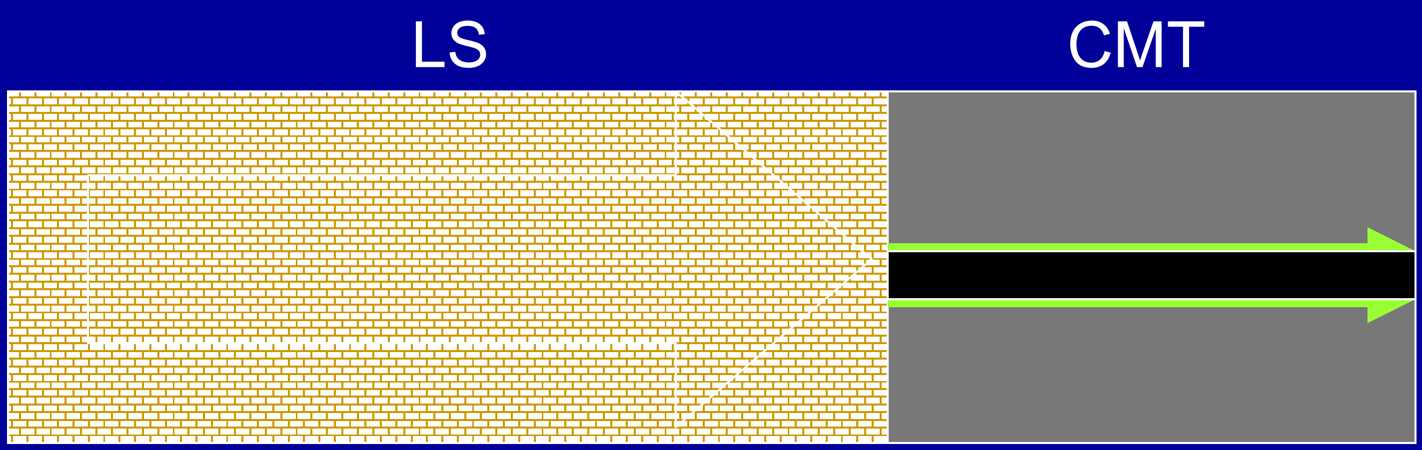
Bob Svec and Reid Grigg

New Mexico Tech
Petroleum Recovery Research Center — a research division

Supported by US DOE and the State of New Mexico

Objective

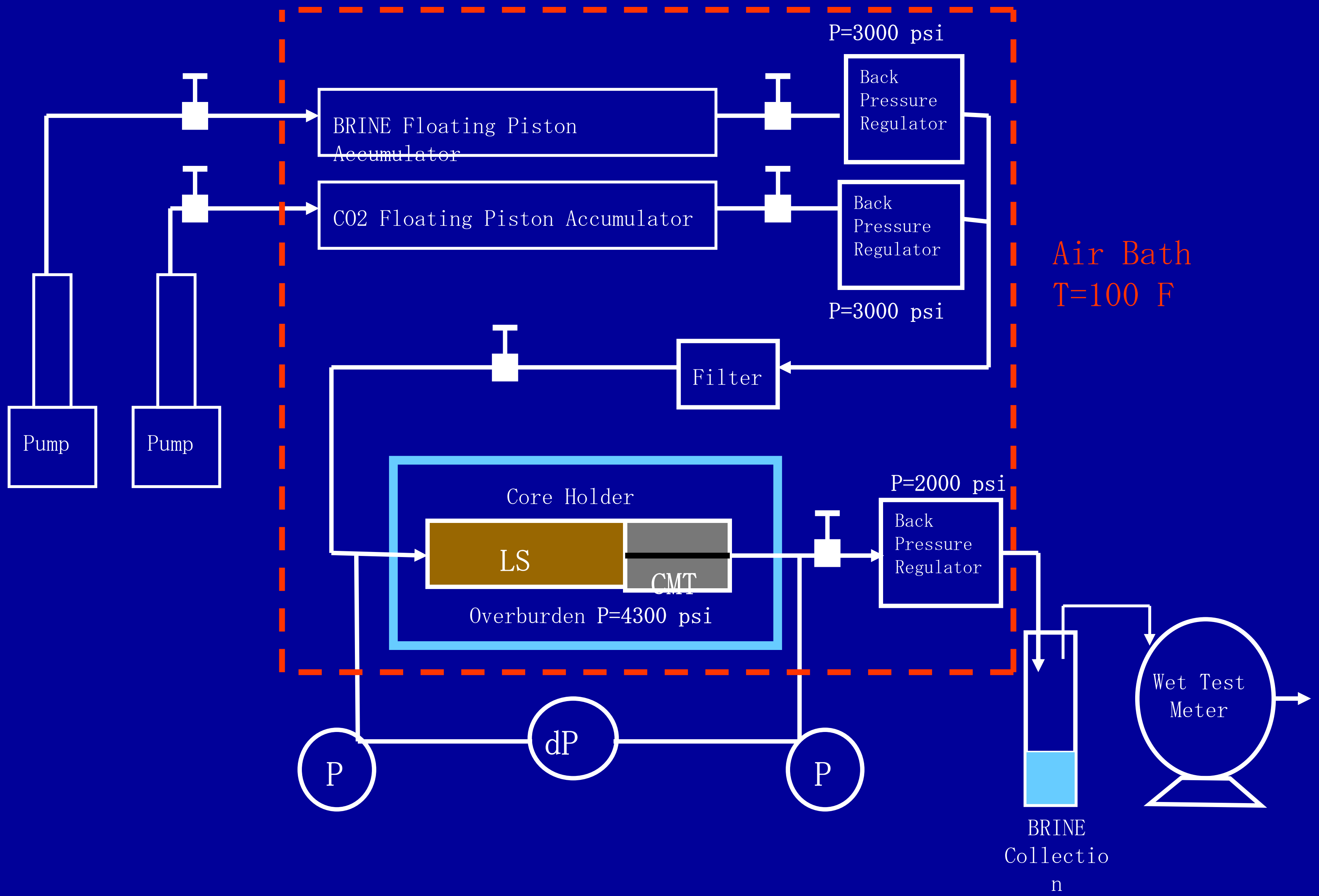
- Study the interaction of co-injected brine and supercritical CO_2 with a composite core of limestone and cement containing well casing. Flow thru the cement should be constrained to the casing interface.



Experimental parameters

- LS: L=26.83cm D=5.02cm Phi=0.18
- CMT: L=6.34cm D=5.09cm
- Composite Pore Volume=91.47cc
- Casing Channel Volume=0.15cc
- Apparent Micro-porosity (CMT?) V=0.9cc
- Co-injection, Brine=10cc/hr, CO_2=10cc/hr, later decreased to 5cc/hr each.
- P_{pore}=2000psig, P_{ovb}=4300psig
- Temp=100 F

Core flooding system



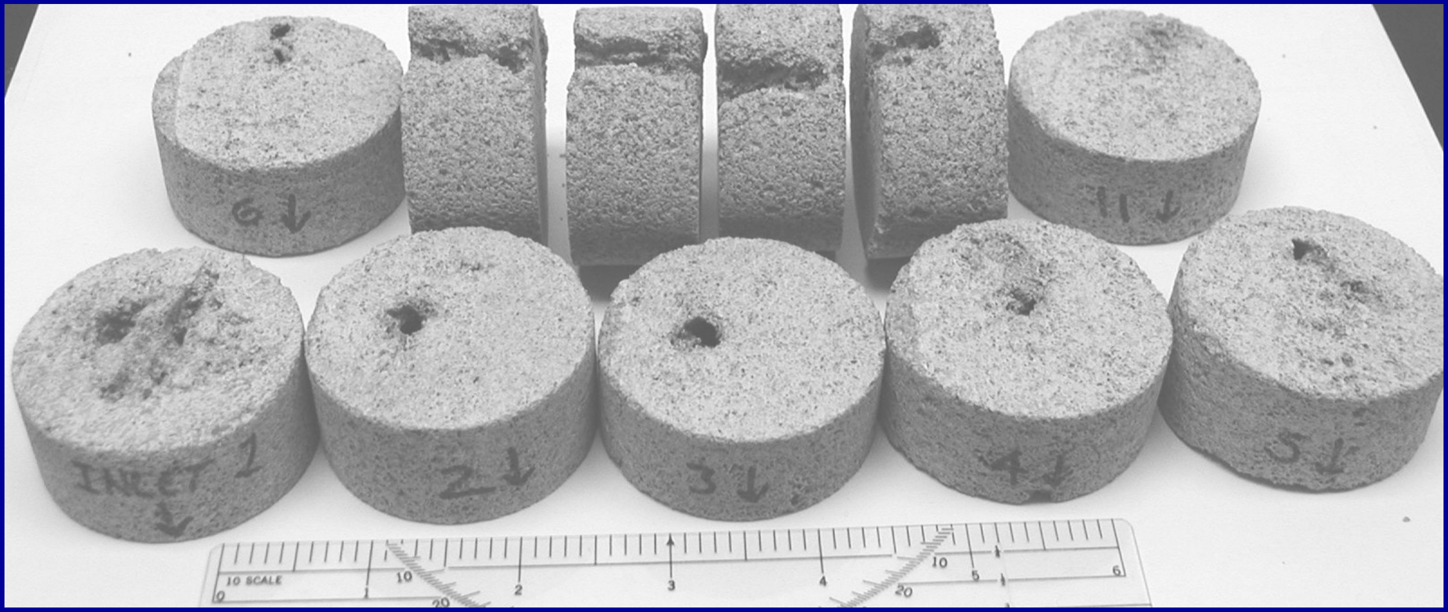
Brine composition

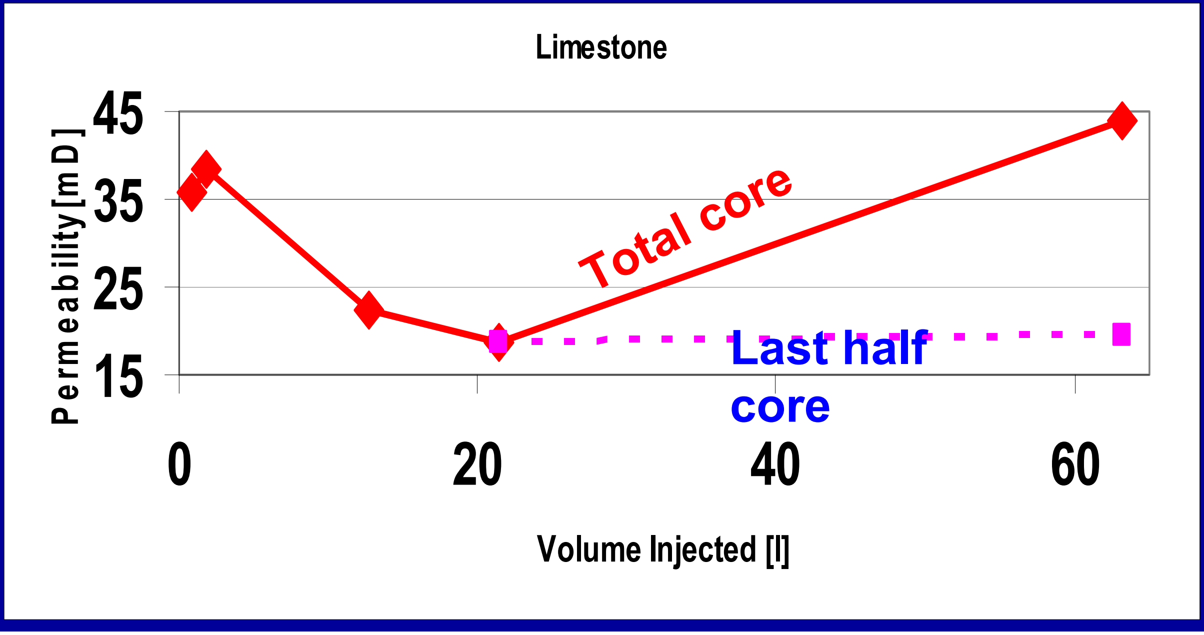
	Reservoir Brine #1	Reservoir Brine #2	Brine #3 Tracer #1	Brine #4 Tracer #2	LS/CMT
NaCl	64700	13531	10000	25000	25000
$CaCl_2$	11000	4330	5000	4040	4000
$MgCl_2$	3810	1914	5000	190	1000
$NaHCO_3$	1850	5645			
$Na2SO_4$	5590	4831			
$MnCl_2$			5000	198	200
$SrCl_2$			5000		
TDS	86950	30251	30000	29428	30200

Survey of Permian Basin reservoirs revealed a general trend of about 4:1 for Ca:Mg, even in many producing limestone formations.

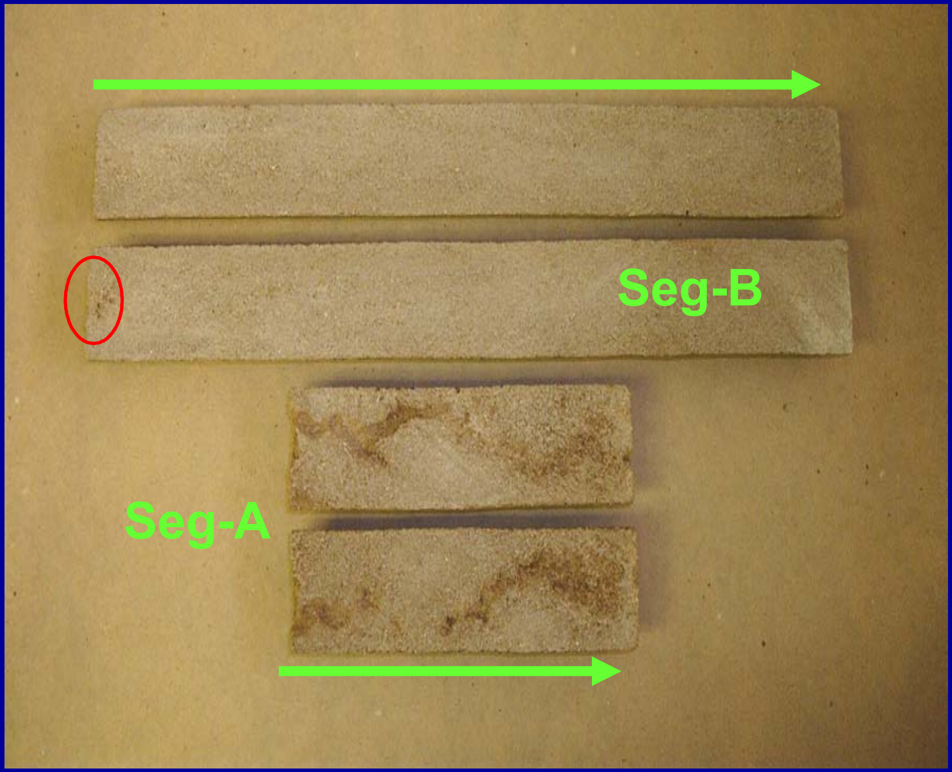
Manganese salt added as tracer element to help identify any minerals deposited during the core flood.

Solution channel in WAGed limestone

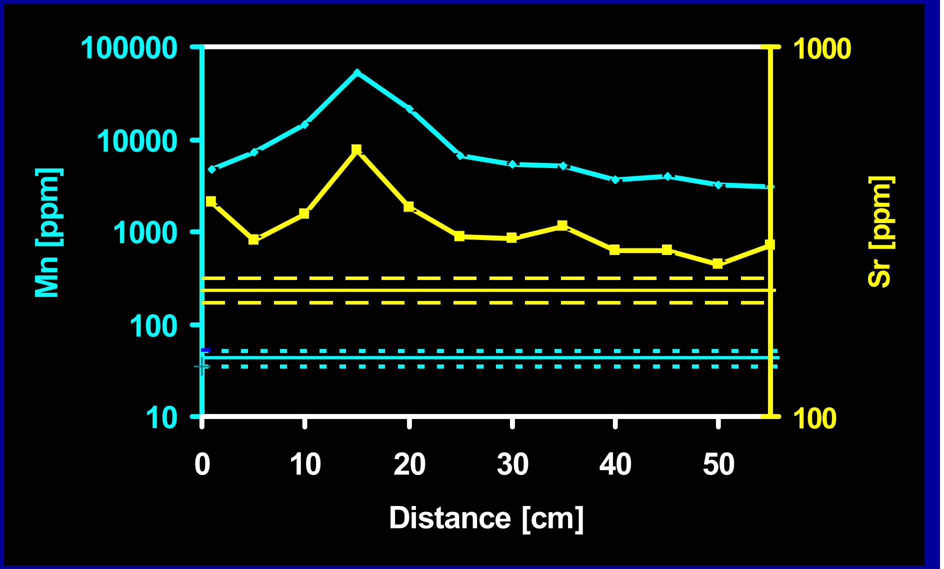




Limestone Co-injected with tracer



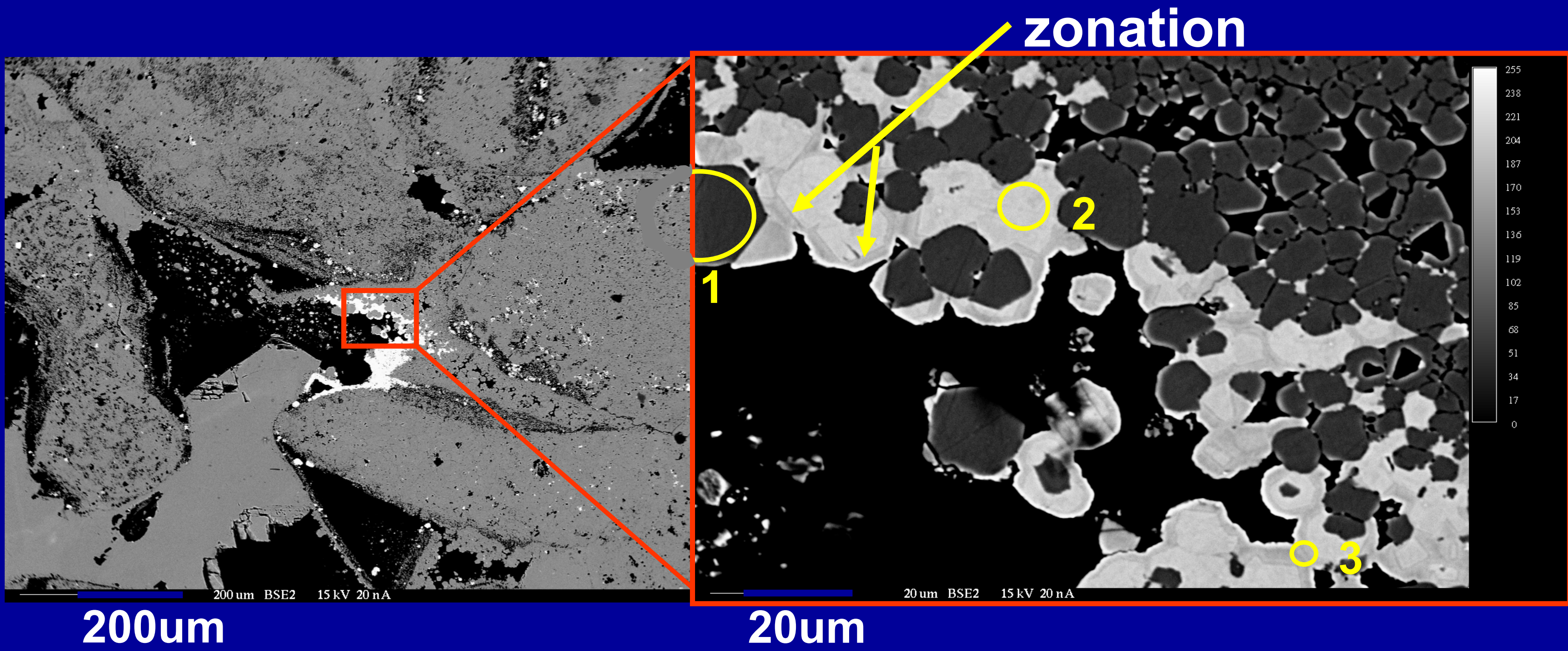
Mn and Sr Concentration
Chemical Analysis (bulk core)



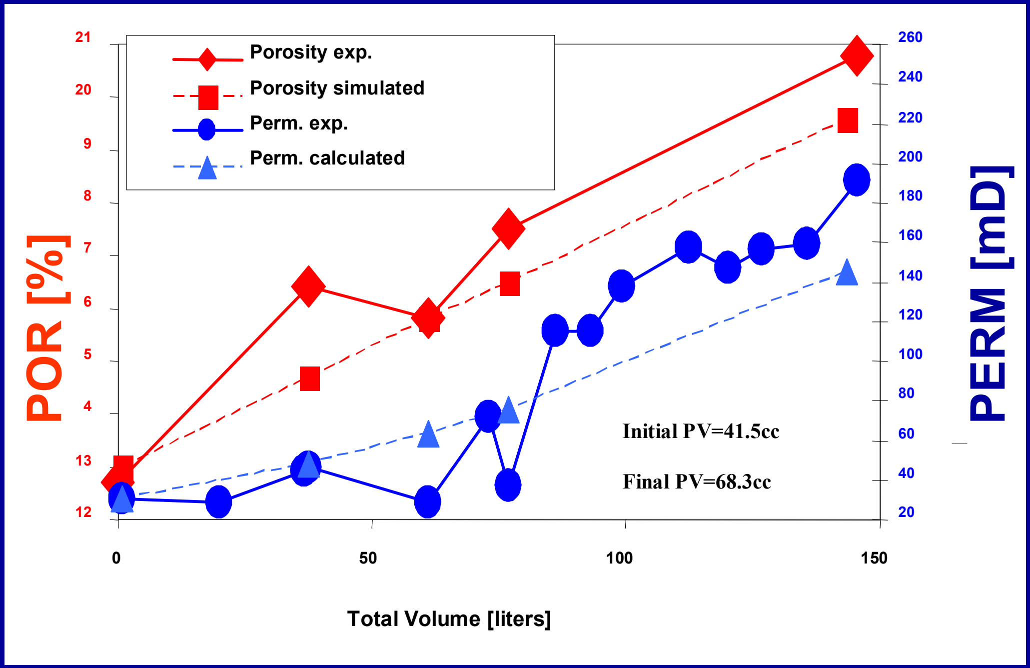
Mn tracer example

Quant BSE analysis [% as carbonate]

	Ca	Mg	Mn	Sr
1.	98.7	0.65	0.62	0.00
2.	35.2	0.32	64.1	0.20
3.	19.4	0.30	79.7	0.28



Dolomite response to WAG



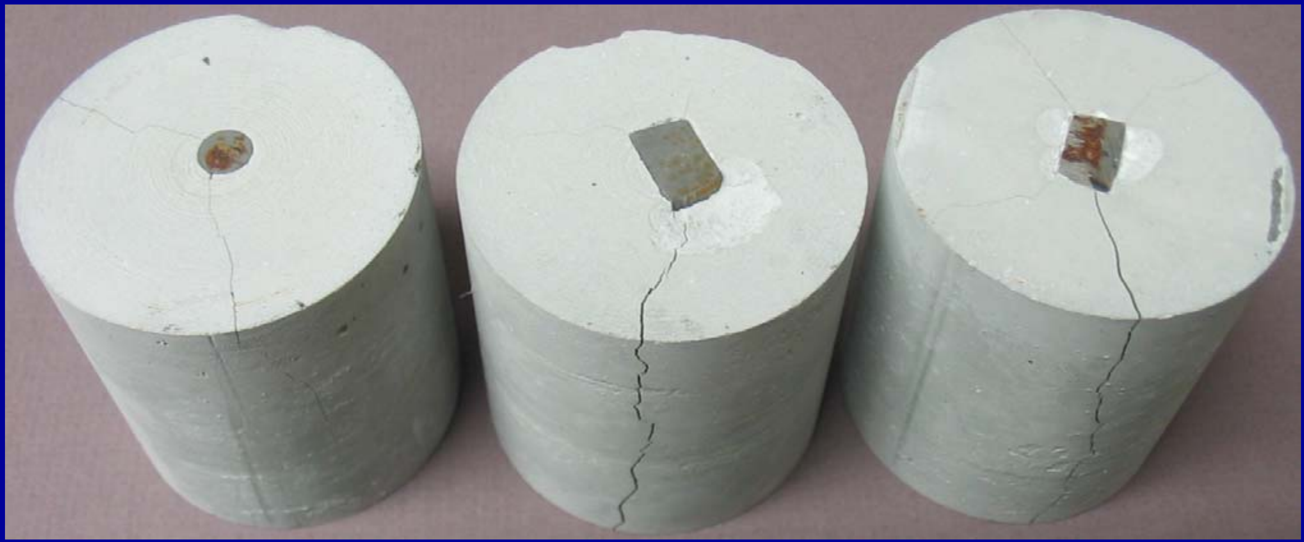
Cement core fabrication

Cylindrical and rectangular well casing coupons, machined to a slight taper. Rectangular pieces retain original finish.

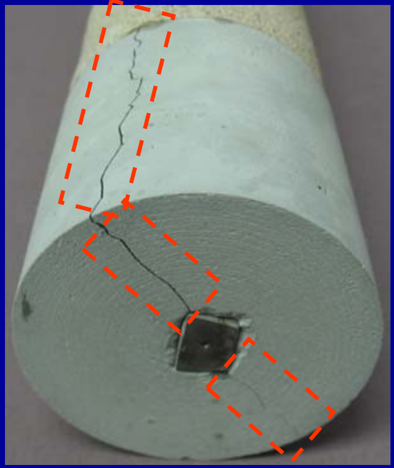
Casing cast into hydraulic well cement. Allowed to set for 24 hours in mould.

Cement cores as cast and as machined to final form. Cement is still damp. Casing is loose fit and may be removed.

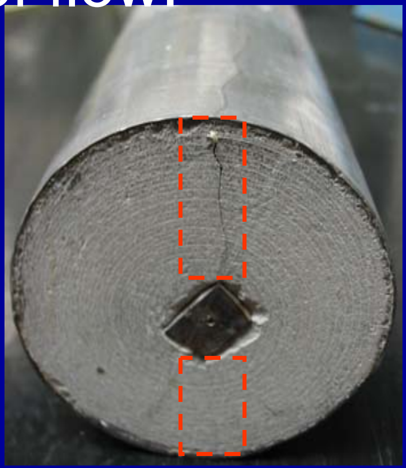
Cement cores after drying in air for one week.



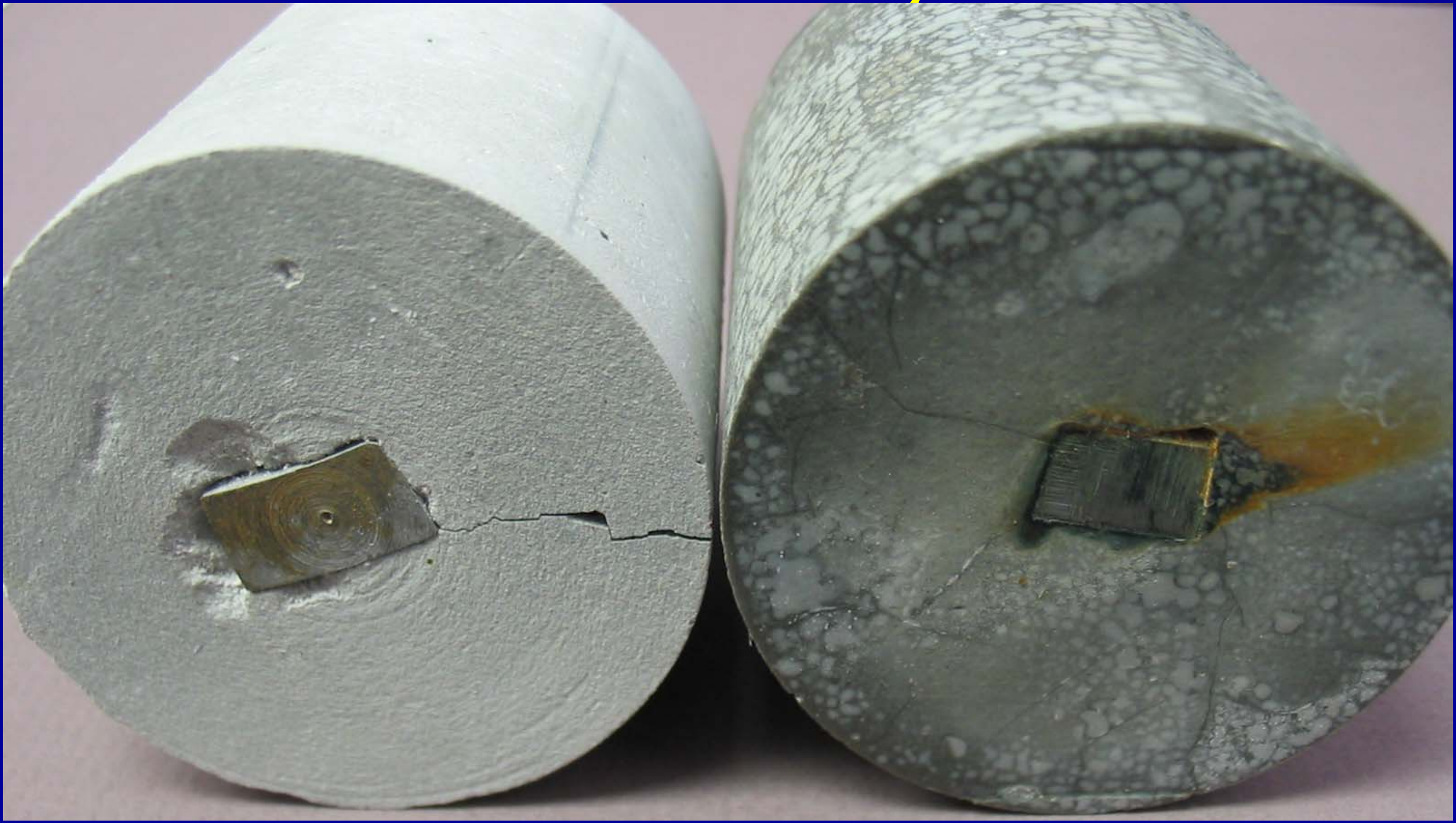
LS/CMT composite assembly ready for installation. Cement fracture apparently open for flow.



LS/CMT composite removed from core holder. Has overburden pressure and reintroduction of brine closed the fracture aperture? Core held 2000 psid with no indication of flow.



Cement sensitivity to brine



Cured cement core allowed to air dry and fracture.

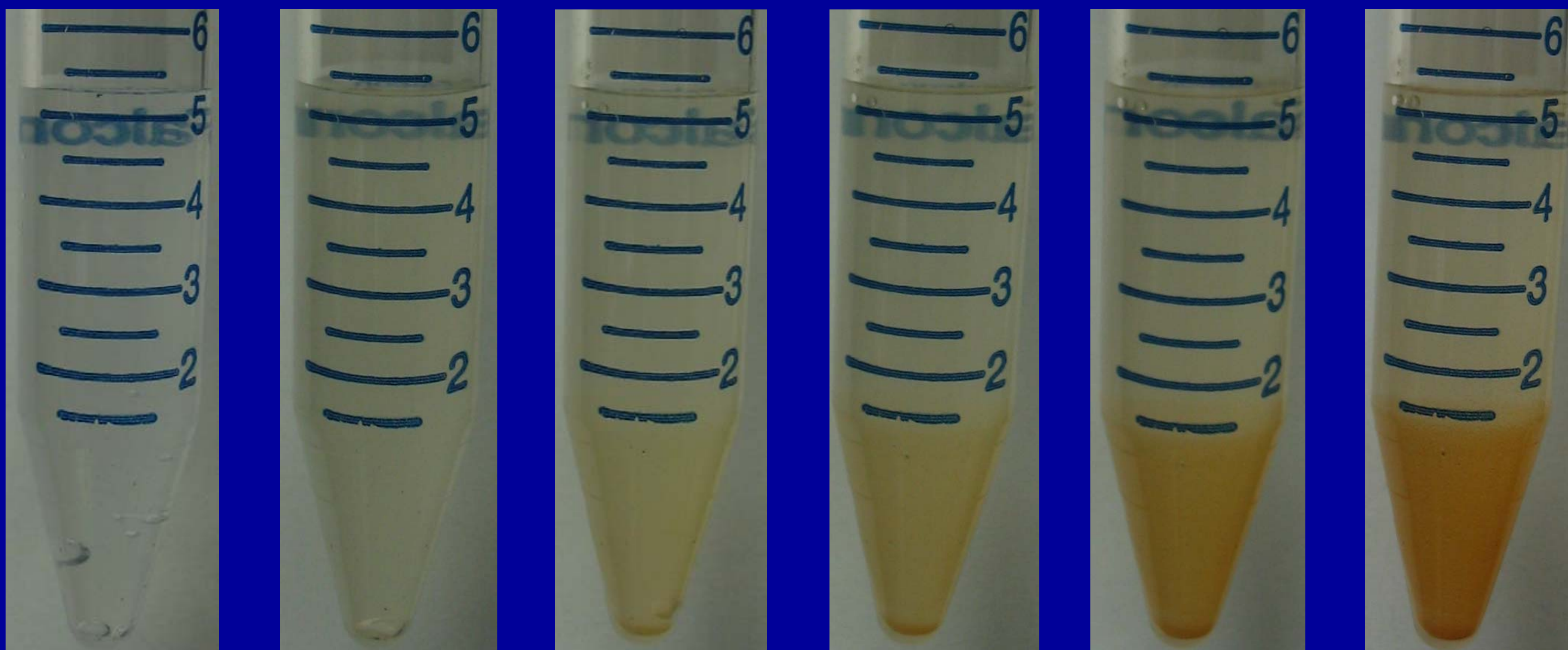
Core from the same batch, had several similar fractures. Soaked in brine for seven days. Fractures have apparently closed.

Cement core modification

1. Cement cured for 30 days in $Ca(OH)_2$ solution.
2. Casing removed and modified with 7 shallow parallel channels.
3. Casing replaced and CMT composited with LS as before.
4. Cement not allowed to dry, no fractures.

Effluent samples

- Heavy mineral loading of effluent: immediate drop out of white solid in system plumbing then further precipitation of brown solids in water samples.

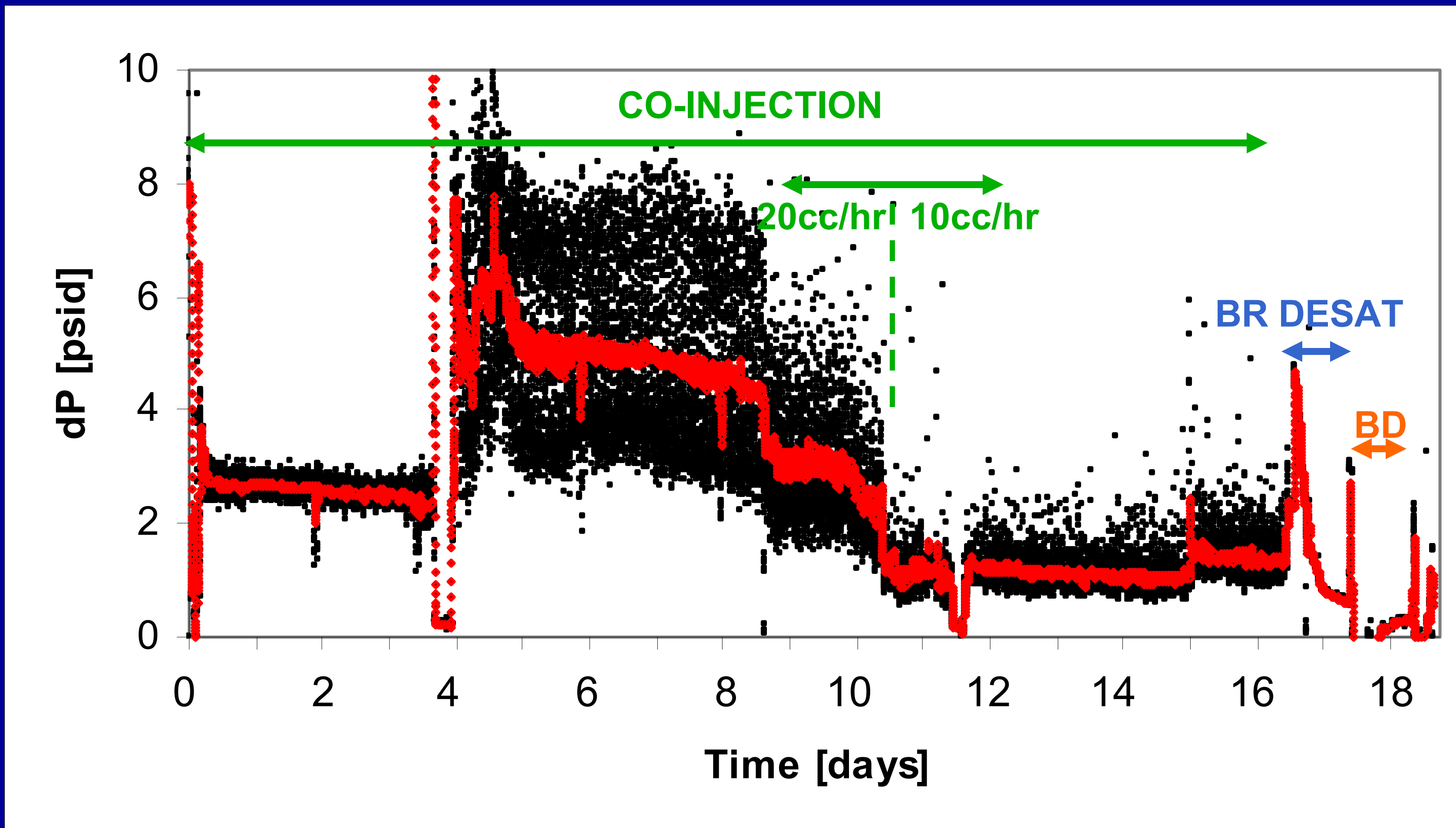


T=0 hr T=4 hr T=8 hr T=12 hr T=24 hr T=36 hr

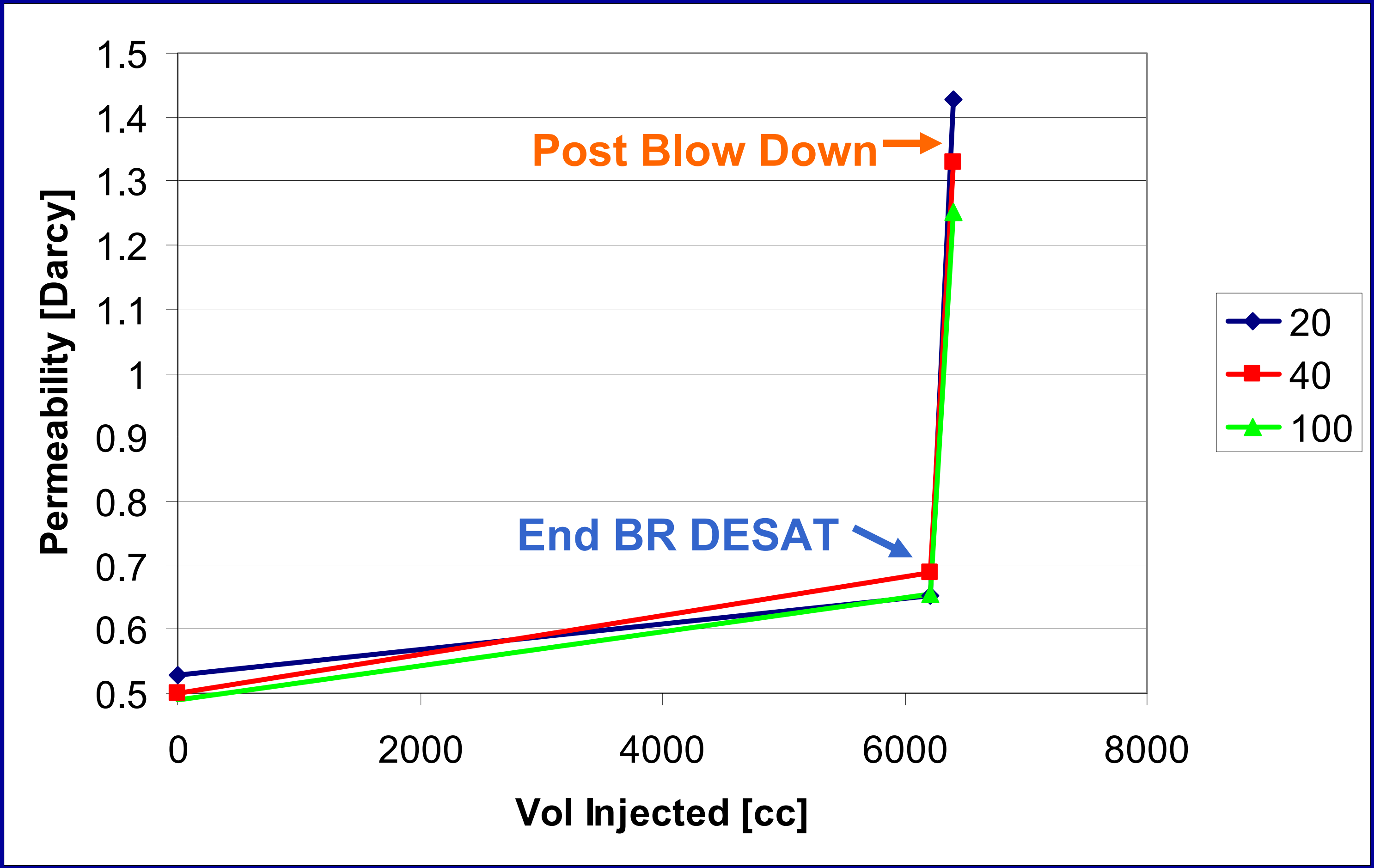
Results

- Exposure time to brine and supercritical CO_2 is 394 hrs. Includes a few stop-flow periods for equipment repairs.
- Volume of co-injected fluids is 6210.6cc.
- Scaling to the pore volume of the casing channels (0.15cc) this is 41404 PV of flow.

Core flood differential pressure



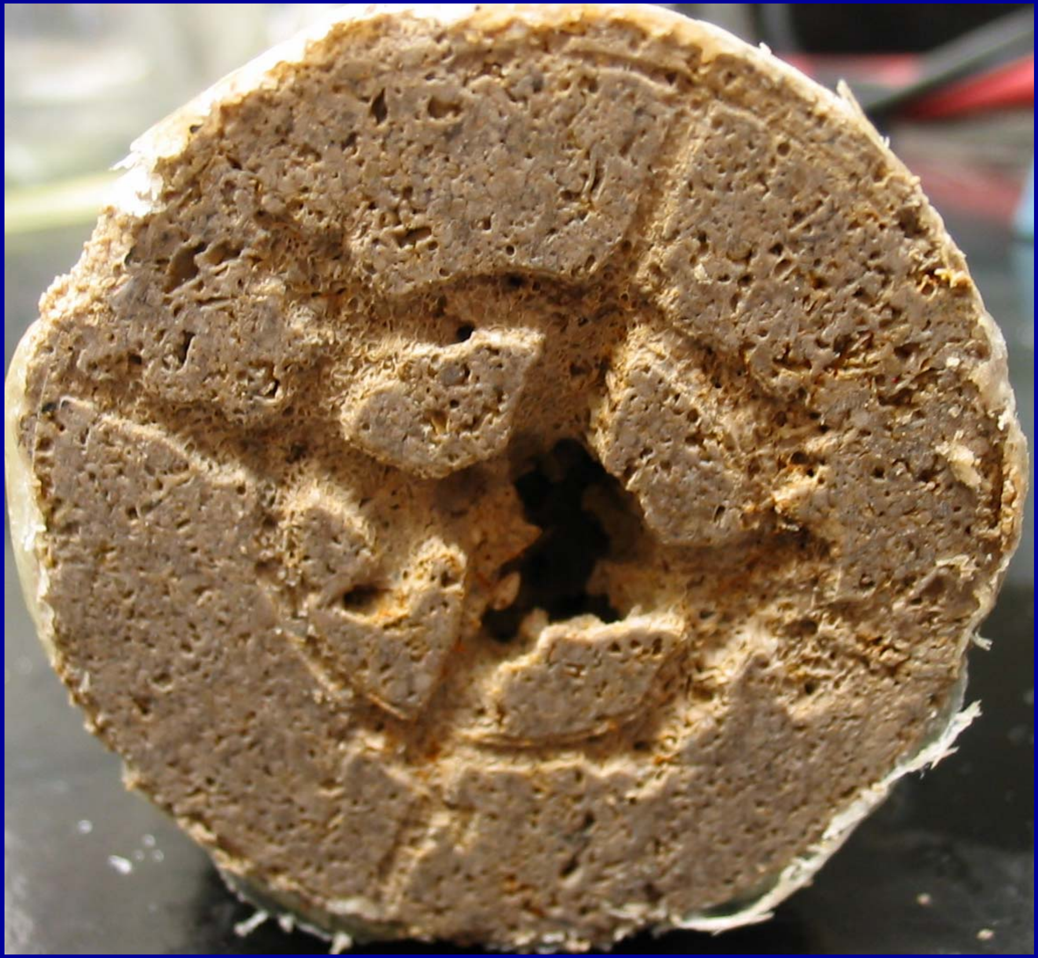
Composite core permeability



Is solution compensated by plugging of insolubles?

Were plugged pore throats cleared by reverse flow blow down?

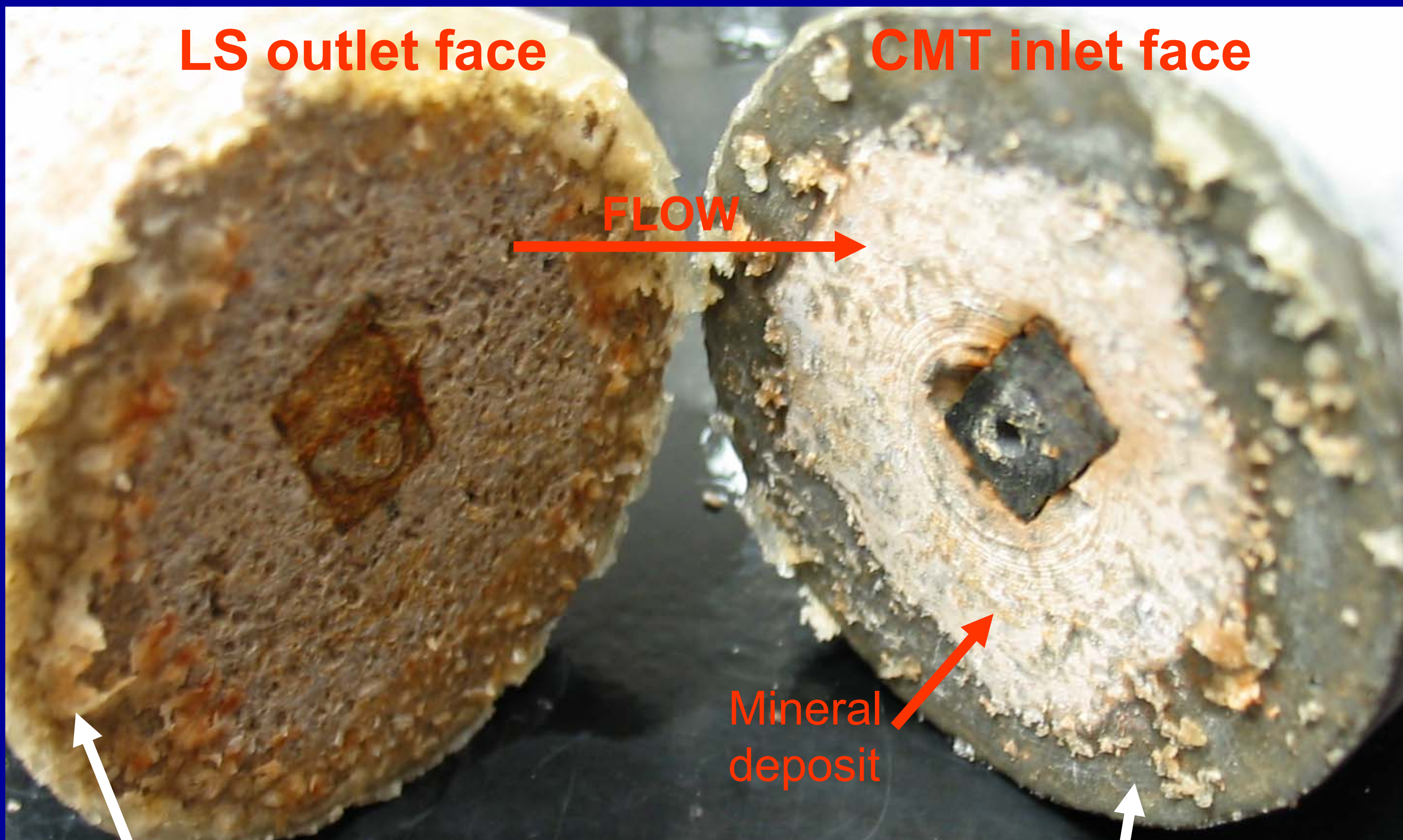
Post-flood core



LS inlet face

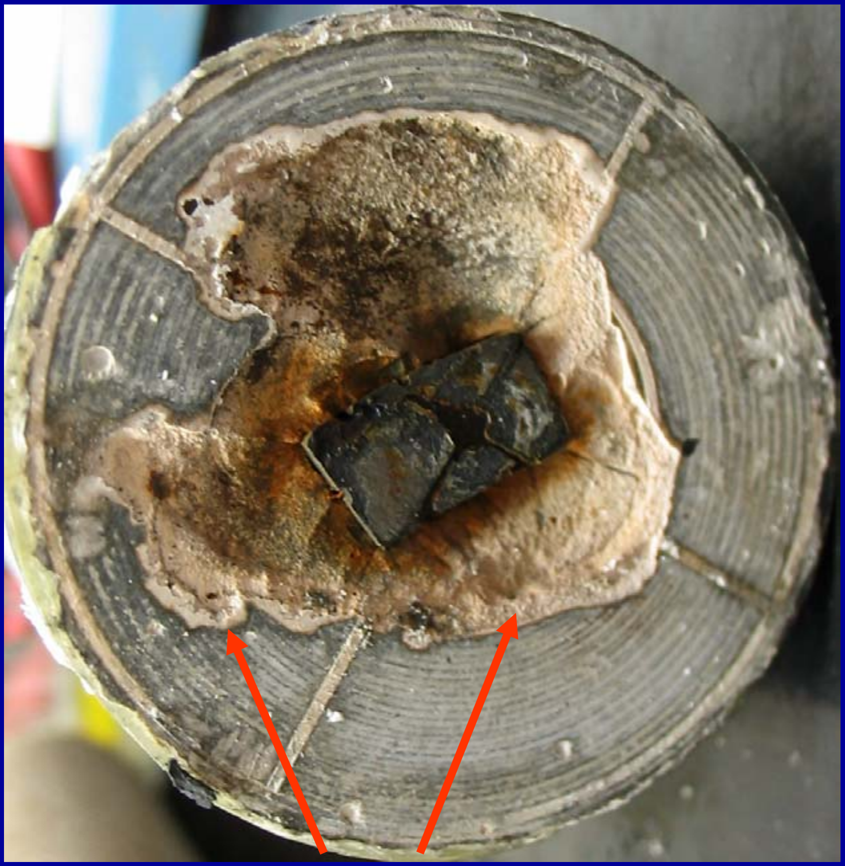
Post-flood core

Post-flood core



Post-flood core

Pre-flood state



Some enlargment of zone, white mineral deposit, and rust stain.

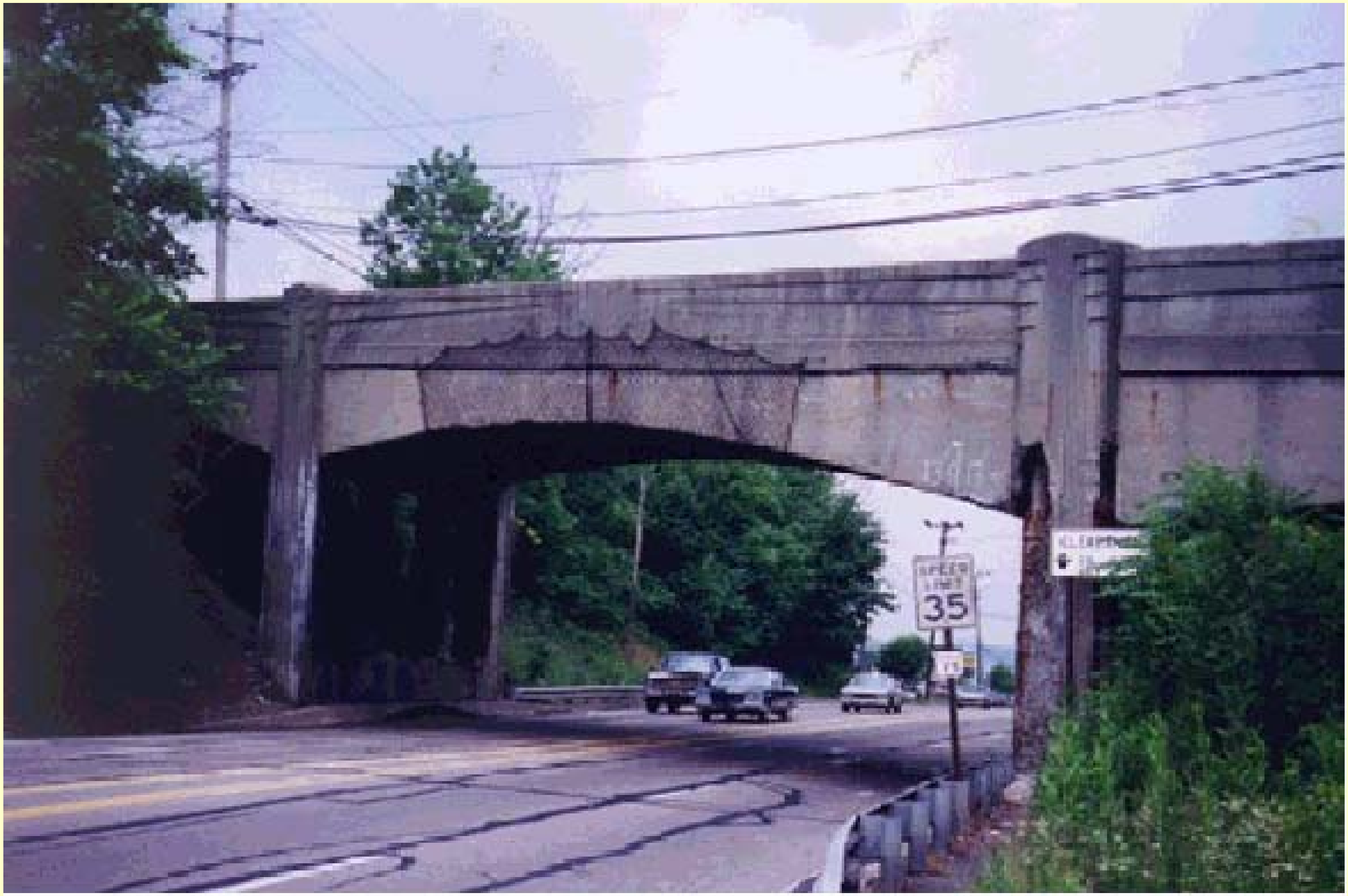
Work in progress

- LANL has cement core, to be sectioned and examined by SEM and for cement carbonation.
- NMT has limestone core, to be sampled for wet chem analysis and BSEI imaging.
- Effluent brine samples to be analyzed for major elements.

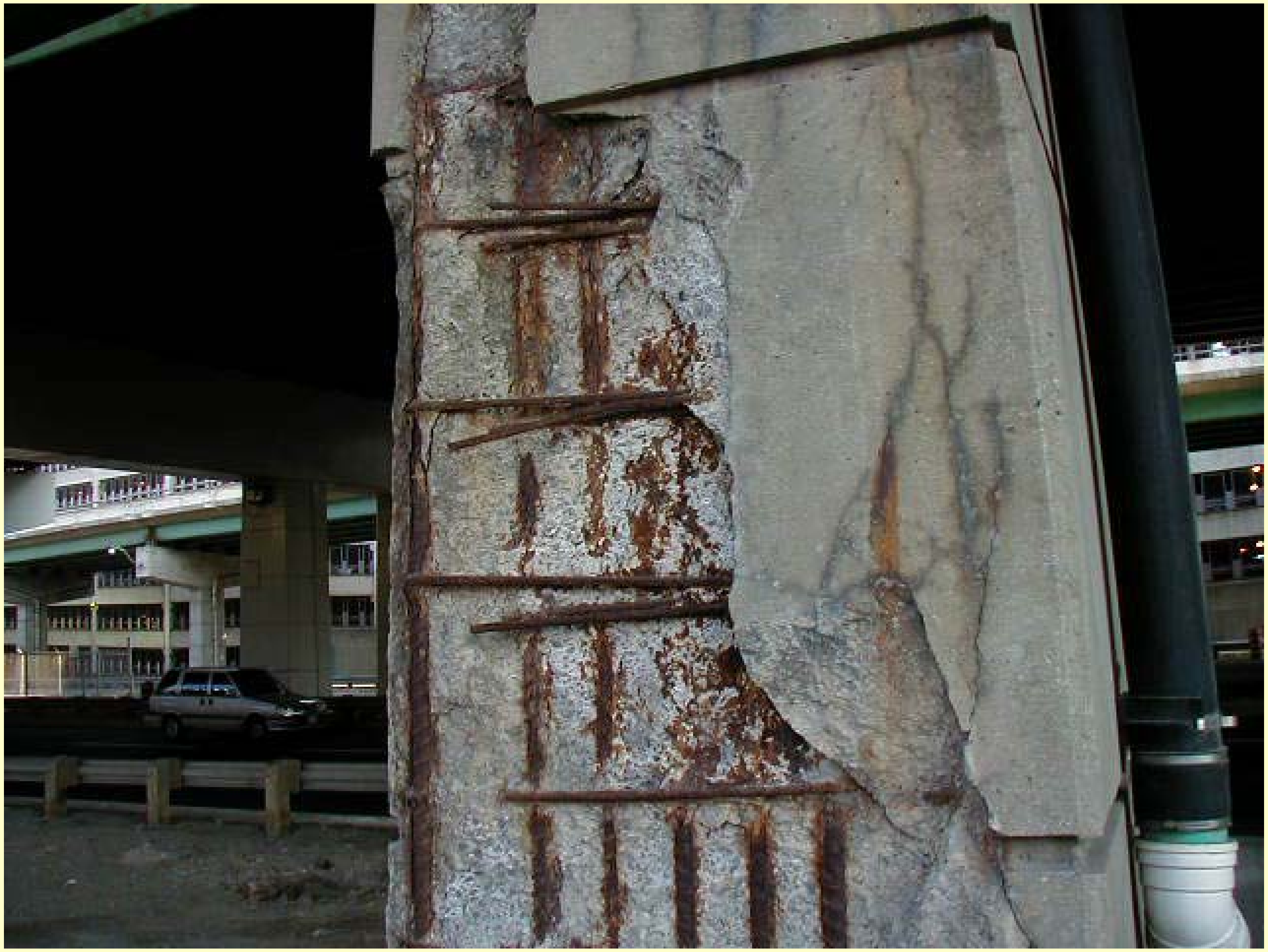
Carbonation of Concrete Structures

N. Thaulow
RJ Lee Group Inc.
Monroeville, PA 15146
USA

12 March 2007


SPEED LIMIT
35

Deleterious Carbonation



Hoover Dam

650 year old Bridge

50 year old Bridge

Carbonation Reaction Process

$$CO_2 + OH^- \rightarrow HCO^-_3$$

$$HCO^-_3 + OH^- \rightarrow CO_3^{--} + H_2O$$

Carbonation Reaction Process

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

$$CaO_{1.5}SiO_2 \cdot 2H_2O + 1.5\ CO_3^{--} \rightarrow$$
$$1.5\ CaCO_3 + 3\ OH^- + SiO_2 + 0.5H_2O$$

Carbonation Reaction Process

The binder is completely destroyed.

Why does carbonated concrete maintain or increase strength?

Factors Influencing Carbonation

- Porosity of Concrete
- Available Calcium Hydroxide
- Carbon Dioxide Concentration
- Relative Humidity
- Temperature

Water-Cement and Depth of Carbonation

W/C	Age (years)	Depth of Carbonation (mm)
0.45	136	5
0.70	10	50

Water-Cement Ratio

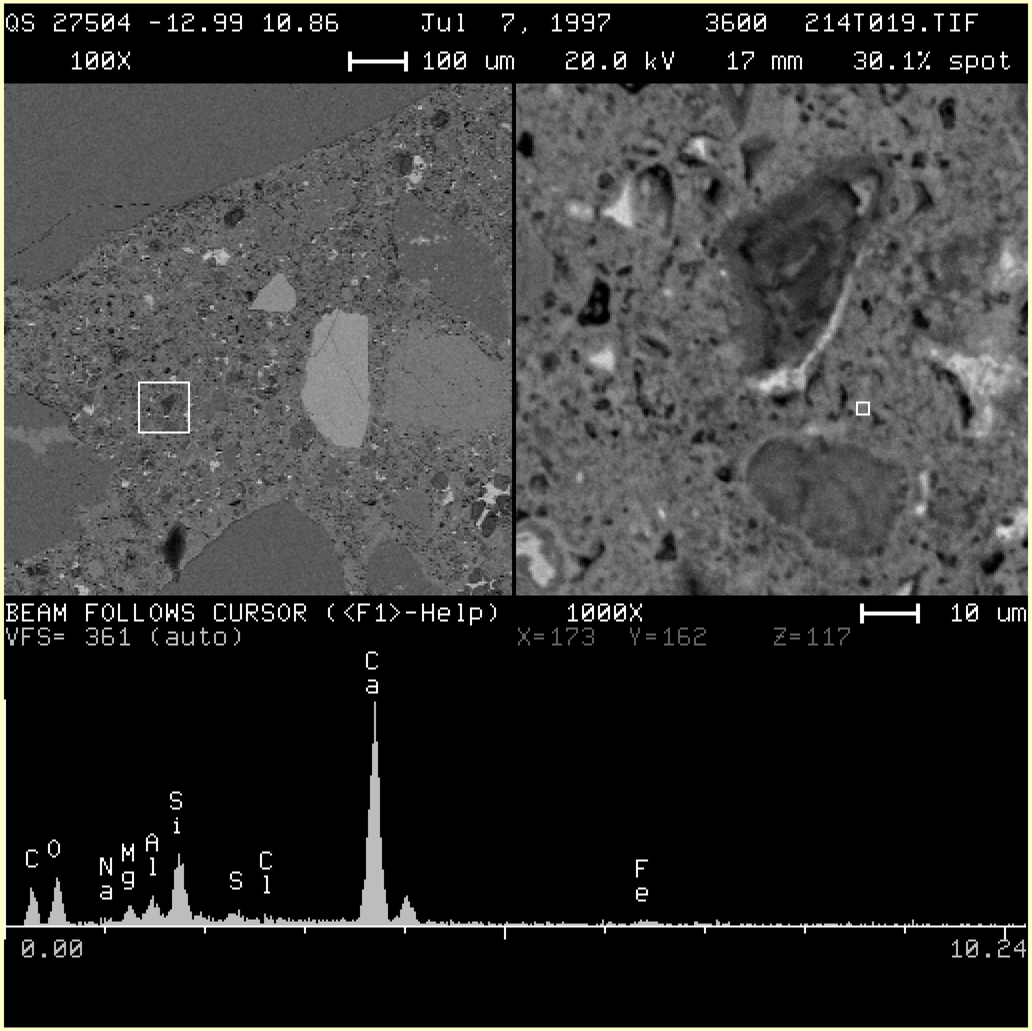
- The W/C determines the porosity and permeability of the concrete.
- Much of the water in concrete does not react with the cement.
- The excess water creates capillary porosity in the concrete.

Water-Cement Ratio

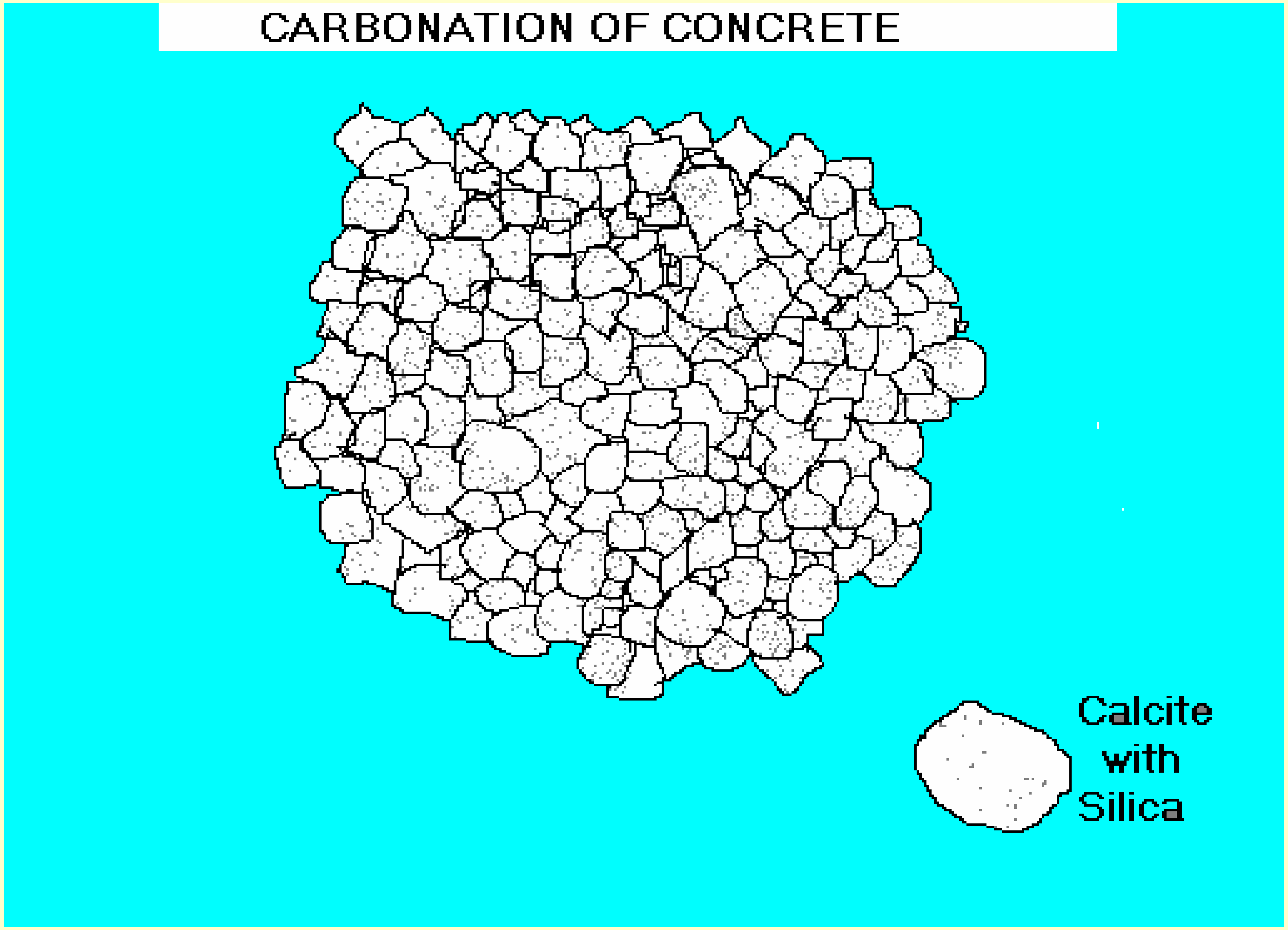
W/C	% Capillary Porosity
0.40	8
0.45	14
0.50	19
0.55	24
0.60	28
0.65	32
0.70	35

Relationship Between Water-Cement Ratio and Porosity of Cement Paste

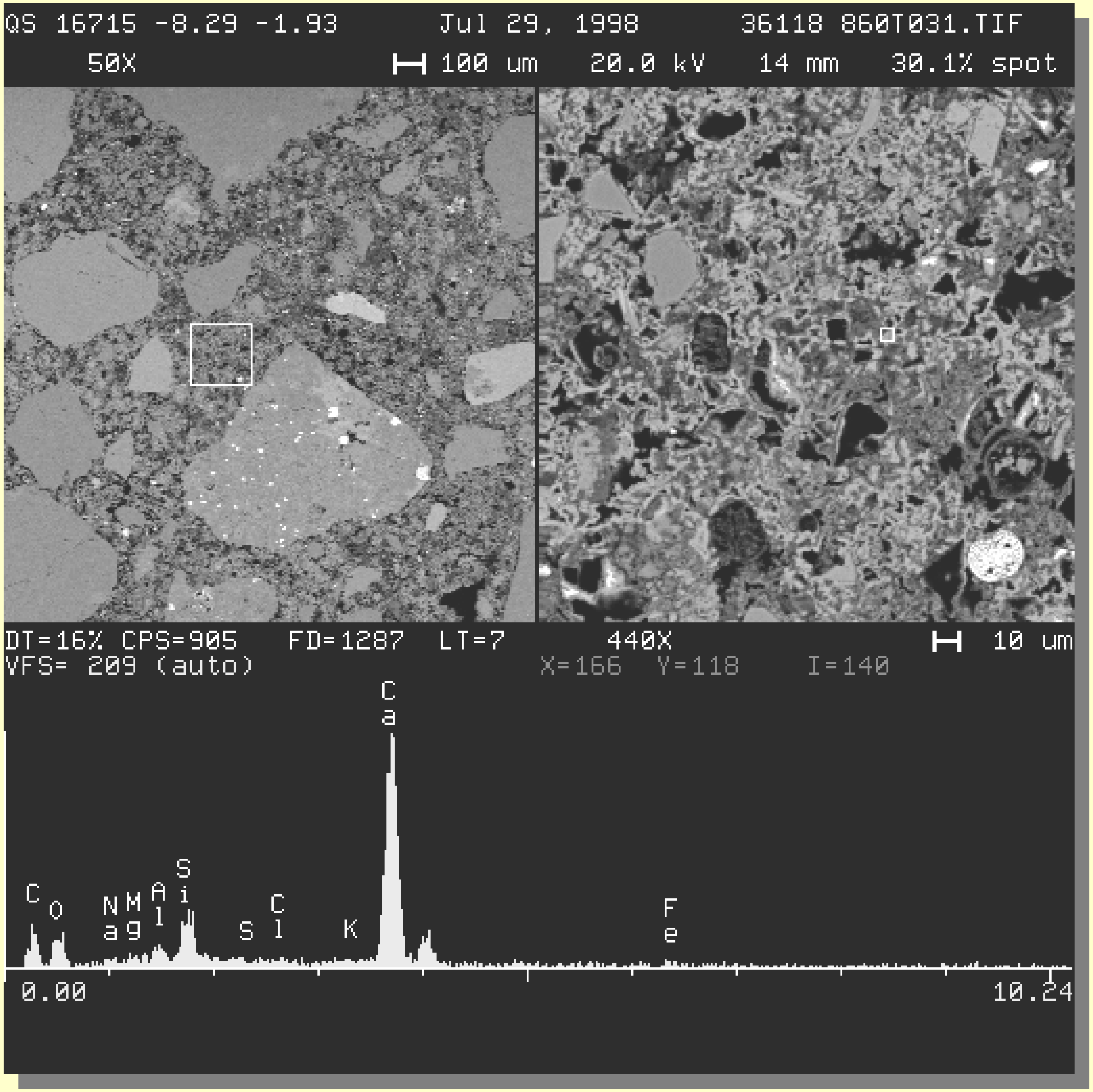
Dense Carbonation



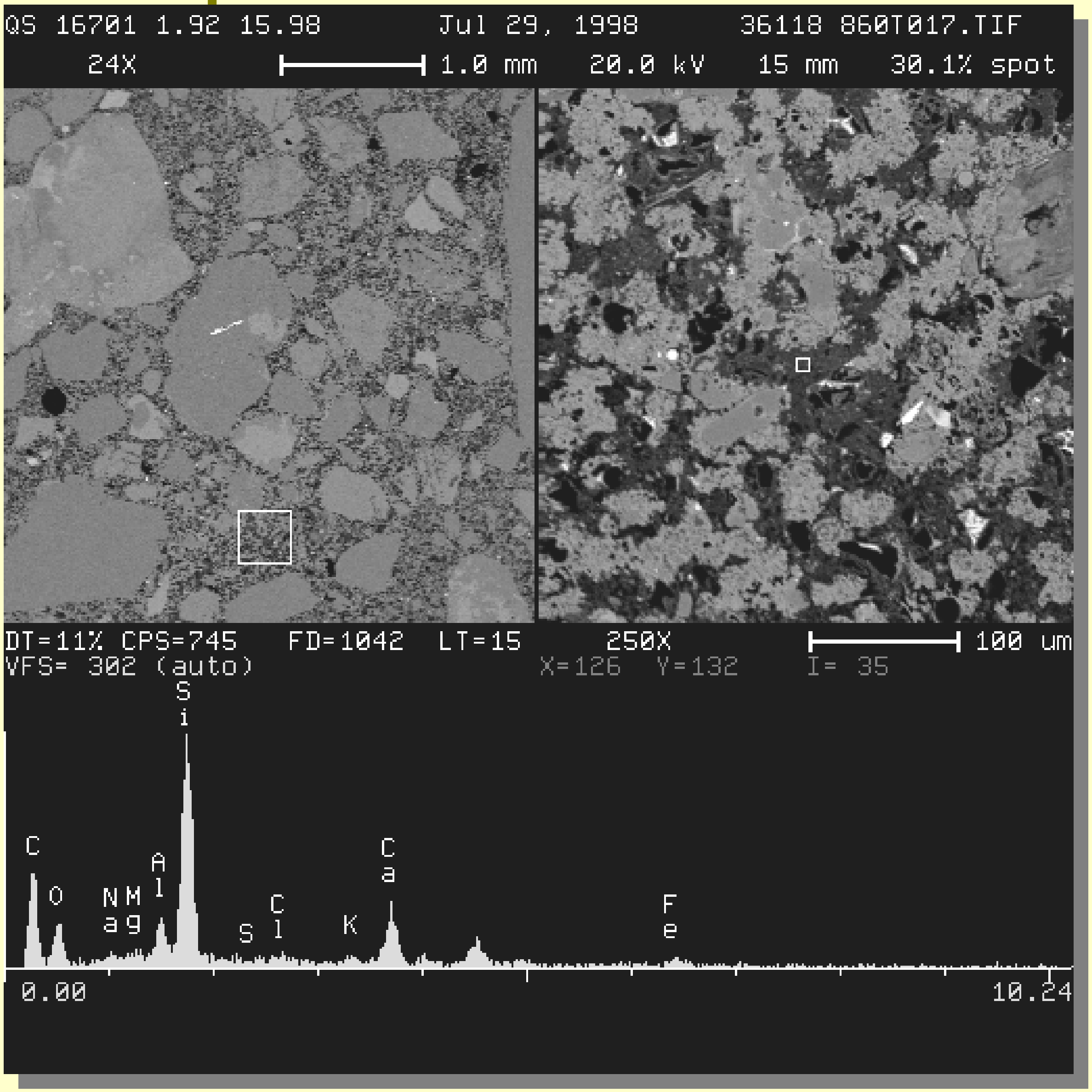
Carbonation



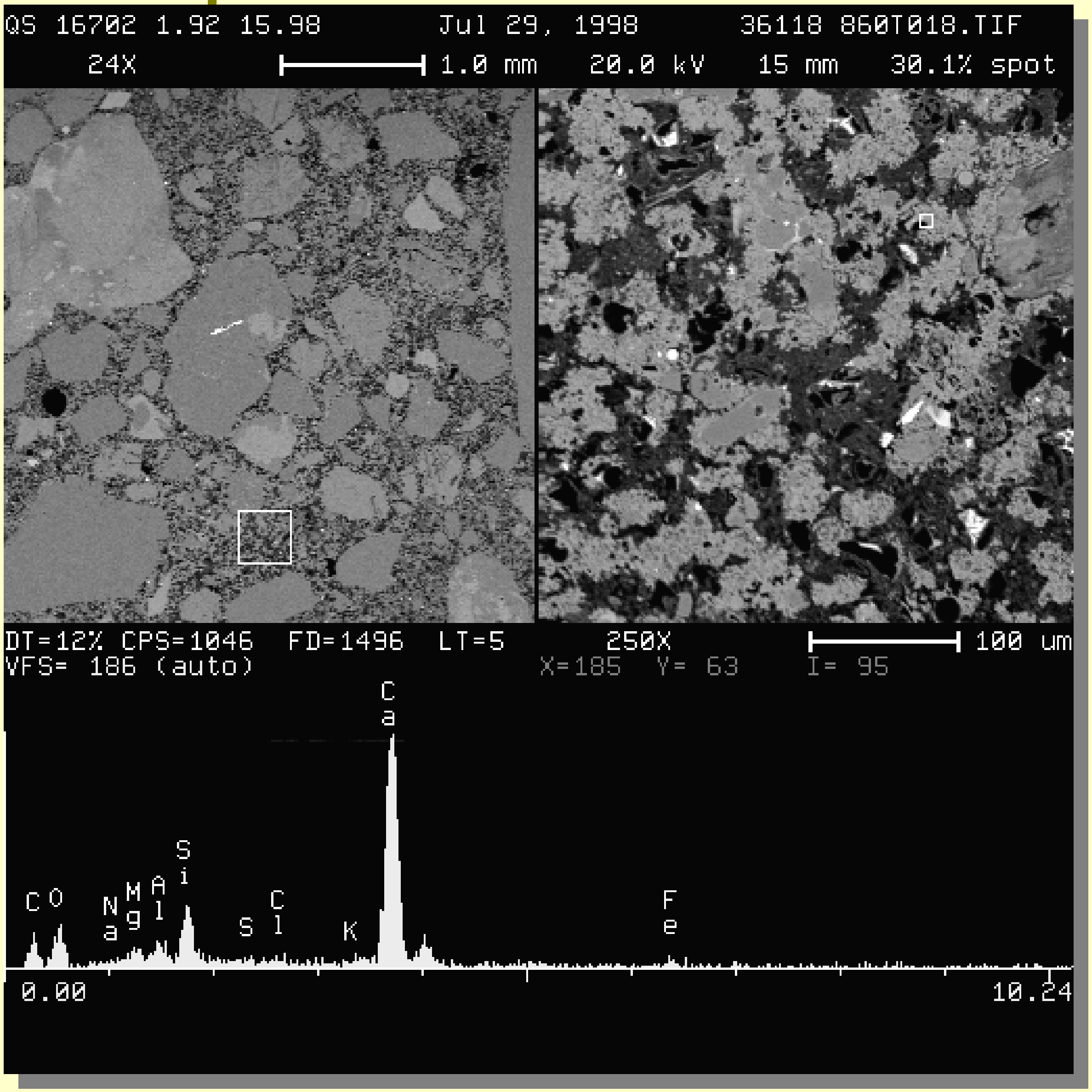
Intermediate Carbonation



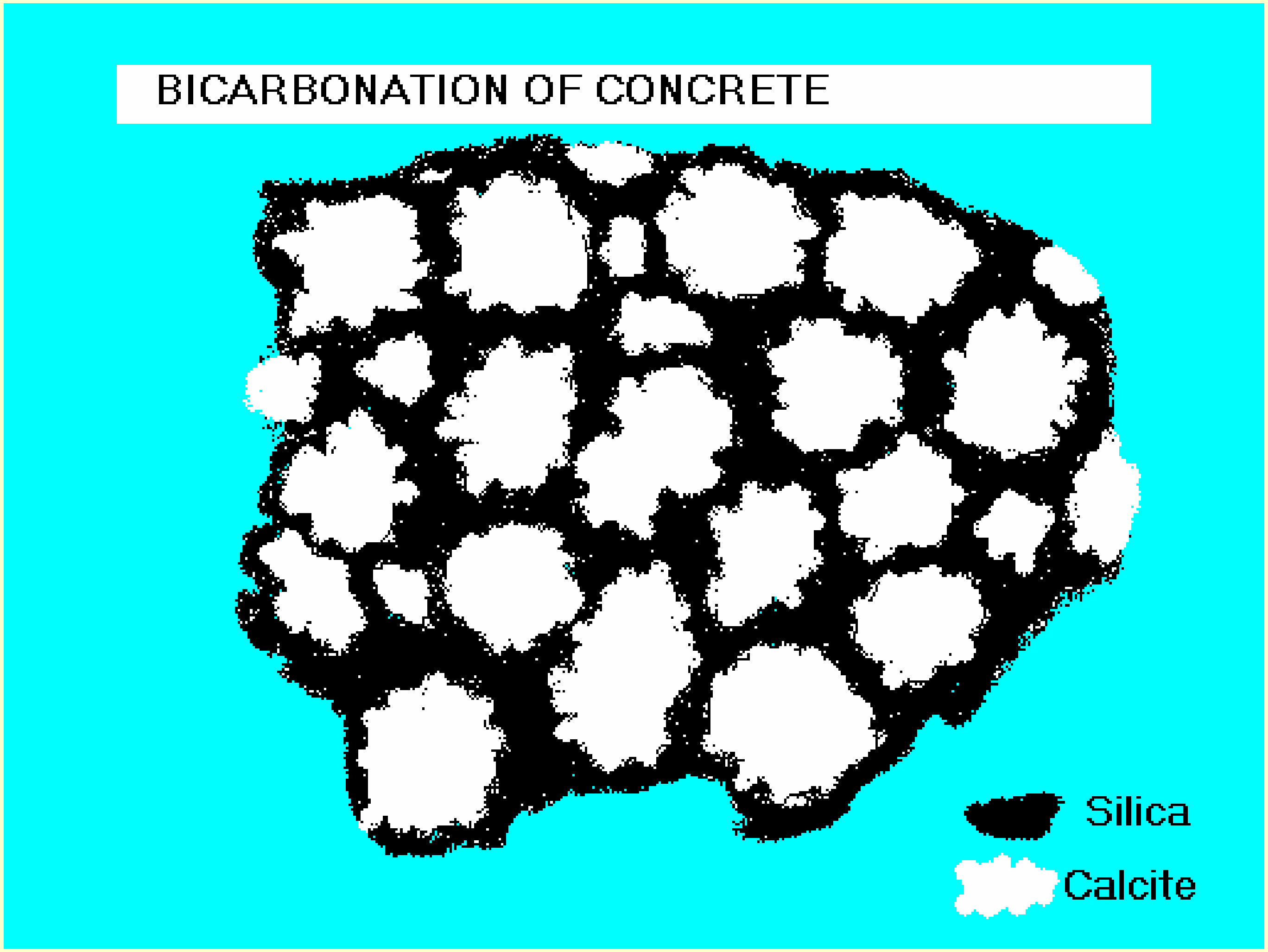
“Popcorn” Carbonation



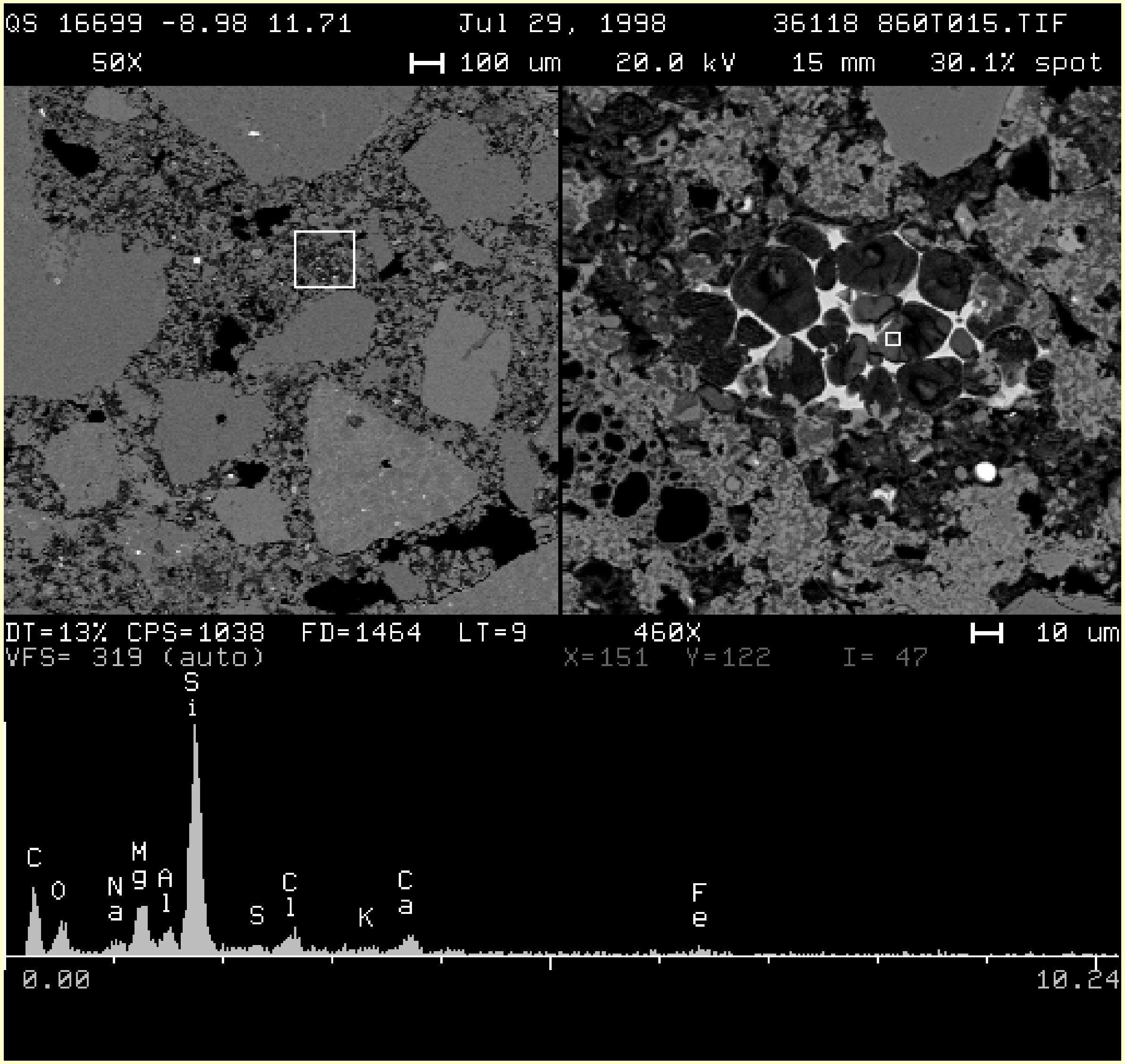
"Popcorn" Carbonation



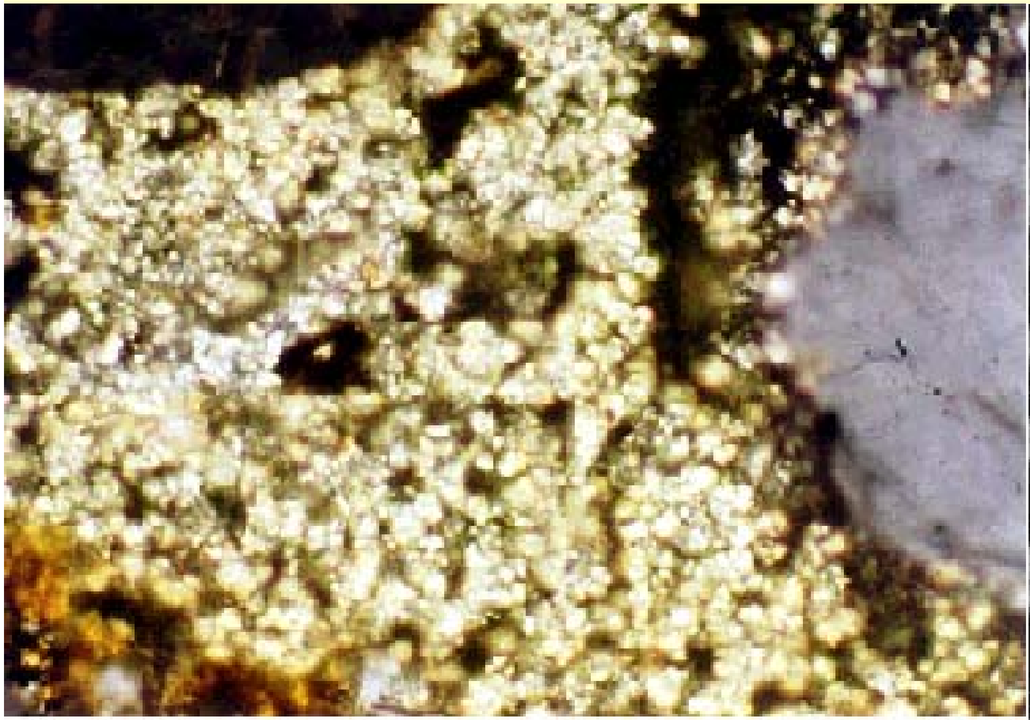
“Popcorn” Carbonation or Bicarbonation

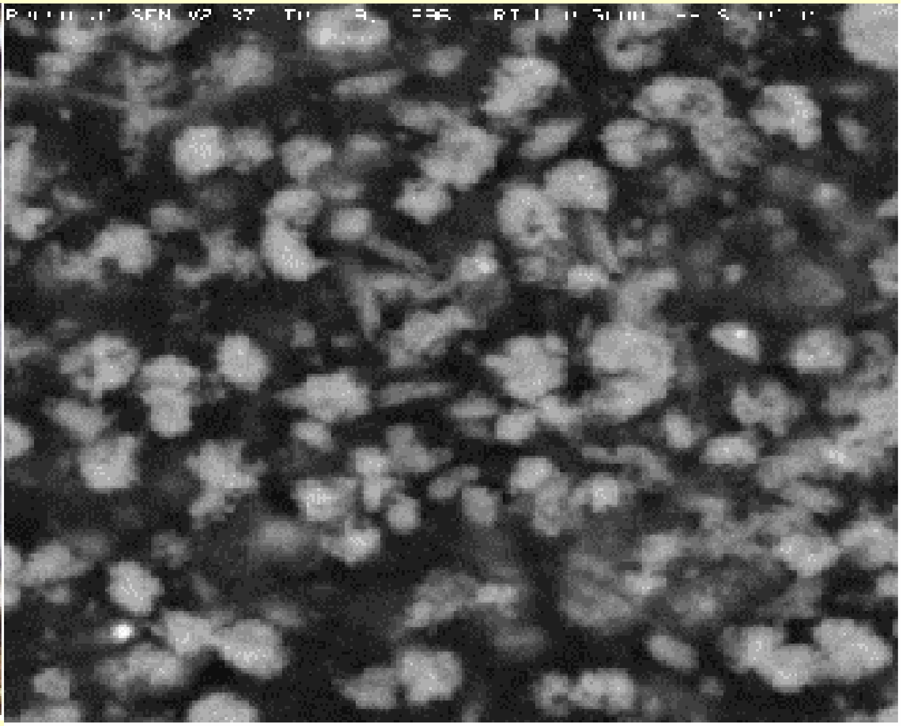


Deleterious Carbonation



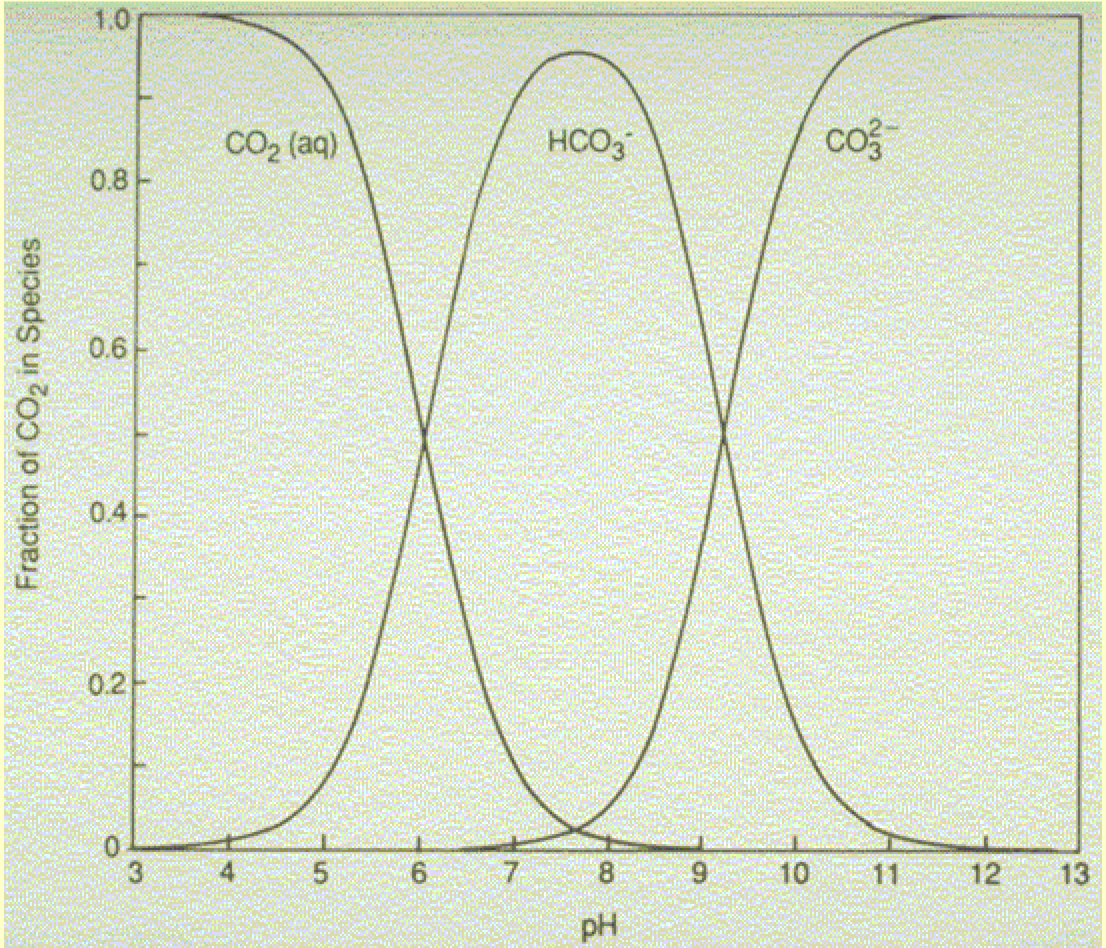
Carbonated “Popcorn” Paste





Pop Corn

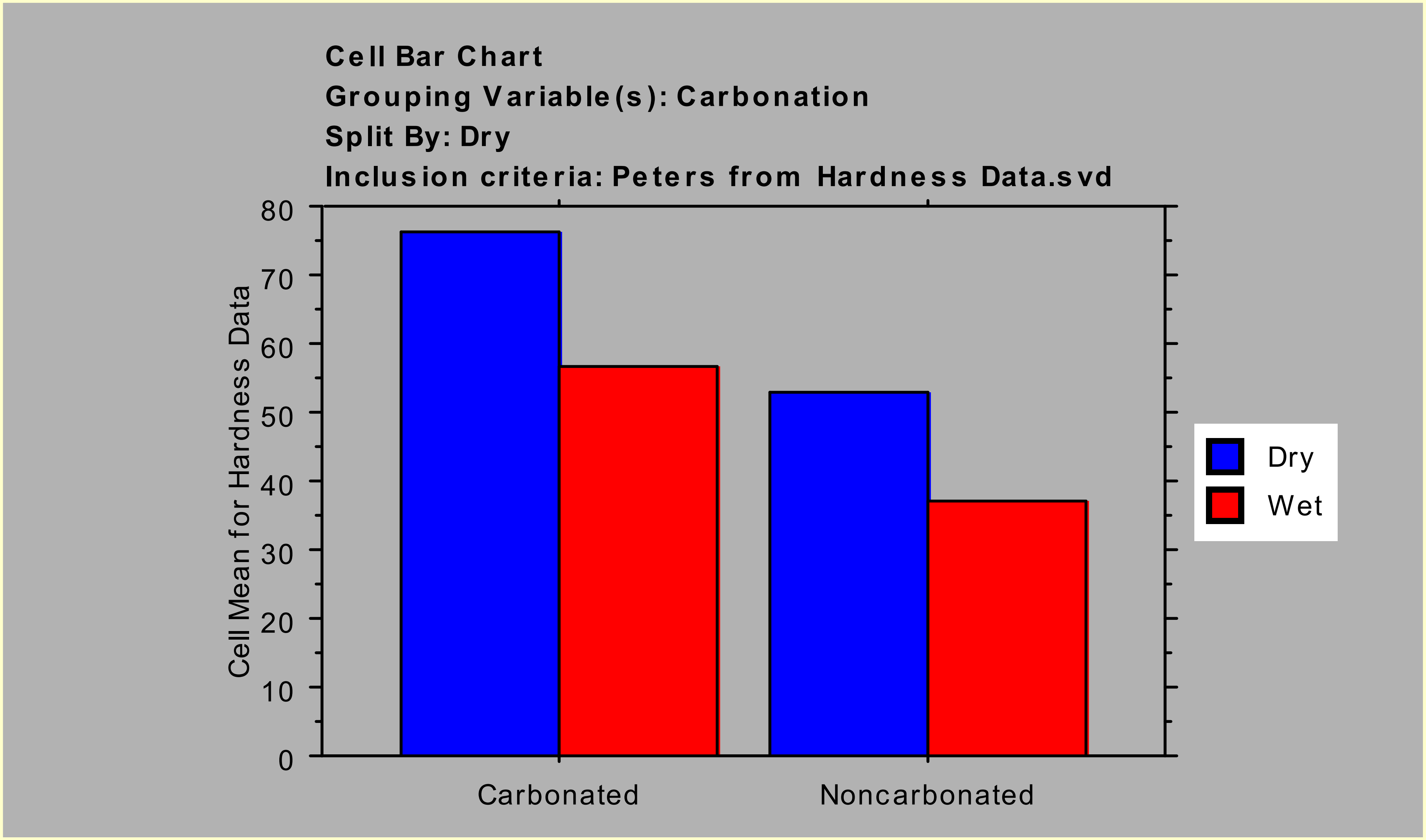
Stability of Carbonate Species



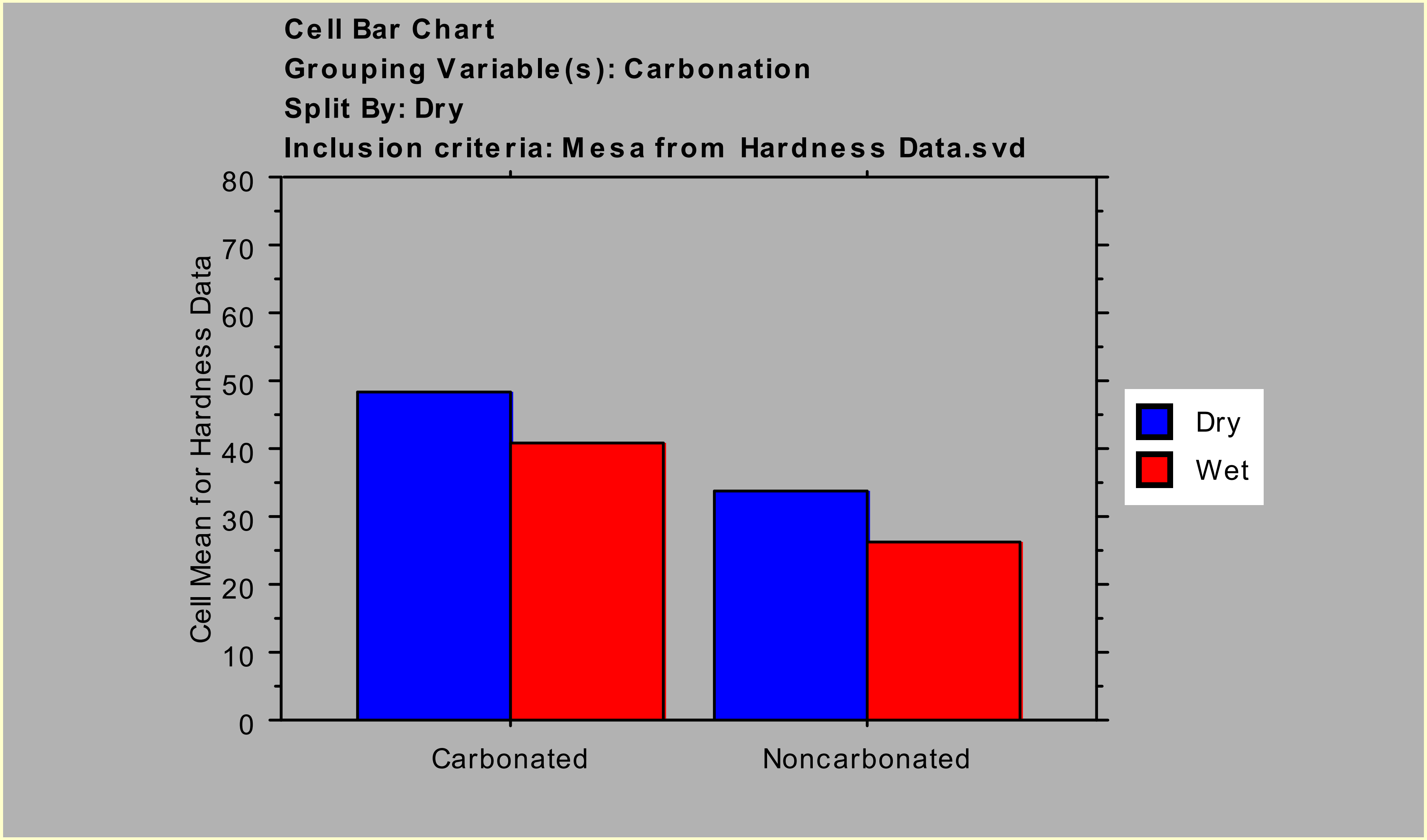
Influence on Concrete Properties

- Microhardness
- Tensile Strength
- Compressive Strength
- Permeability
- Freeze/Thaw Resistance

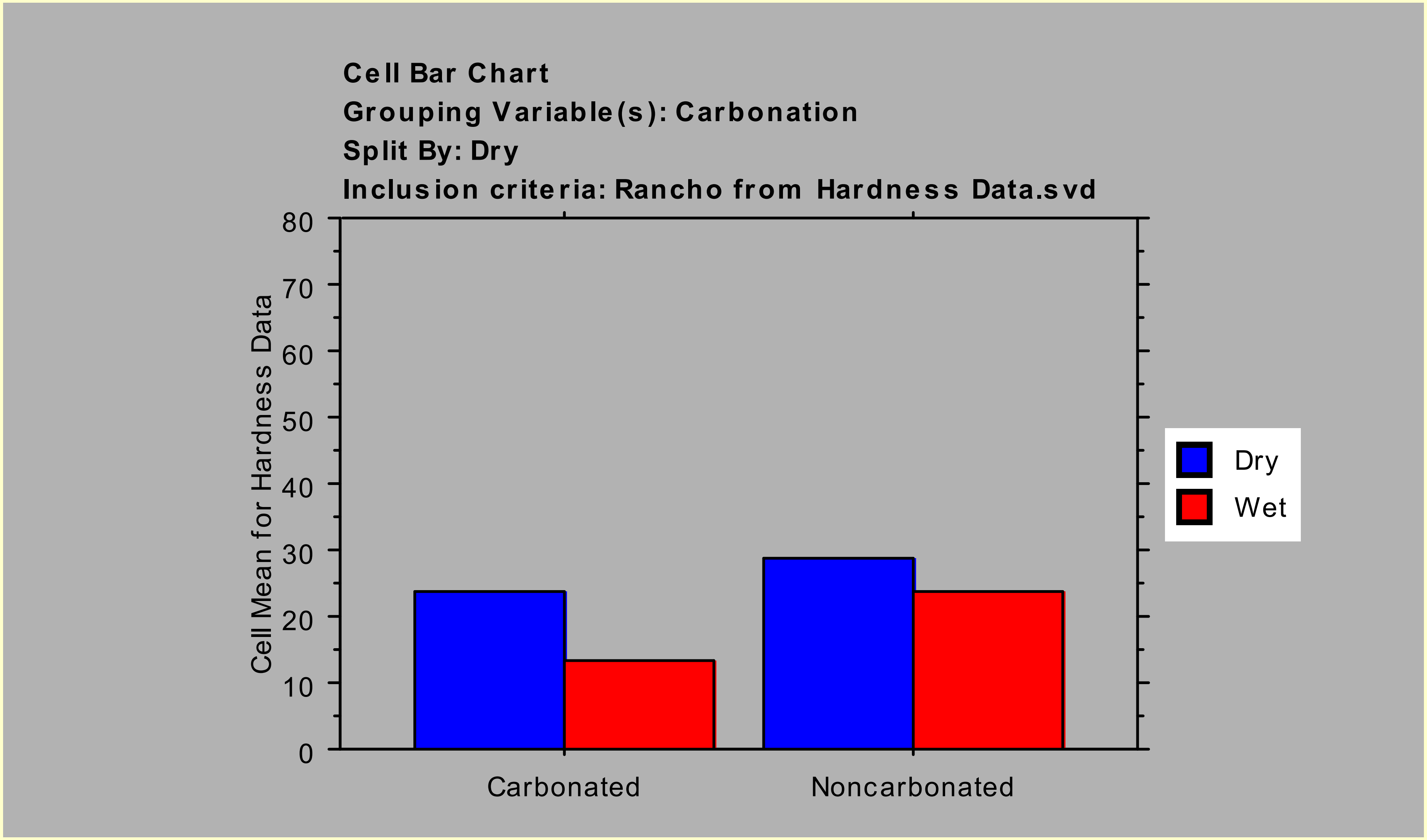
Hardness Data



Hardness Data



Hardness Data



Practical Consequences

- W/Cm
- Cement Content
- Degree of Hydration
- Pozzolans
- Environment

Behaviour of Portland cement in CO_2-rich water/brine. Implications on wellbore integrity for CO_2 storage.

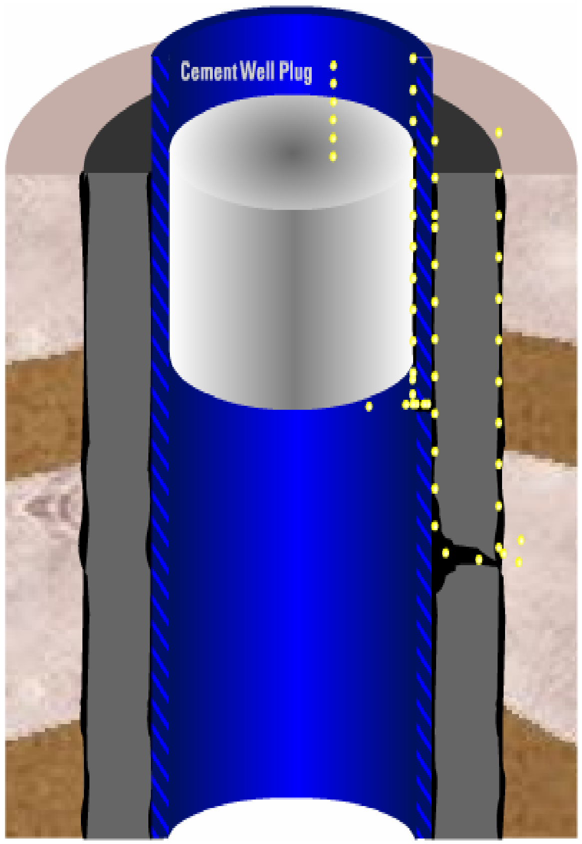
V.Barlet-Gouédard, G.Rimmelé, O.Porcherie, Schlumberger

3rd Well Bore Integrity Network Meeting
12–13 March 2007, Santa Fe

Schlumberger

Motivation and Approach

- CO_2 leakage, one major risk for CO_2 storage underground
  - ➢ Long-term cement zonal isolation
- Wells in oil & gas depleted fields
  - ➢ Portland cement
- Develop a standard CO_2-testing procedure
  - ➢ Salinity and temperature effect on the Portland degradation



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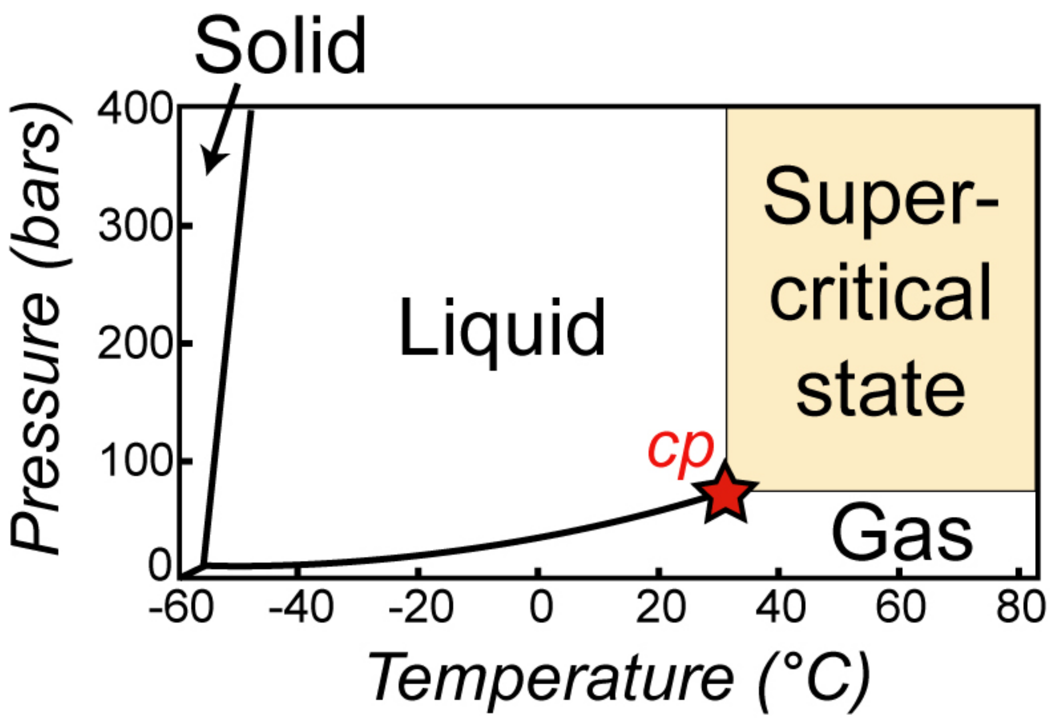
Storing supercritical CO_2 underground

- Supercritical fluid: viscosity of a gas, density of a liquid, high diffusivity
- *cp* (critical point) for CO_2: T=31.6°C and P=73 bars



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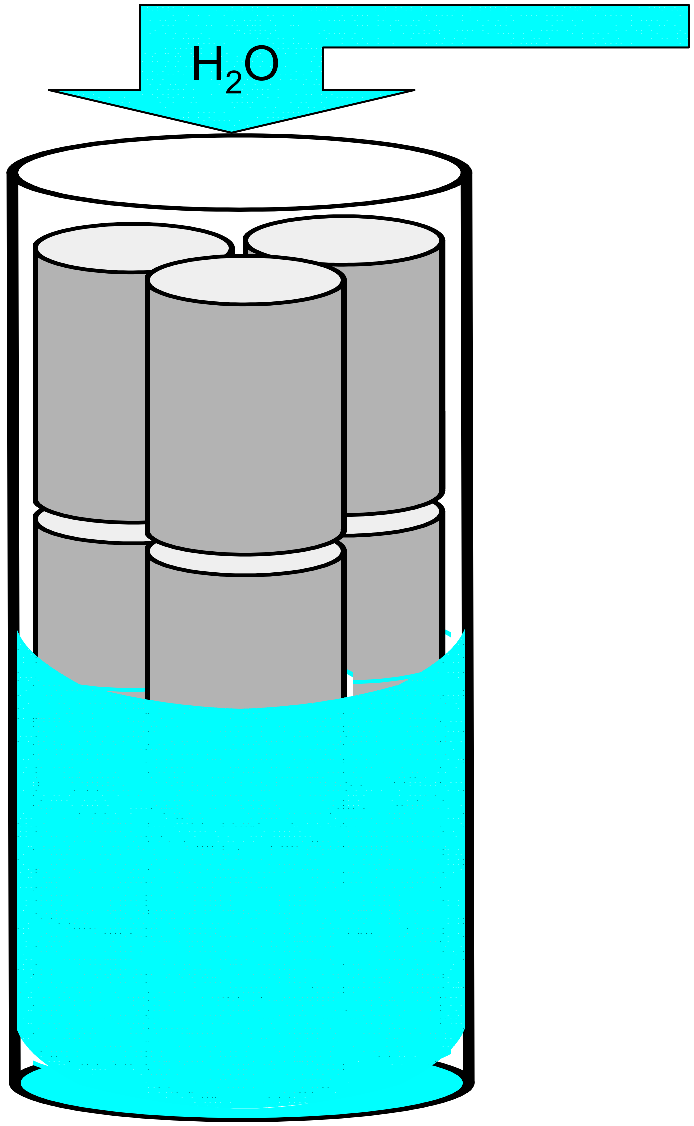
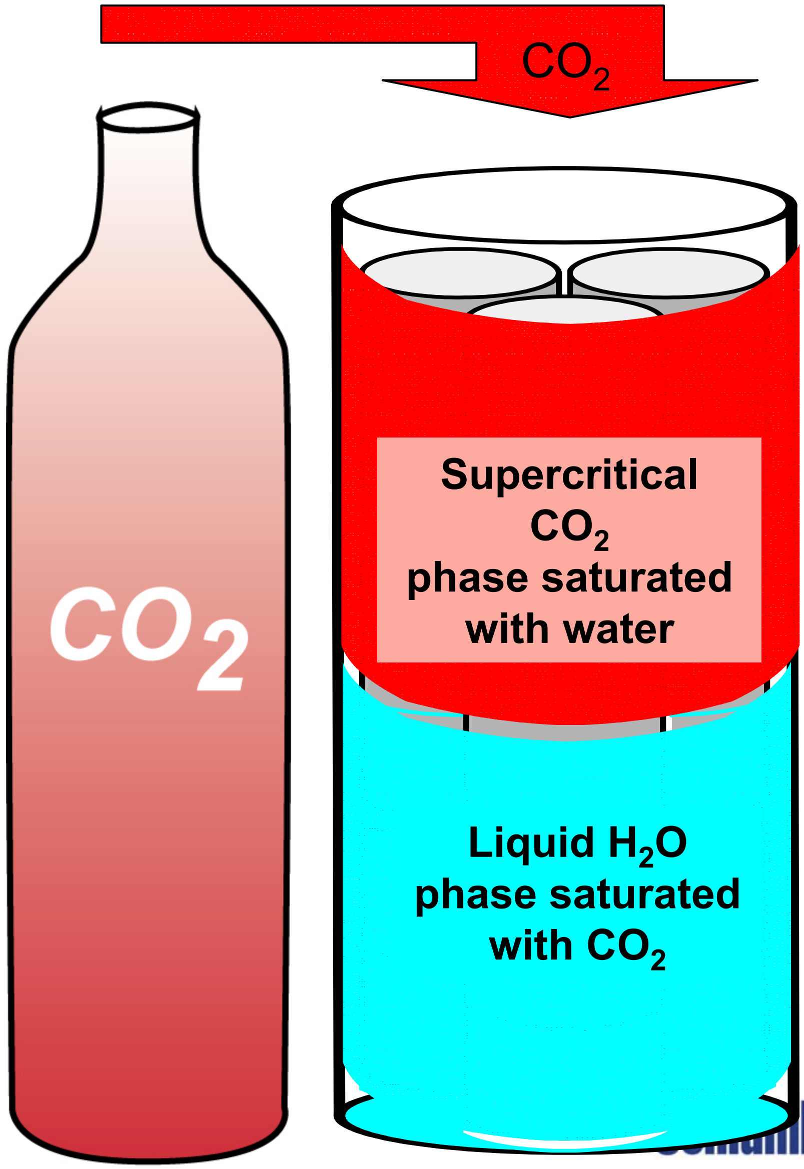
Experimental Apparatus

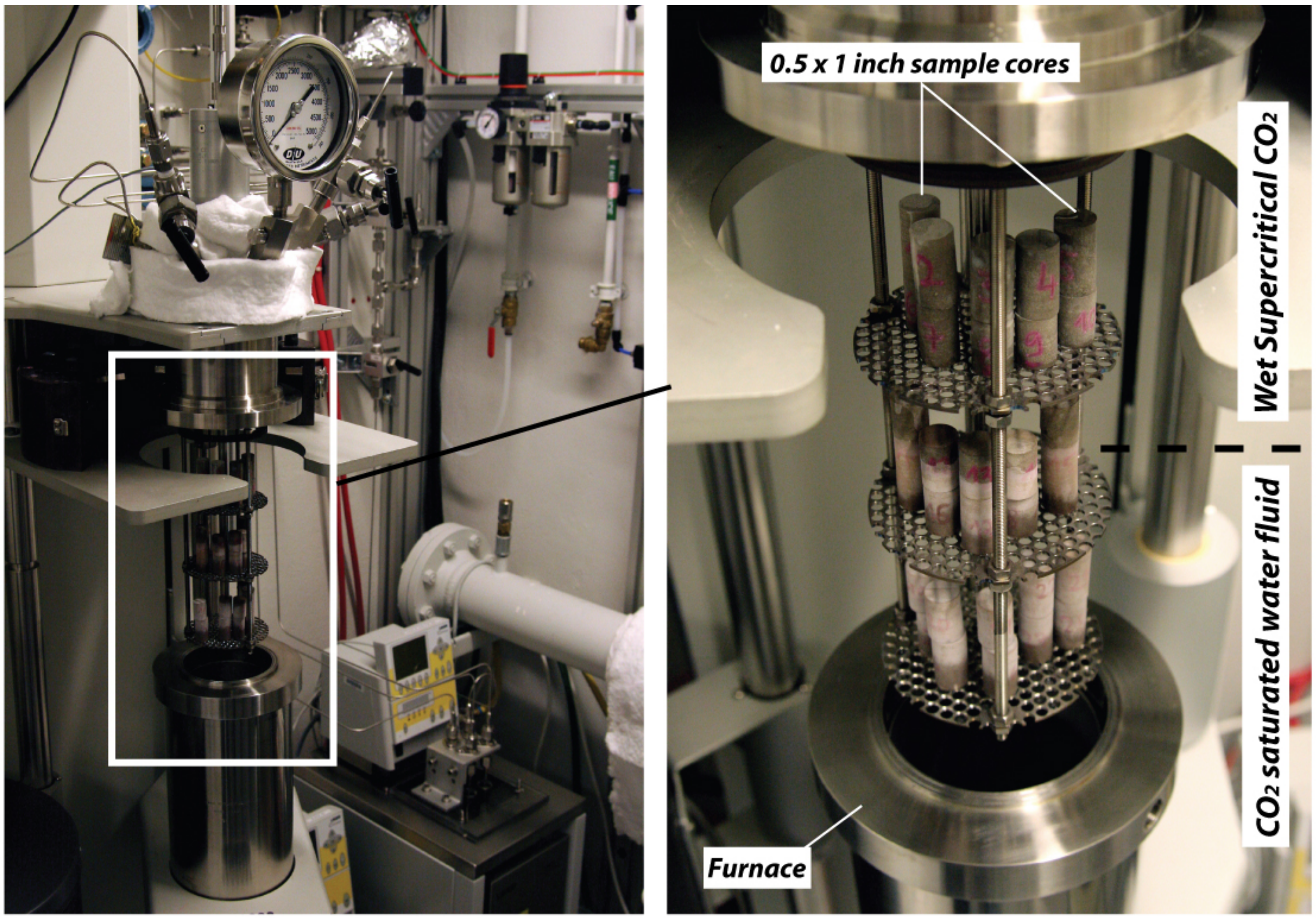


Experimental Apparatus

- Diphasic system



A new equipment for CO_2 tests



TEST CONDITIONS:
P=280 bars
T=90°C, 40 °C

Pmax = 350 bars/ Tmax = 500°C

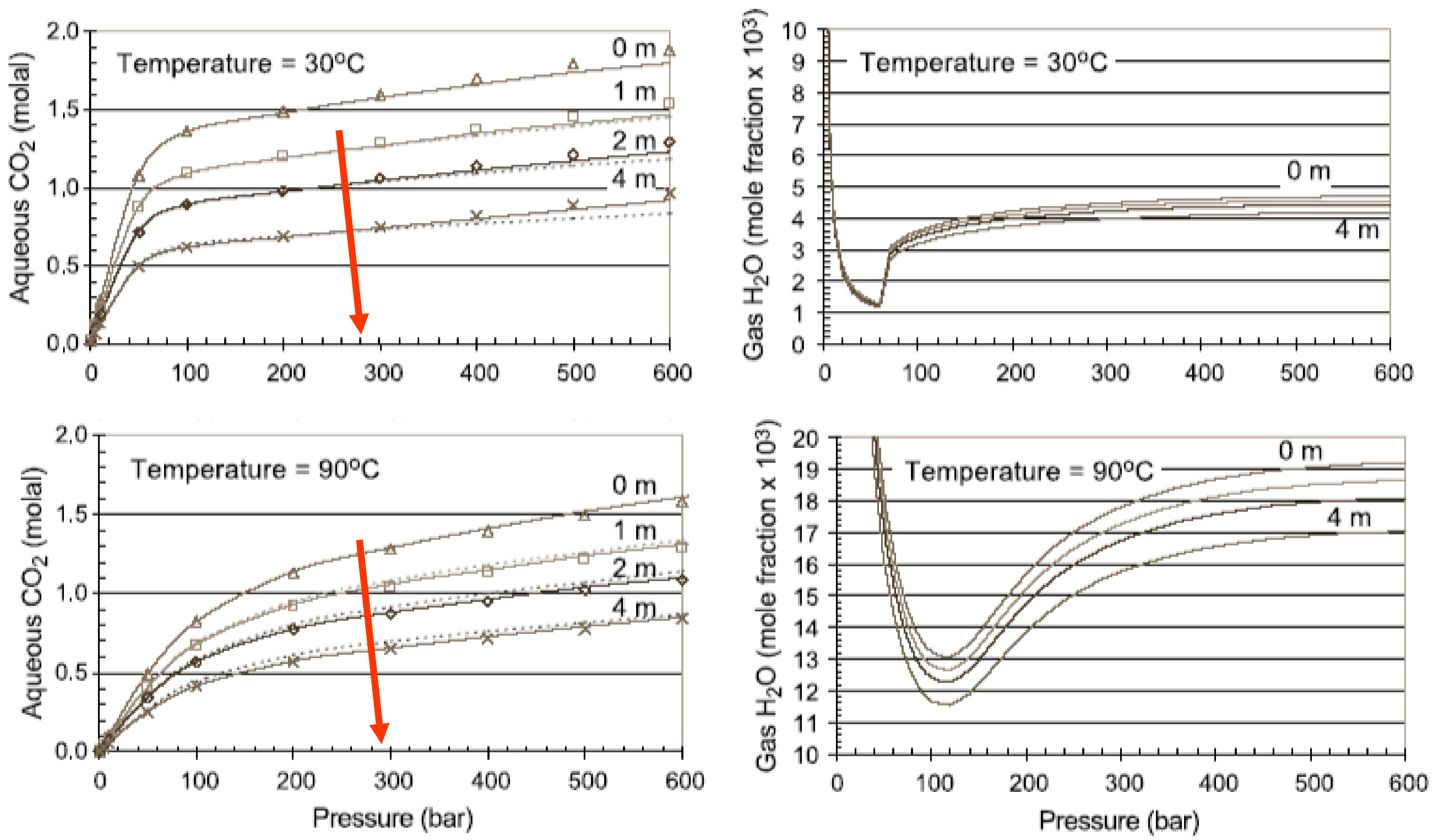
Evolution of the alteration of Portland cement

- With salinity at 90deg.C under 280 bars
  - → in water
  - → in 4 m NaCl brine

- With temperature in 4 m NaCl brine under 280 bars
  - → 40 ^{o}C
  - → 90 ^{o}C

Effect of the fluid on Portland cement alteration

CO_2+water vs CO_2+brine (218 g/L- 4 m NaCl)



(Spycher and Pruess, 2005)

CO_2 saturation ↘ with salinity ↗

Effect of the fluid on Portland cement alteration

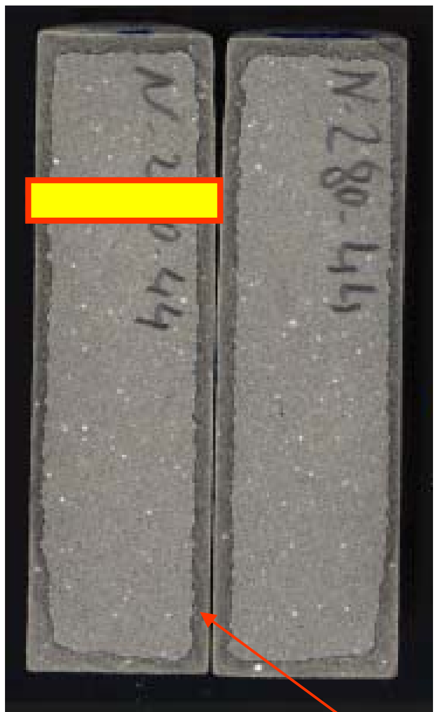
CO_2 exposure: 2 days, 280 bars, 90ºC

Water

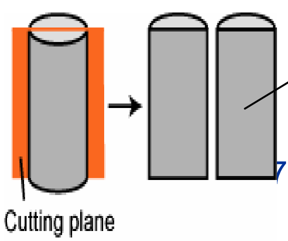
4 m NaCl Brine

Wet super-critical CO_2

CO_2 – saturated fluid



Alteration front



Front ~2 mm

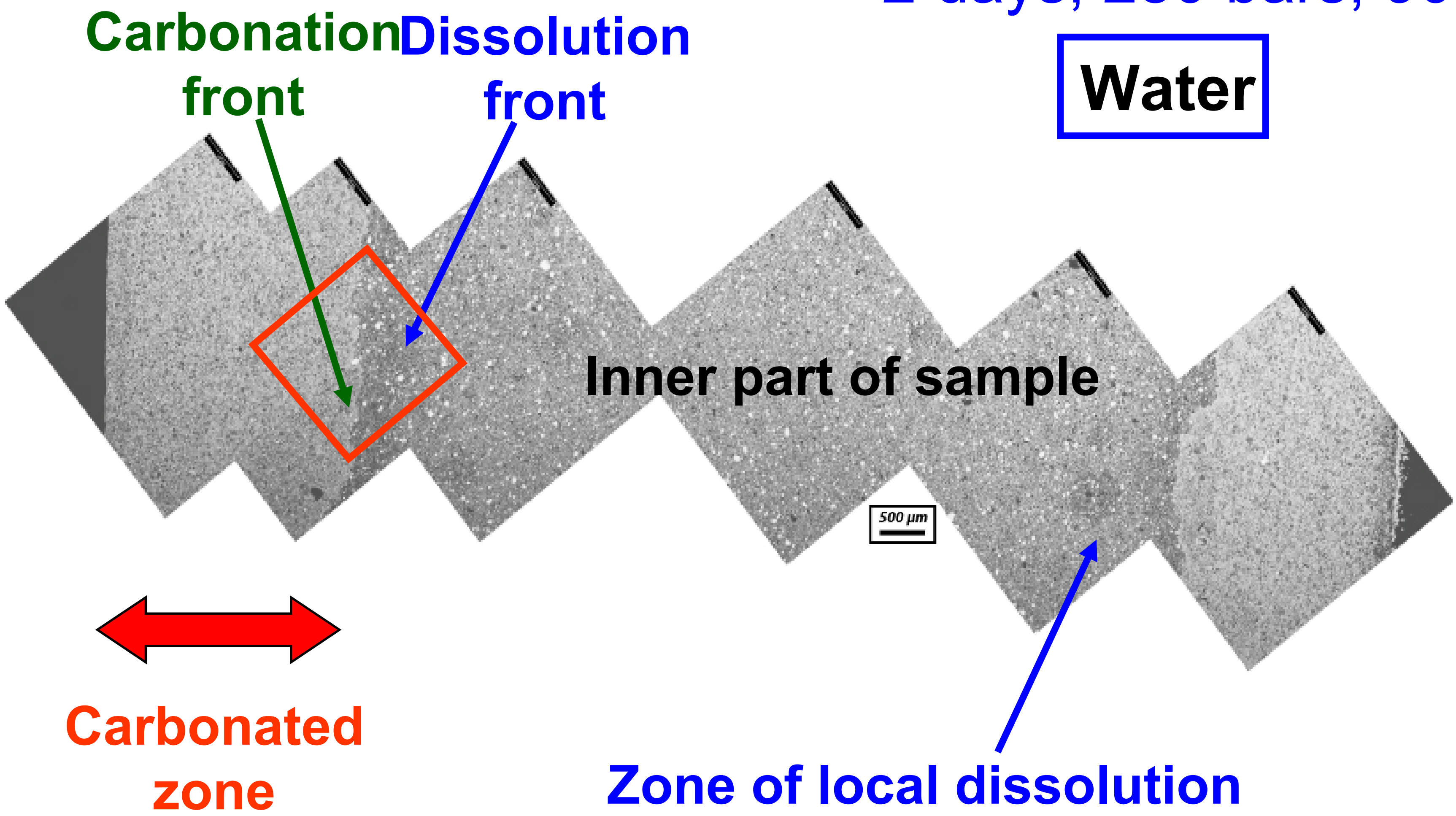
x 10

Front ~200 μm

Schlumberger

Effect of the fluid on Portland cement alteration

2 days, 280 bars, 90ºC

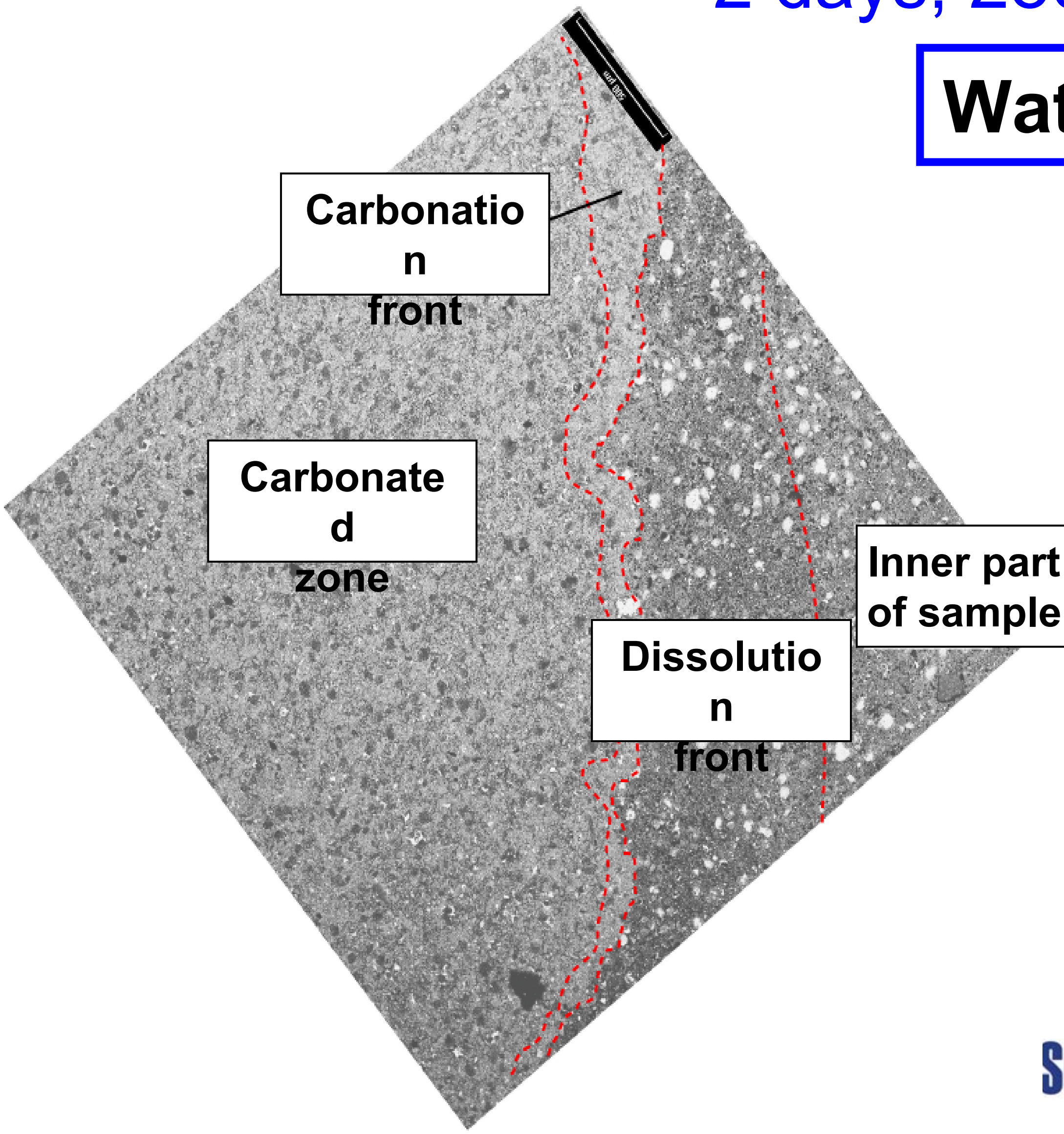


Schlumberger

Effect of the fluid on Portland cement alteration

2 days, 280 bars, 90ºC

Water



Schlumberger

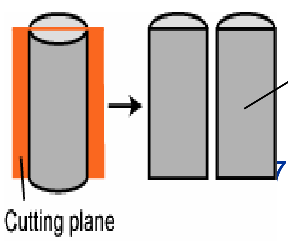
Effect of the fluid on Portland cement alteration

CO_2 exposure: 2 days, 280 bars, 90ºC

Water | **4 m NaCl Brine**

Wet super-critical CO_2

CO_2 – saturated fluid



Alteration front

Front ~2 mm

x 10

Front ~200 μm

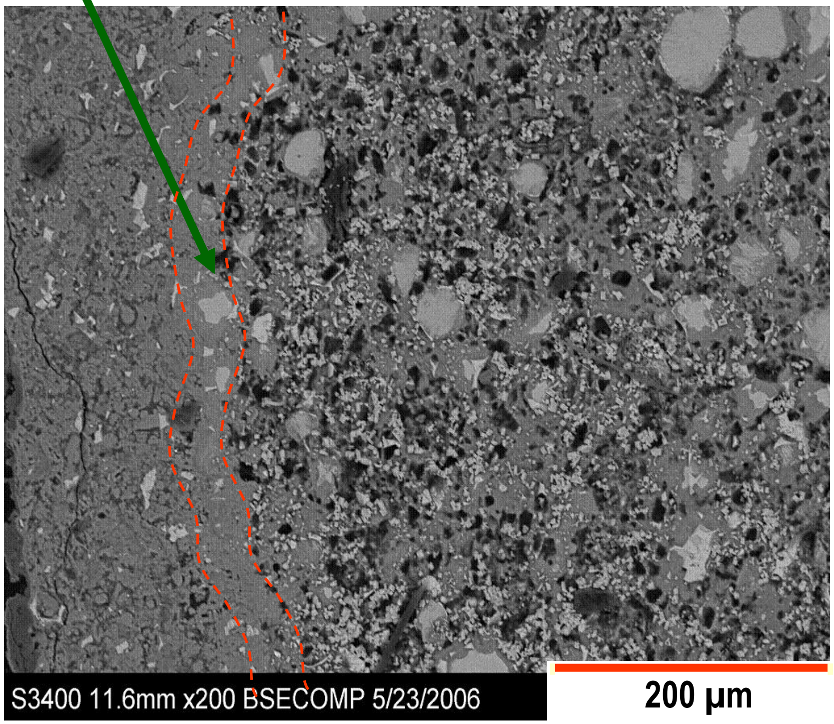
Schlumberger

Effect of the fluid on Portland cement alteration

2 days, 280 bars, 90ºC

Brine

Carbonation front



Inner part of sample

Rim of sample

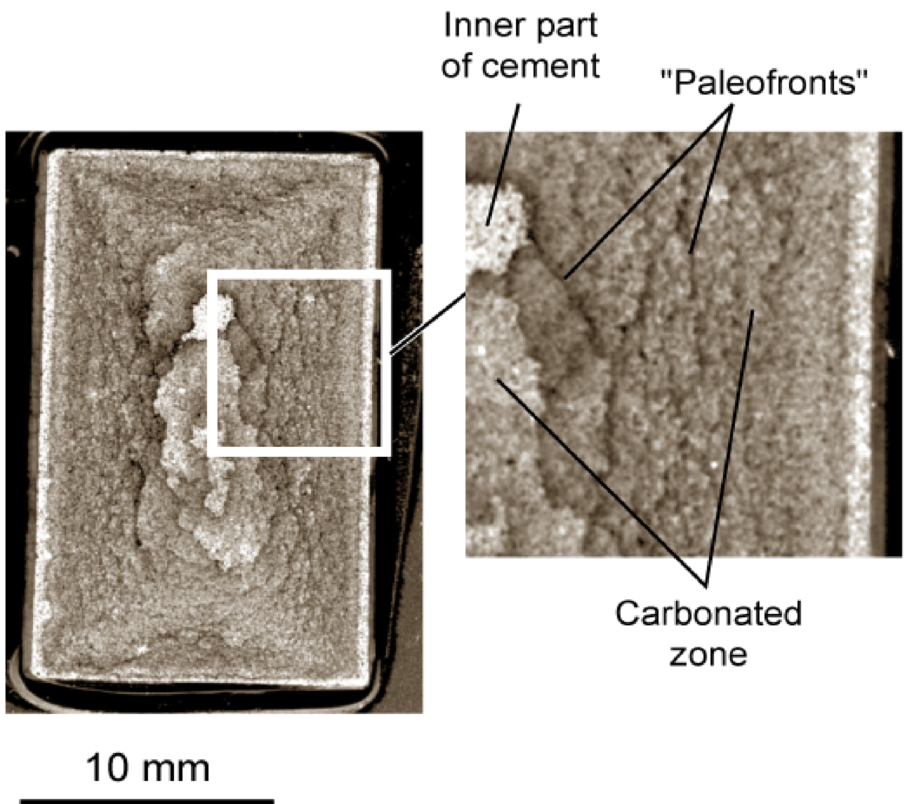
Schlumberger

CO_2 testing in water: Accelerating effect

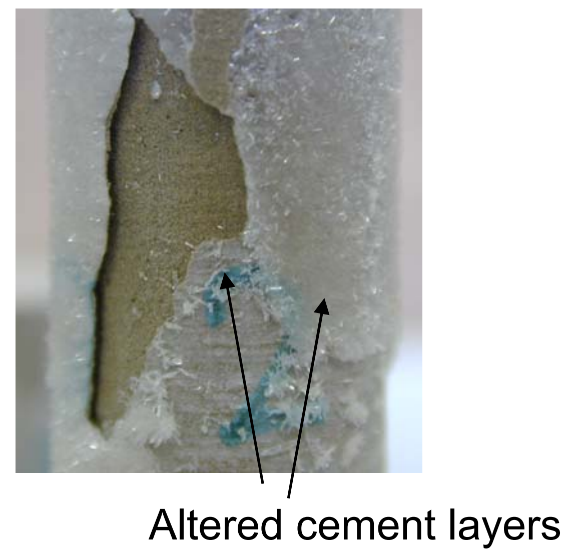
280 bars, 90ºC, water

Succession of carbonation front, dissolution front, paleo-fronts

After 3 weeks in CO_2-fluids



After 6 months in CO_2-fluids



Brine —X10→ Water

5 years in brine with CO_2

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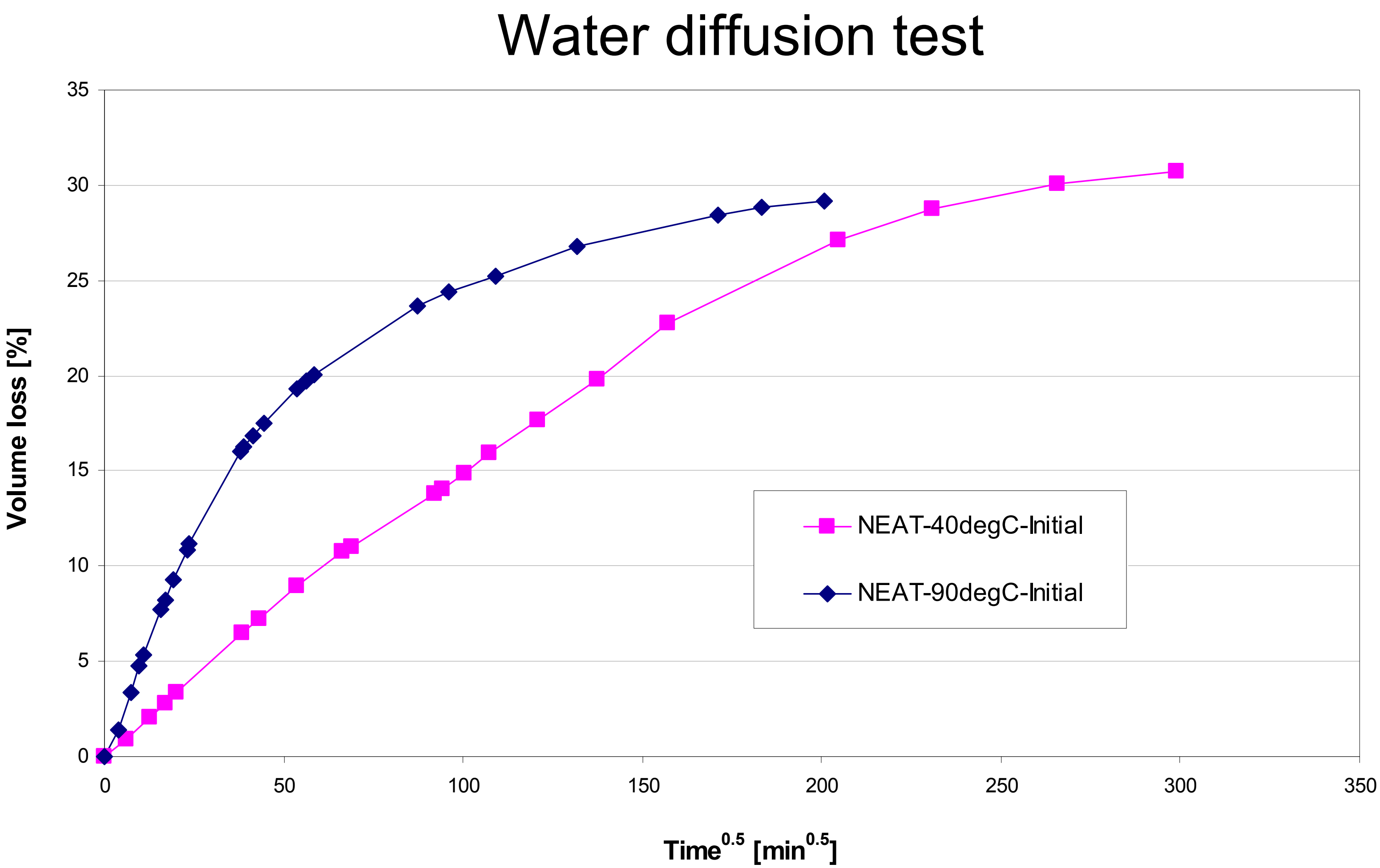
Effect of temperature on Portland cement alterat



→ Permeability increases with temperature (e.g. Mohd Zain et al., 1999)

Effect of <u>temperature</u> on Portland cement alterat

CO_2 exposure: 280 bars, 40ºC, Brine

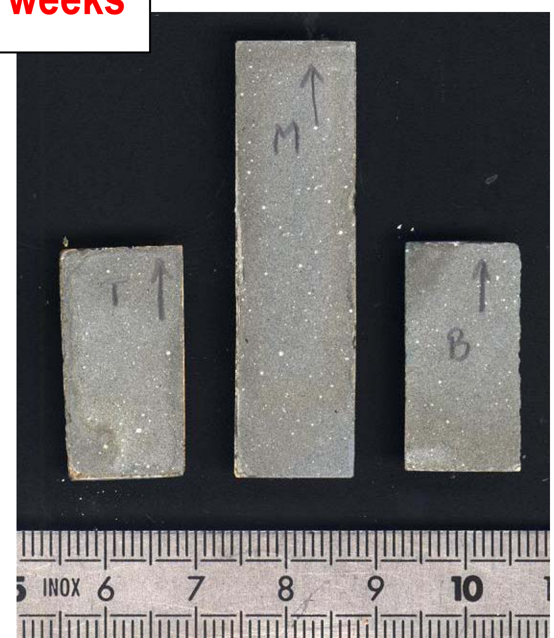
2 days

No visible front

1 week

No visible front

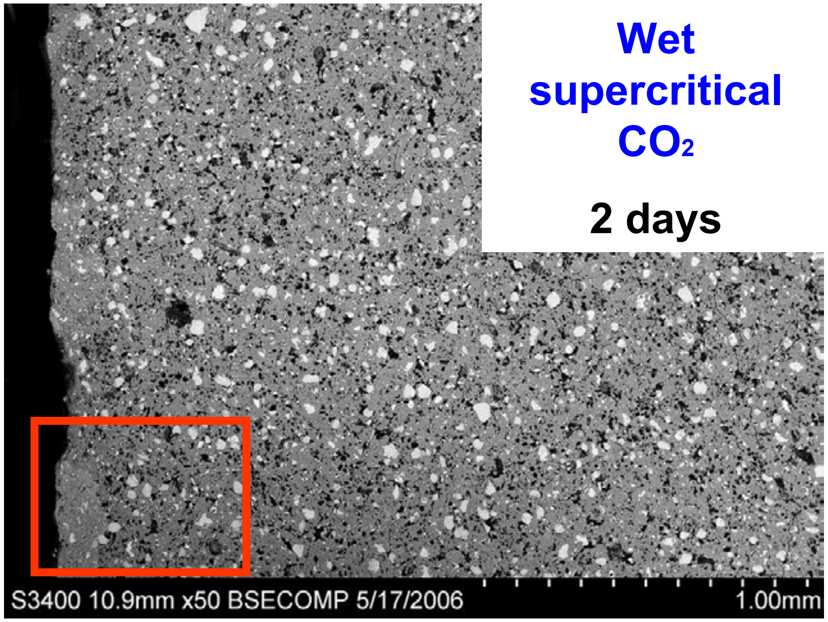
3 weeks

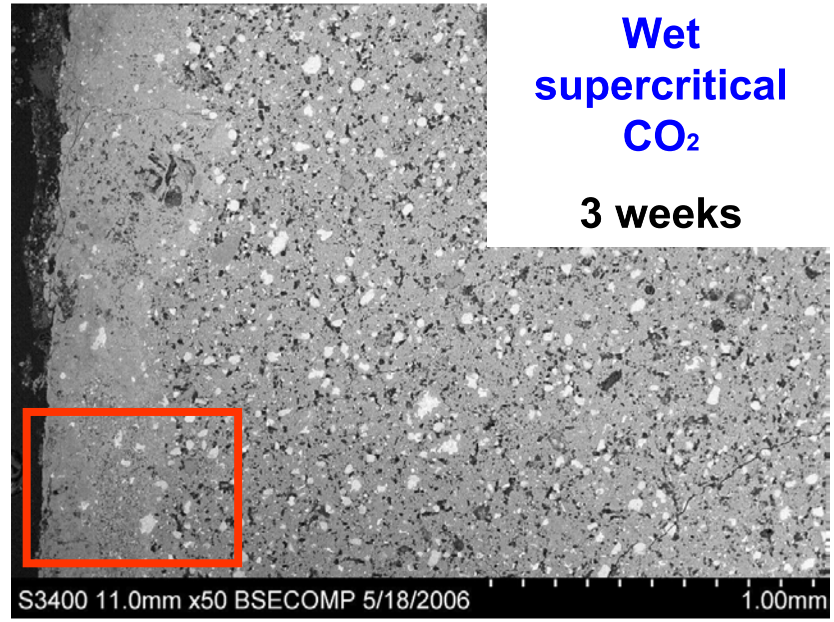


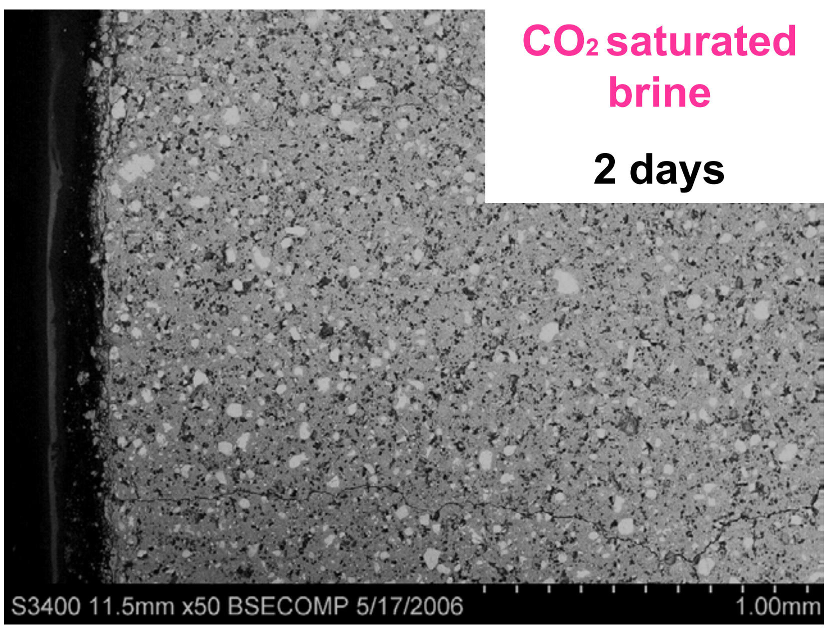
Very thin front

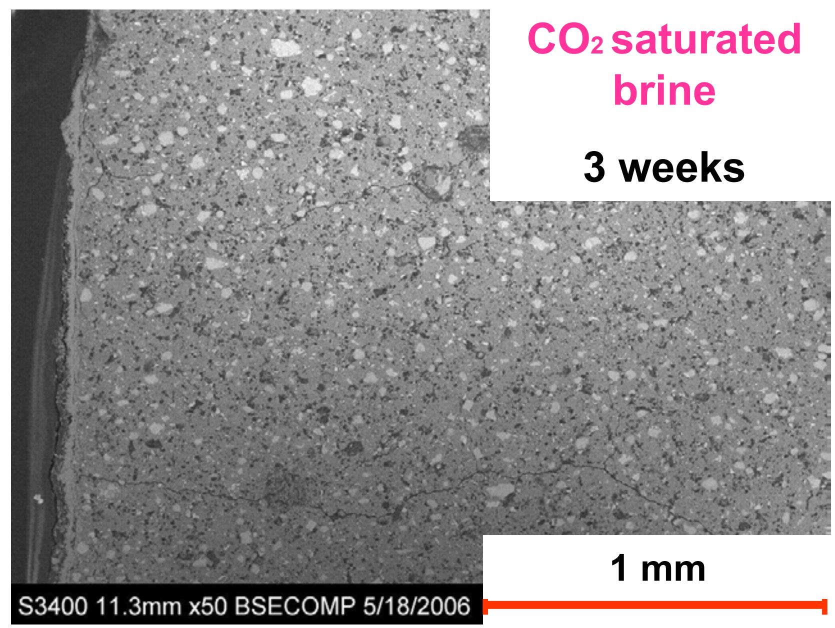
➡ **Scanning Electron Microscopy**

Effect of temperature on Portland cement alteration

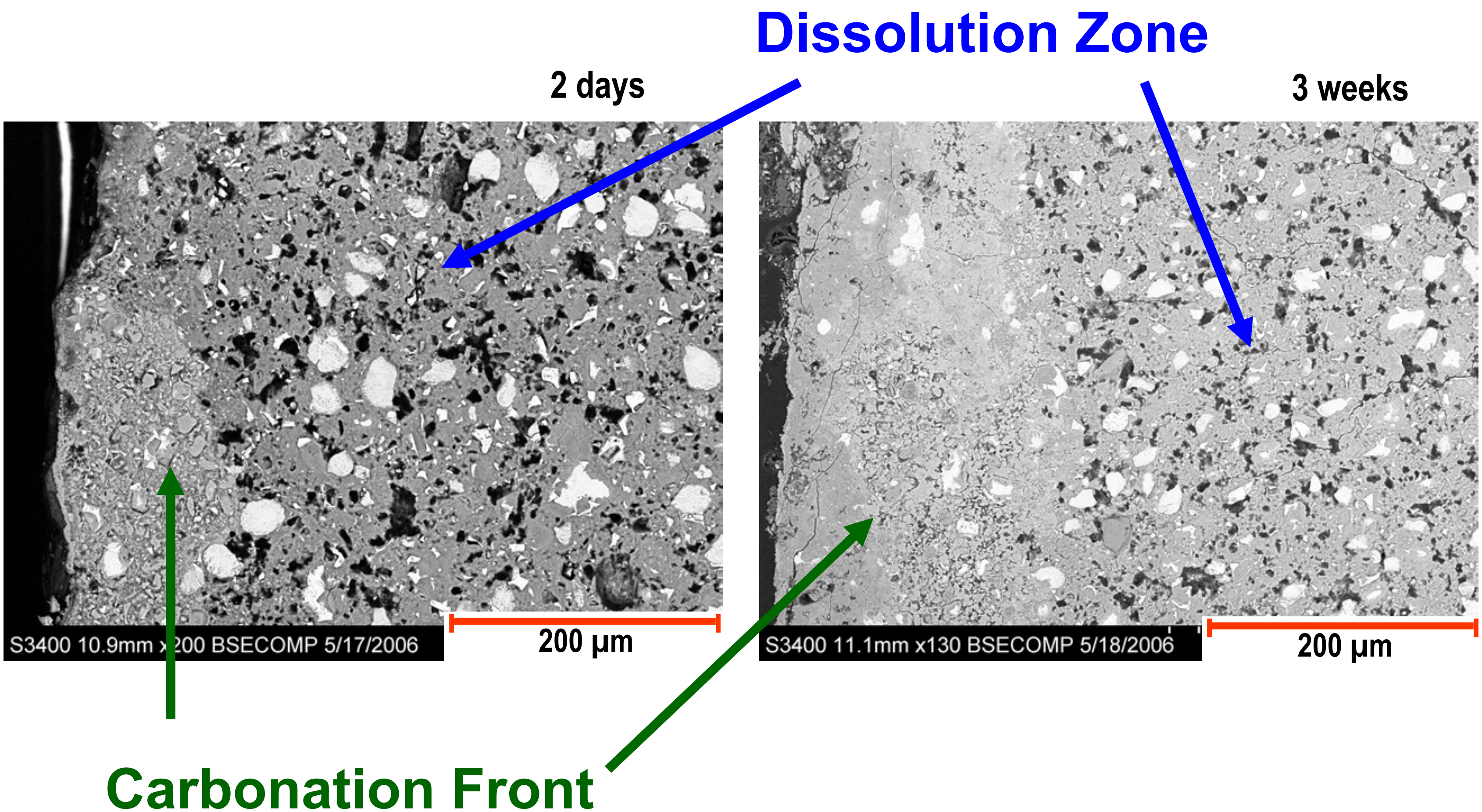








Effect of temperature on Portland cement alteration



CONCLUSION

- Faster kinetics at higher temperature and in water rather than in brine (x 10)
- Similar alteration mechanisms whatever conditions:

  → Portland cement: concentric series of dissolution/carbonation fronts, paleofronts, i.e. heterogeneous carbonation pattern

- Tests in water, at 280 bars and 90°C give the most severe conditions.

In some way, they “accelerate“ the alteration process, and give a good picture of what will happen to the cement tested in water formation, at lower temperature at longer duration for CCS.

Thanks for
your attention!

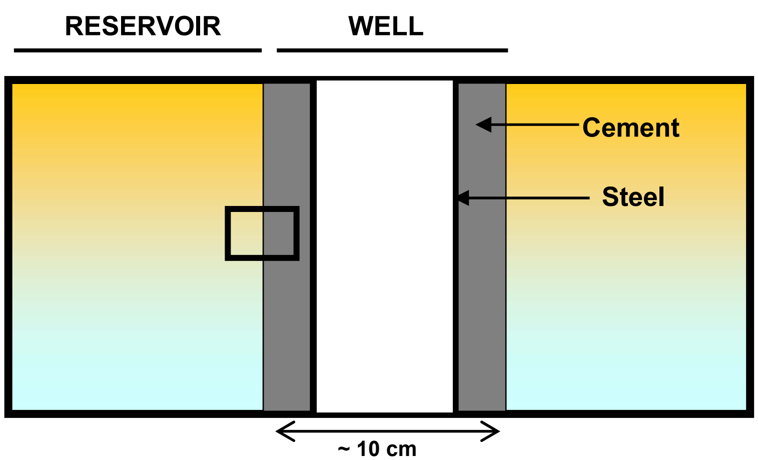
Questions?

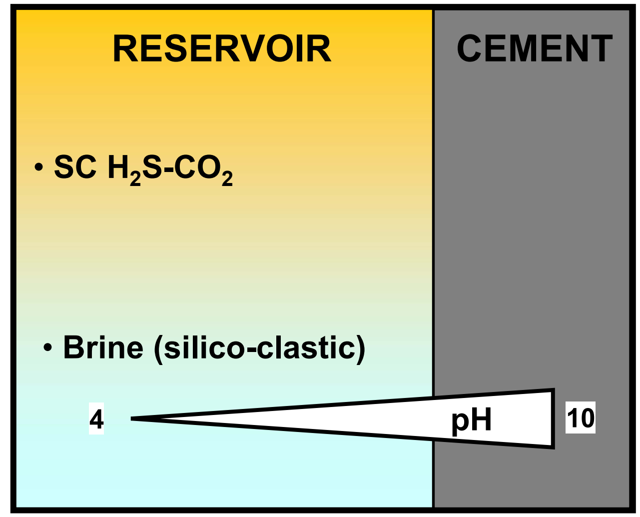
Schlumberger

Well cement ageing in various H_2S-CO_2 fluids at high pressure and temperature - Experiments & modeling

N. Jacquemet (BRGM)
J. Pironon (Univ. Henri Poincaré)
V. Lagneau (Mines Paris)
J. Saint-Marc (TOTAL)

Which behavior of cement with the reservoir fluids ?





• Different cement-fluid contacts

• High P-T conditions

→ Alteration of the cement

SCOPE OF THE STUDY:

Mineralogical, textural and porosity changes of cement in such an environment

Géosciences pour une Terre durable
brgm

Plan

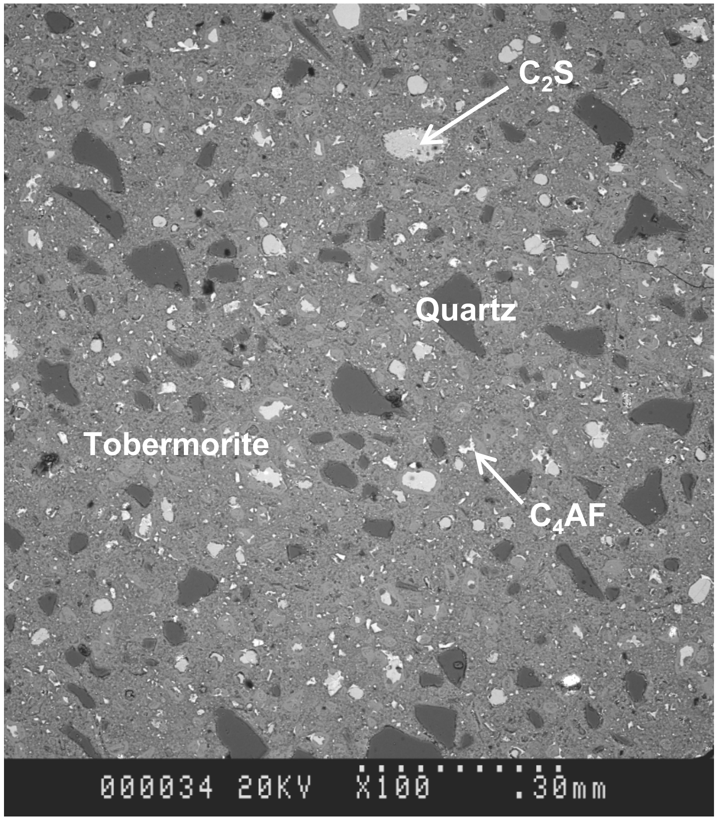
- Starting materials
- Experimental results
- Modeling results

Starting materials

Starting materials: analogues of deep well materials

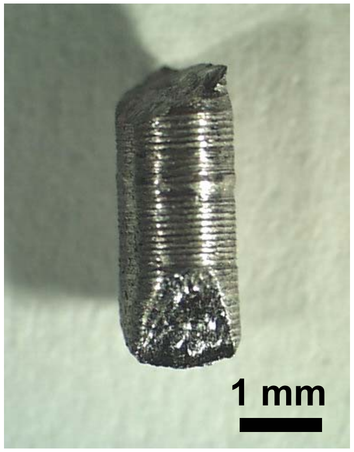
> Cement formulation and cure

- The slurry has a typical composition of deep well cement slurry (Portland Class G-HSR + silica flour, W/C=0.55)
- hydrothermal curing conditions: 210 bar, 140°C, 8d



> Cement characterisation

- Assemblage of 11A Tobermorite + Quartz
- Water porosity: 0.4



> Steel

- Used for casings
- Low C content (98 mol% of Fe°)

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Experimental results

Géosciences pour une Terre durable

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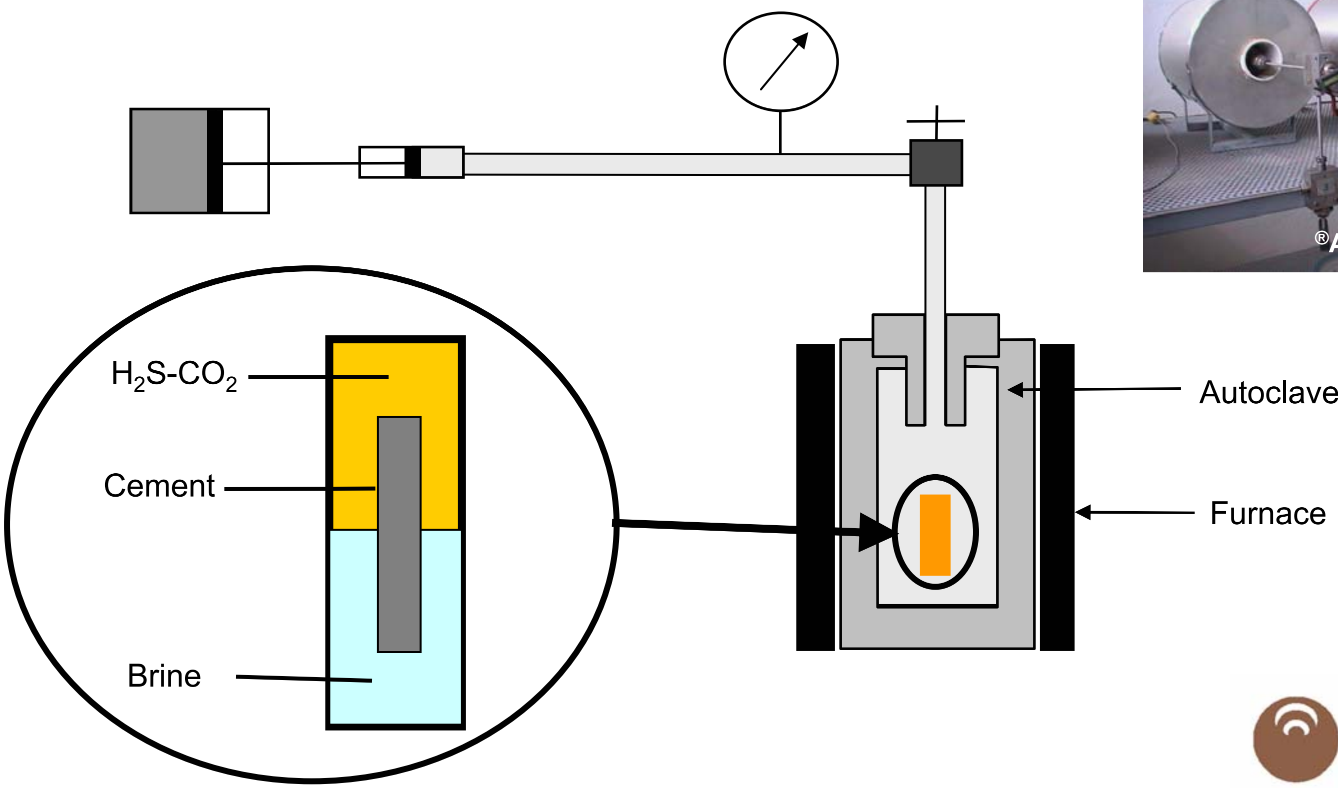
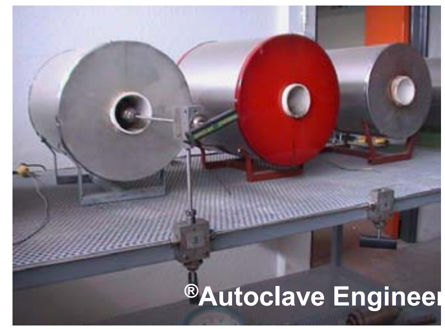
Experimental apparatus

- **Use of micro-reactors (flexible gold capsules of 2 cc)**
- **Putted in hydraulic pressure autoclaves**





Cement analysis protocol

> **Optical microscopy**

> **X-Rays Diffraction (XRD)**

> **Scanning Electron Microscopy (SEM): conventional use (texture and local elemental analysis) and elemental mapping**

> **Raman micro-spectroscopy: mineralogical mapping**

> **Water porosimetry**

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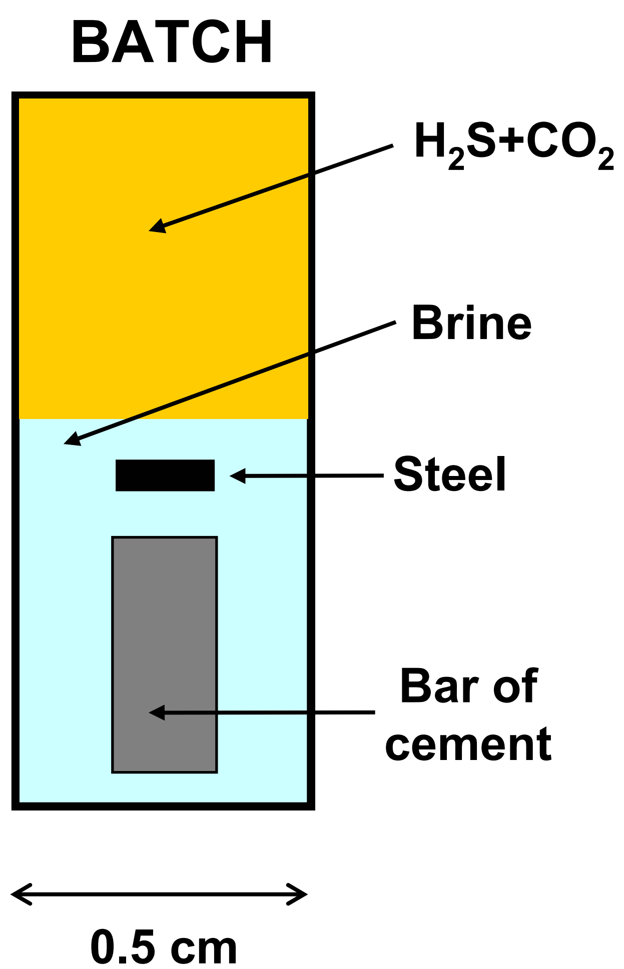
Experimental conditions (1): based on TOTAL's reservoir specifications



- **<u>Brine:</u> NaCl brine (150 g/l)**
- **<u>P-T couple:</u> 500 bar-120°C**
- **<u>Gas:</u> 0.66 H_2S+0.34 CO_2**
- **<u>Durations:</u> 15, 60 days**
- **<u>F/C:</u> 1 to 2**

Géosciences pour une Terre durable
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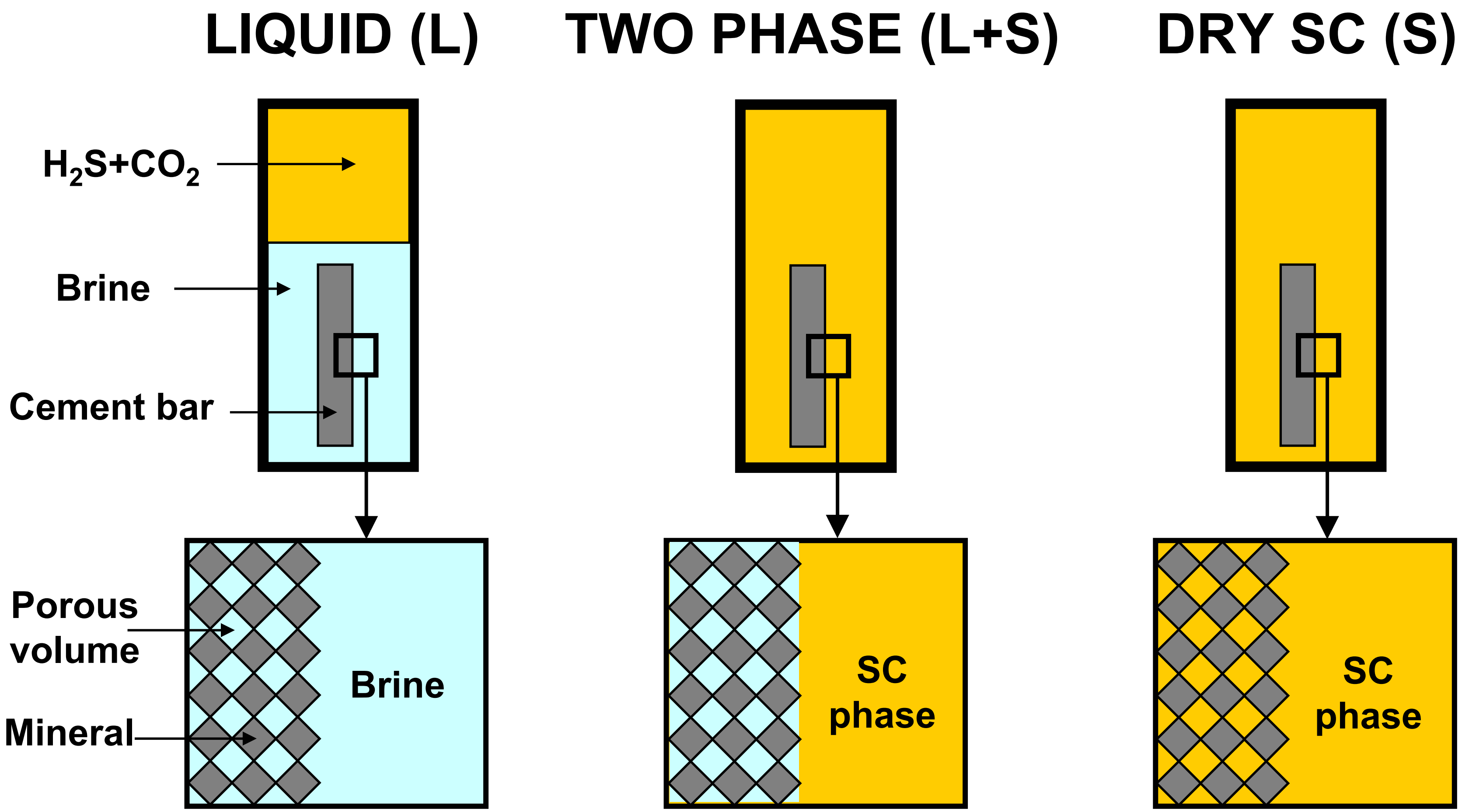
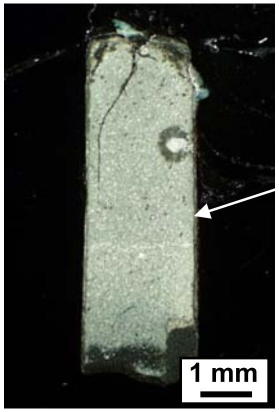
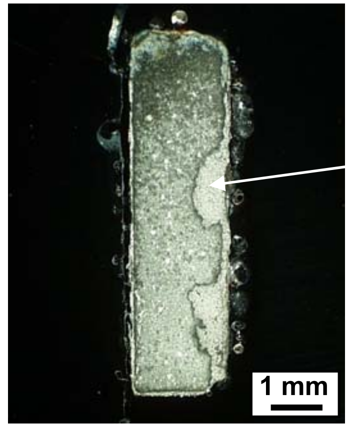
Experimental conditions (2): three types of fluid environments

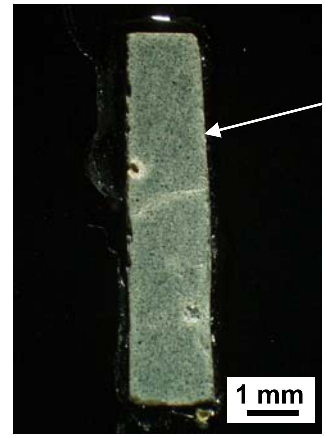


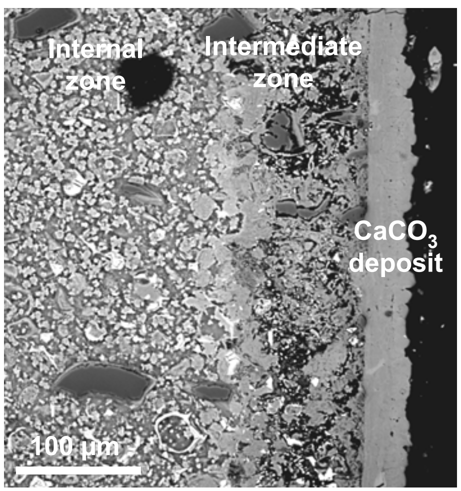
Different carbonation profiles according to the fluids

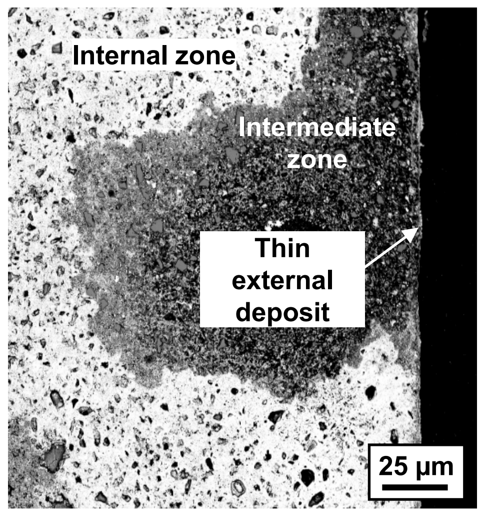
L | **L+S** | **S**

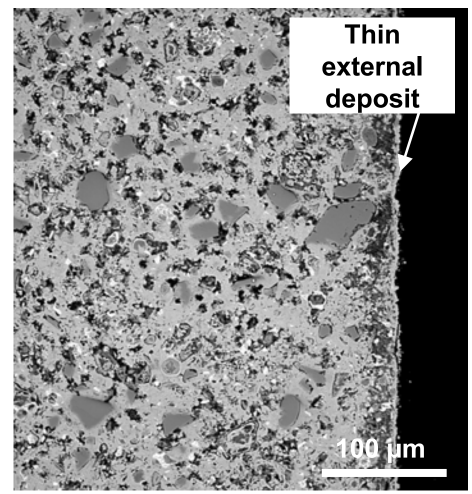












L
- **Constant thickness front**
- **Massive deposit of $CaCO_3$**
- **No change from 15 to 60 days**

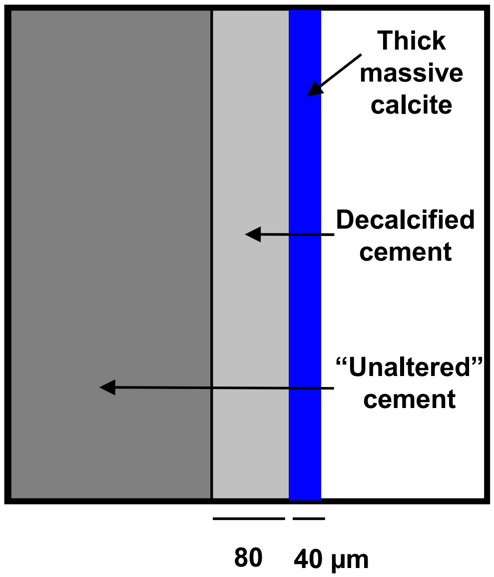
L+S
- **Variable thickness front**
- **Thin $CaCO_3$ deposit**

S

Total homogeneous alteration

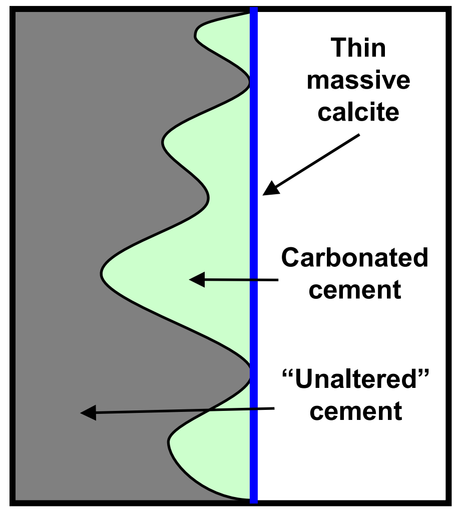
Schematization of the carbonation profiles

L



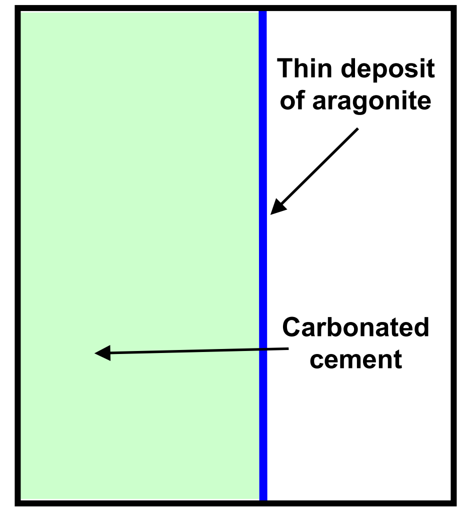
Partial carbonation - global mineralogy unchanged

L+S



Partial carbonation - global mineralogy unchanged

S



full carbonation - global mineralogy changed

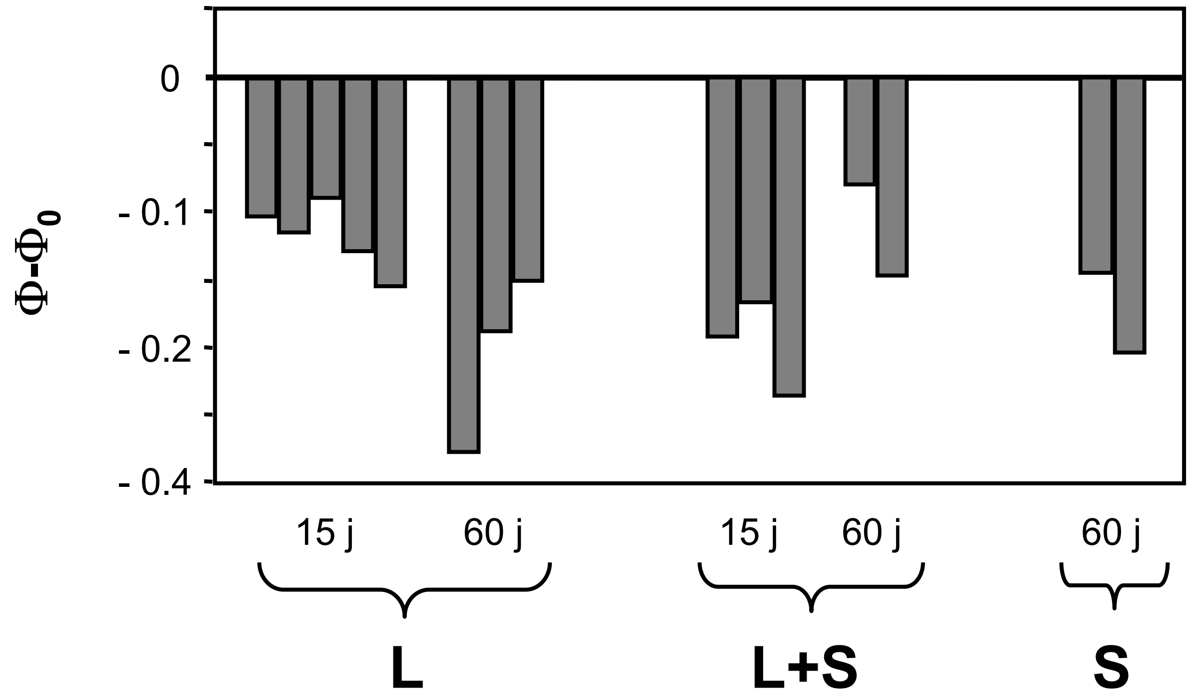
Processes:

Diffusion of C and Ca species → Massive deposit of calcite, blocks the diffusion, stops the front progression

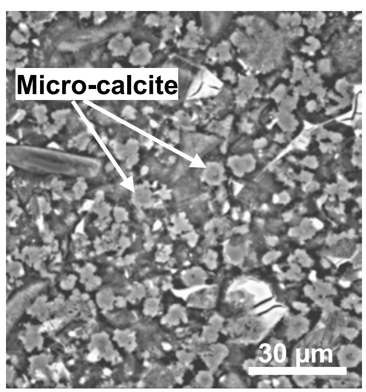
Intrusion of the SC into the porous volume → digitations

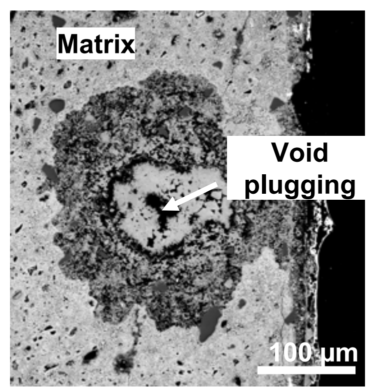
Total carbonation (favored by the absence of liquid water and optimal diffusion of the SC CO_2)

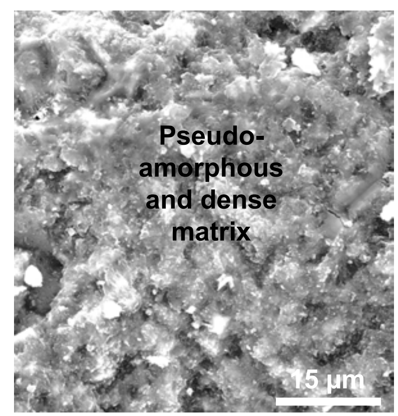
Porosity changes



> **Carbonation plugging and texture conservation**



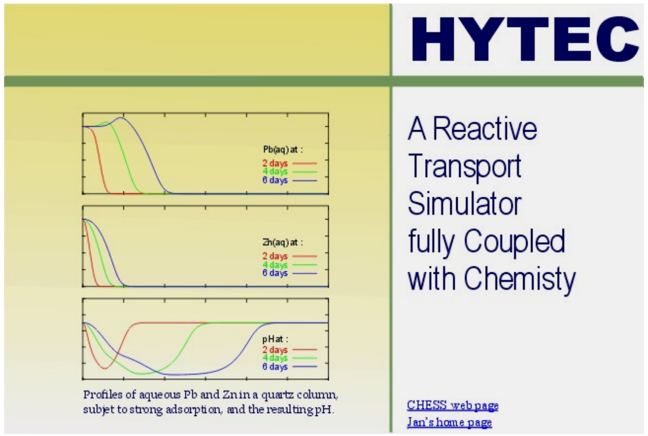




Modeling results

Simulation of experimental results

- **Use of the coupled chemistry-transport code HYTEC (Mines Paris)**
- **SCOPE: Reproduction of the carbonation front in the liquid phase after 60 days duration**



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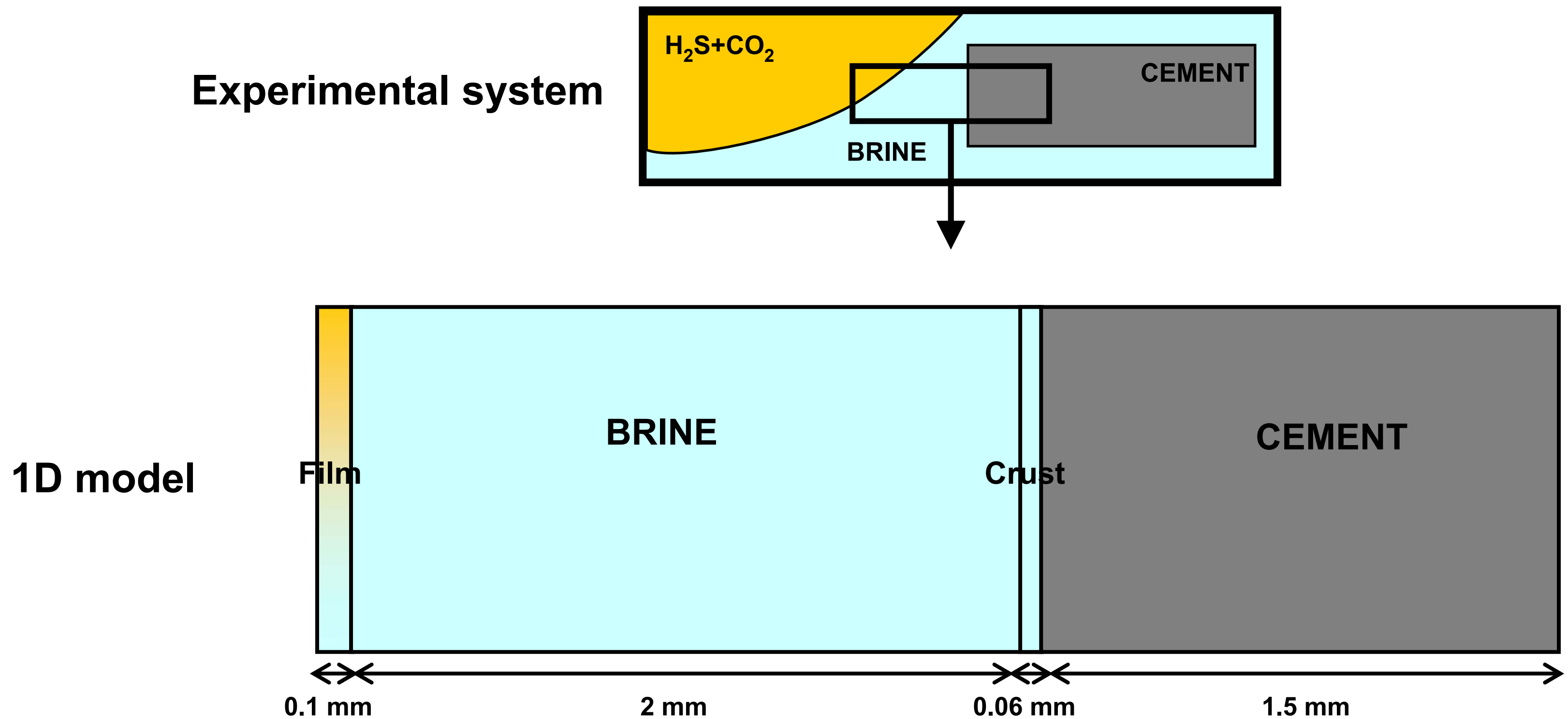
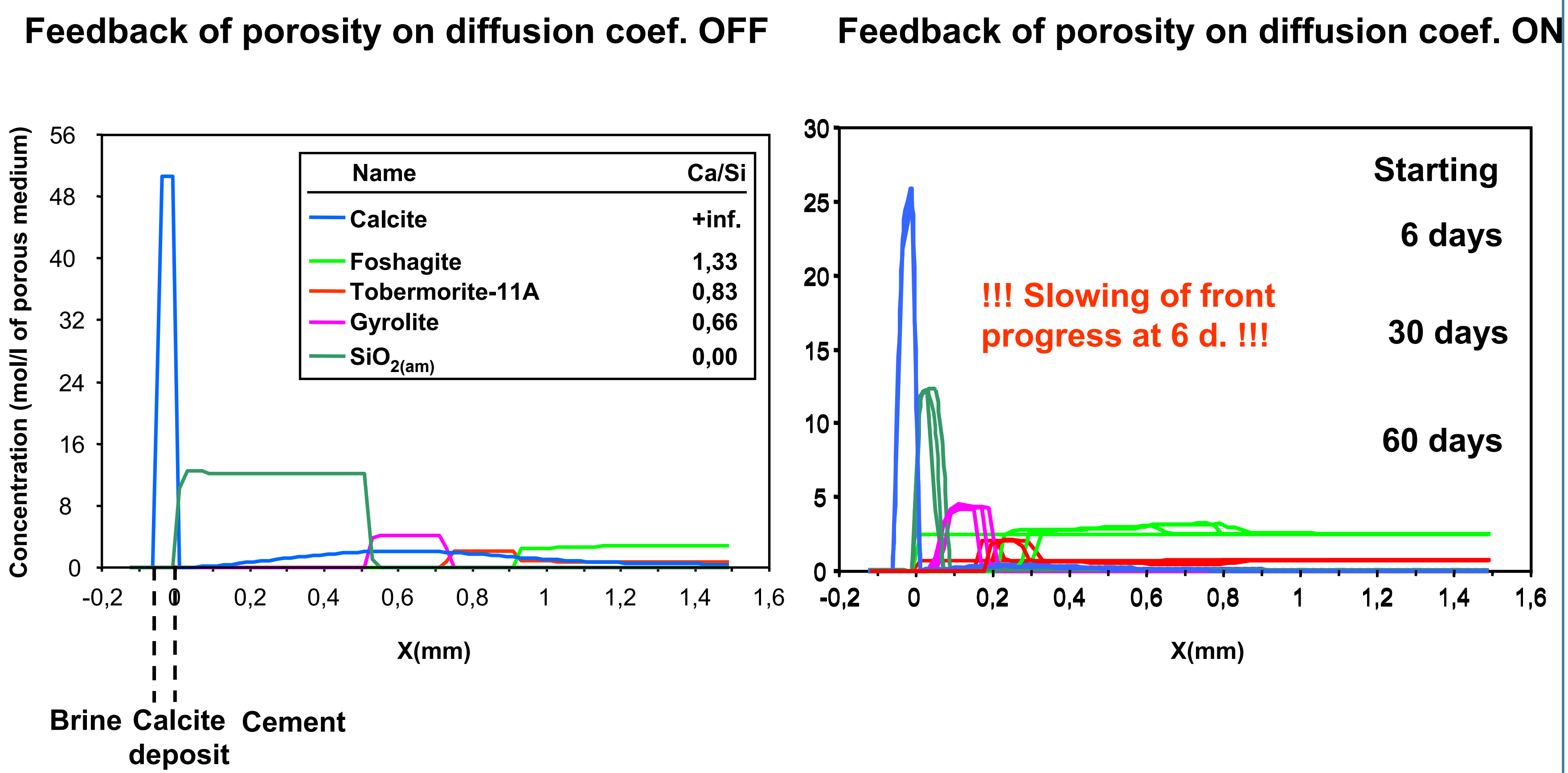
Experimental system vs. numerical system



- **Initial Mineralogy/Geochemistry, Porosity, Diffusion coefficients: experimental & literature values**
- **Transport: diffusion-controlled and sensitivity analysis (switching on/off) on the feedback of porosity on diffusion coefficients**
- **Reactions: thermodynamically controlled (CTDP database) except for calcite precipitation (kinetically controlled)**

Modeling results at 60 days



> **The slowing of front progress after few days confirms the calcite deposit being responsible of diffusion blocking**

Conclusion & Perspectives

Conclusion

> Experimental approach

- The cement mineralogy is influenced by CO_2 via carbonation and is weakly influenced by H_2S (sulfidation of ferrites, minor phases)
- The degree of carbonation is 1st order controlled by the fluid phase contacting the cement

  → Carbonation is maximal within dry SC and minimal with liquid water
- Petrographic evolution of cement :
  - Conservation of initial mineralogy (except in dry SCP)
  - Conservation of texture
  - Improvement of porosity
  - Calcite coating (only in liquid)

> Modeling approach

- Reproduced the mineral zonation and confirmed the diffusion-blocking role of the calcite coating
- But the front thickness is 3 times higher

Perspectives

> Perspectives of modeling at BRGM

- Use of the code TOUGHREACT (LBNL) to simulate the experimental results from:
  - This study
  - Other studies (CO2GEONET European project)

- Final goal of modeling: upscaling to Near-Field Well bore Environment scale

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Thank you for your attention

Additional slides

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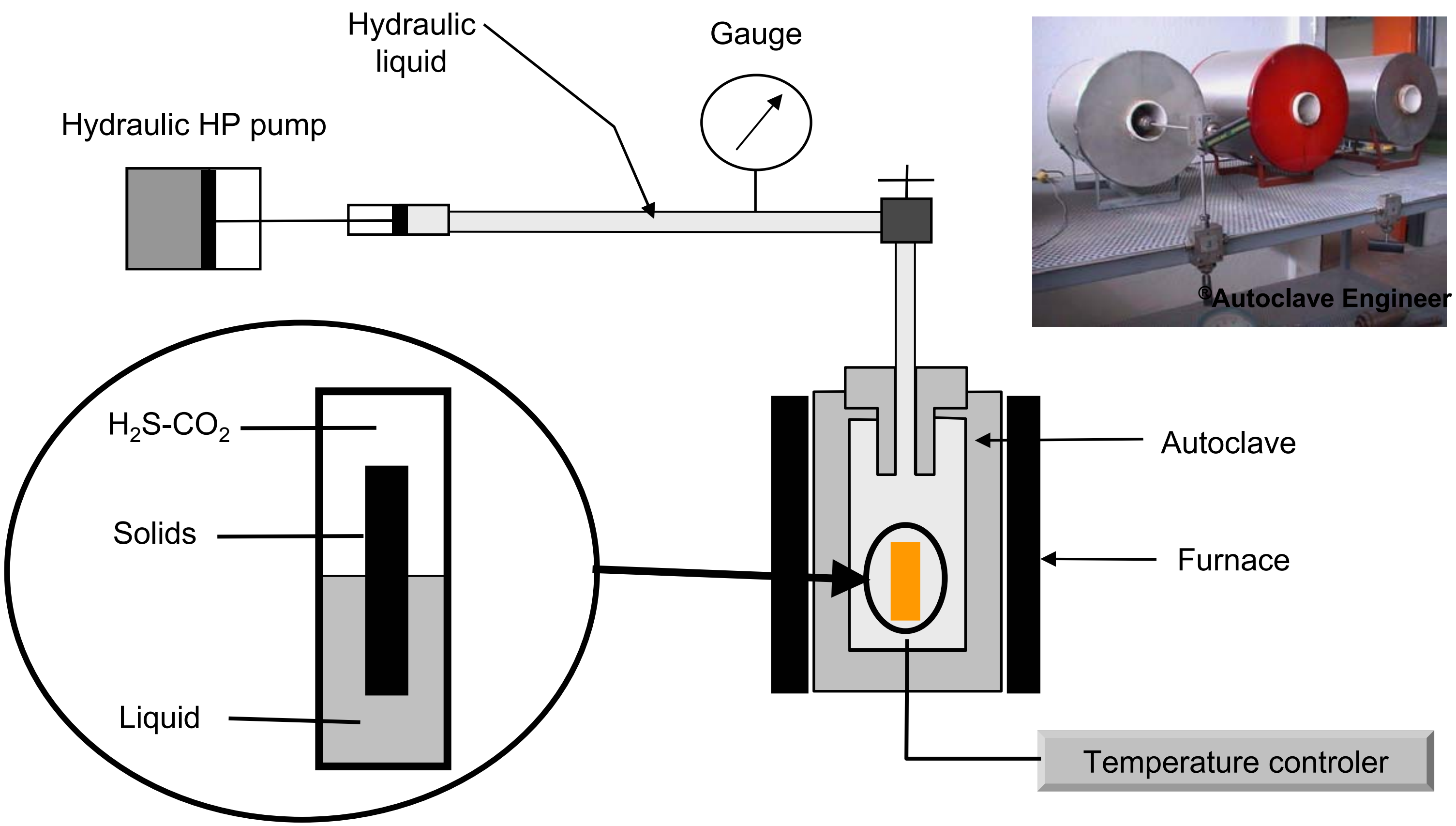
The micro-reactors and autoclaves

- Respect of geological relevant P-T

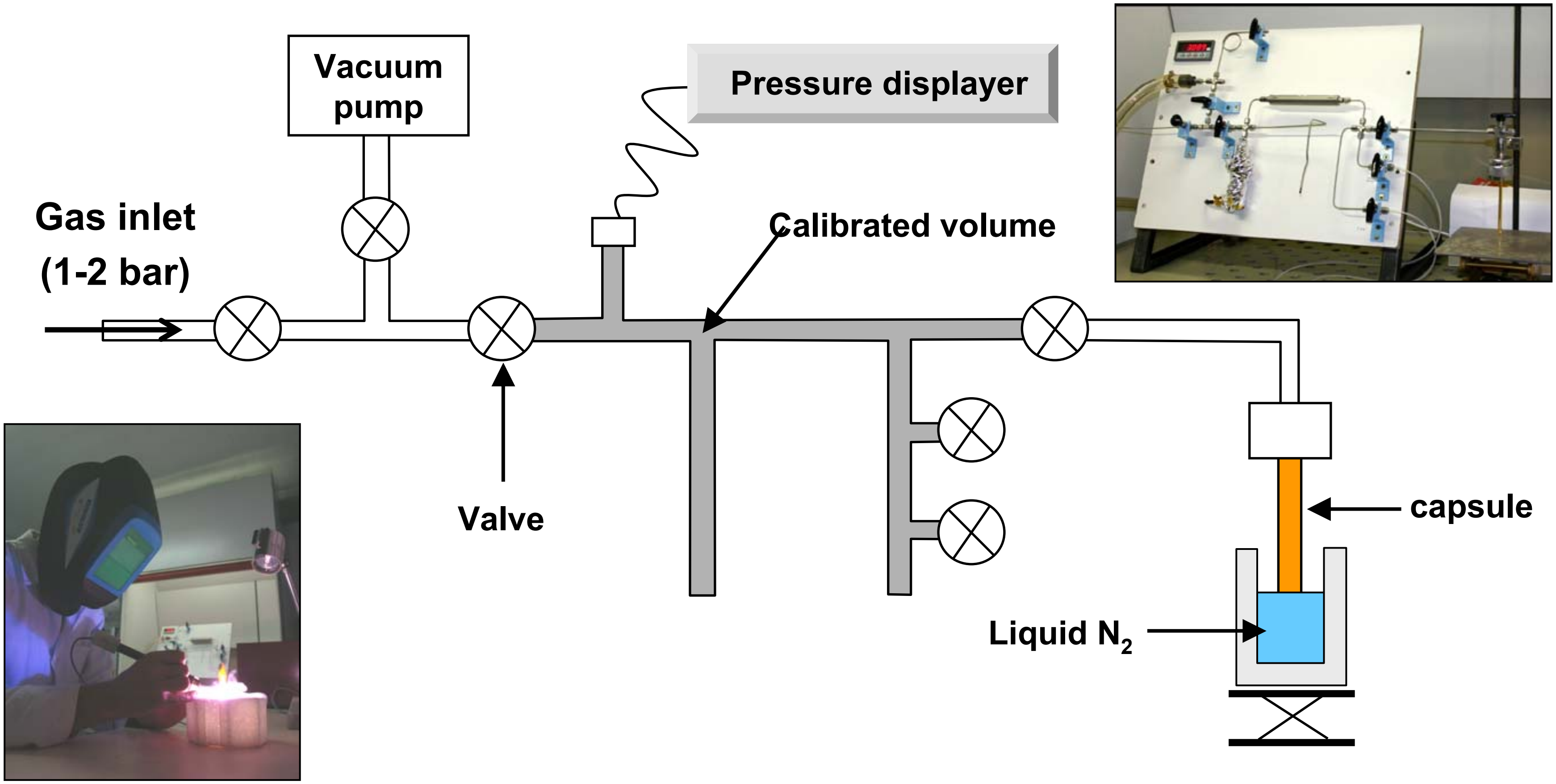
→ Hydraulic pressure autoclaves (Max. cond.: 1000 bar-450°C)

- Systems with high concentration of gas – Safety rules

→ Use of micro-reactors (gold capsules of 2 cc)



The secured gas loading in gold capsules



- Gas inlet and apparatus placed in hood in safe area
- The cryo-condensation allows a low pressure loading
- Precise mass of gas in the capsules

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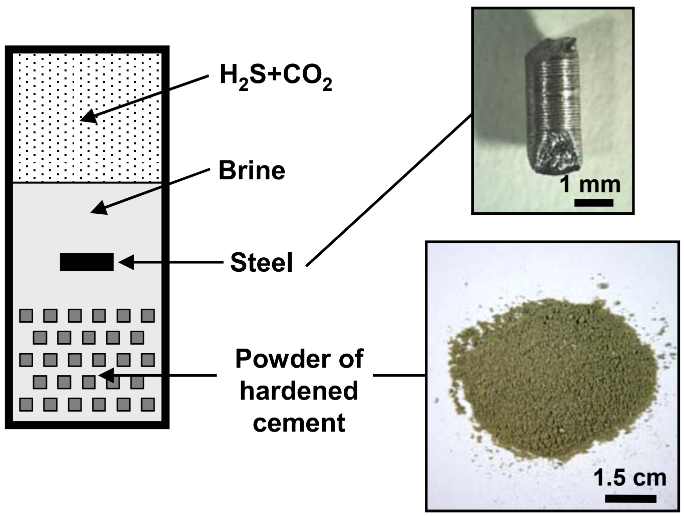
Terminology in cement chemistry and specific mineralogy

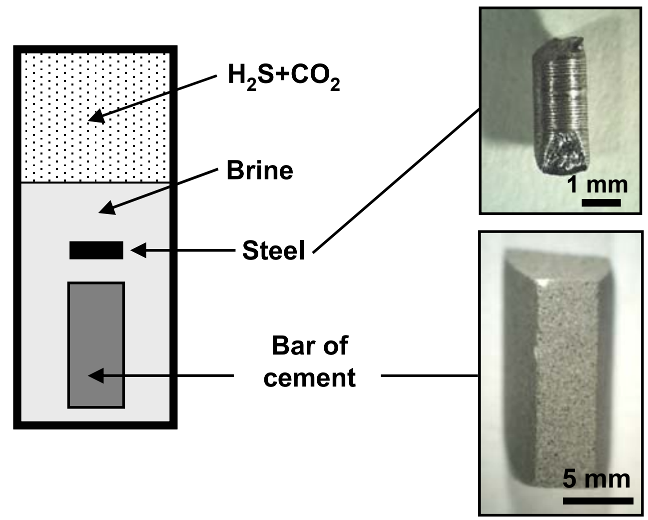
Mineral name	Simplified formula	Mineralogic formula
<u>Hydrothermal C-S-H</u>		
Tobermorite	$C_5S_6H_5$	$Ca_5Si_6O_{16}(OH)_2 \cdot 4H_2O$
Xonotlite	C_6S_6H	$Ca_6Si_6O_{17}(OH)_2$
<u>Other minerals</u>		
Quartz	S	SiO_2
Bicalcium silicate	C_2S	Ca_2SiO_4
Ferrite	C_4AF	Ca_2AlFeO_5

Two forms of cement and geological relevant conditions

Cement under the form of powder



Cement under the form of bar



• Optimisation of the reactive surface --> homogeneous reactivity AND advanced reaction state

• Proper minerals reactivity

"Real" texture of the well cement

RESERVOIR ⟺ EXPERIMENTATION (times from 15 to 60 days)

• FORMATION WATER:	**NaCl brine (150 g/l)**
• TOTAL PRESSURE:	**500 bar**
• TEMPERATURE:	**120°C, 200°C**
• GAS:	**66mol% H_2S + 34mol% CO_2**

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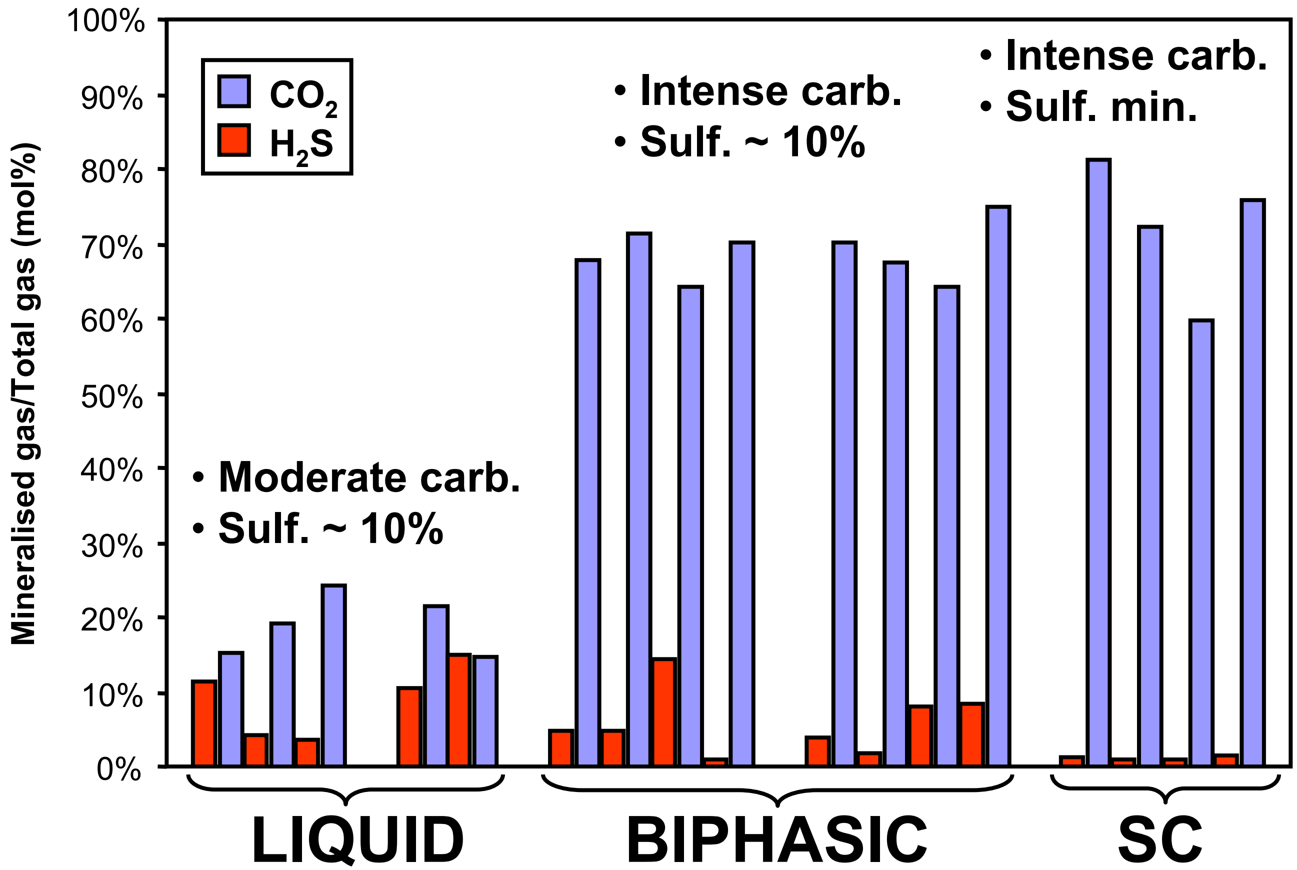
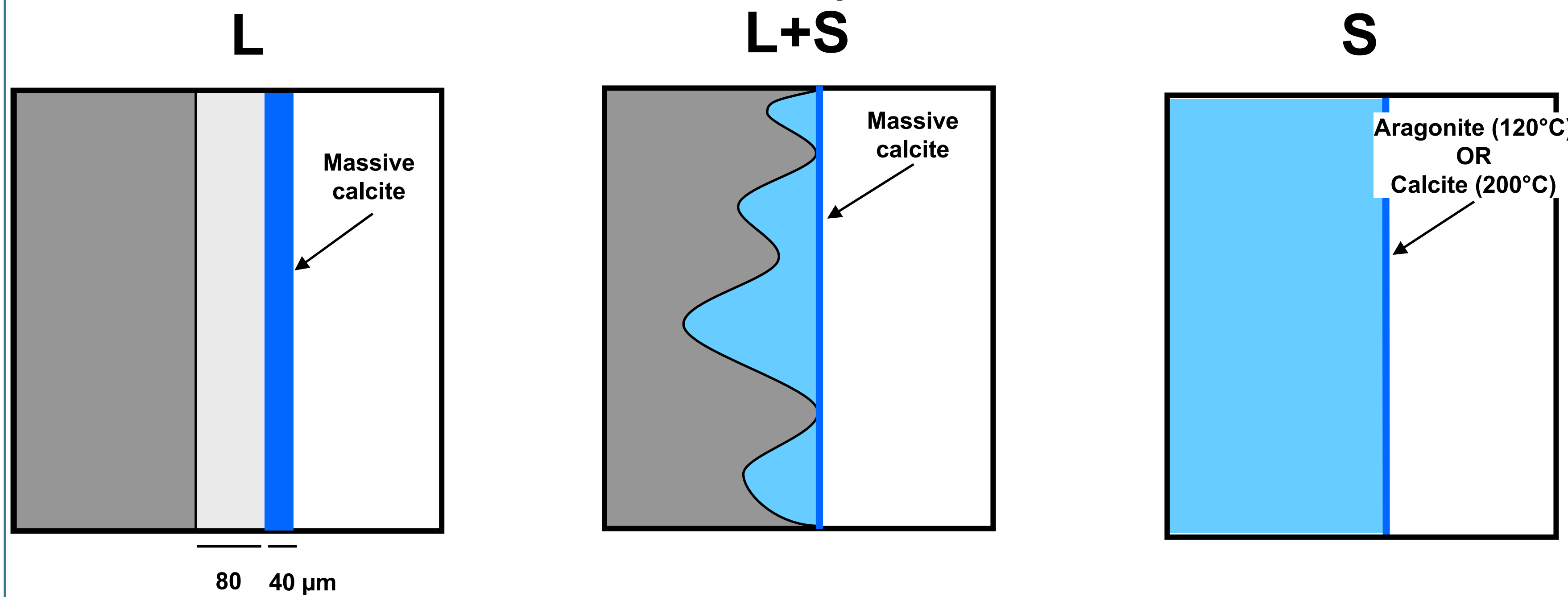
Two degrees of carbonation and sulfidation

SIMPLIFIED REACTIONS:

- **Carbonation**: $CaO.SiO_2.H_2O + CO_2 \rightarrow CaCO_3 + SiO_2.H_2O$
- **Sulfidation**:
  - $Fe° + H_2S \rightarrow FeS + H_2$
  - $Ca_2AlFeO_5 + 2\ H_2S \rightarrow FeS_2 + \dots$ (200°C)



Schematization of the alteration profiles



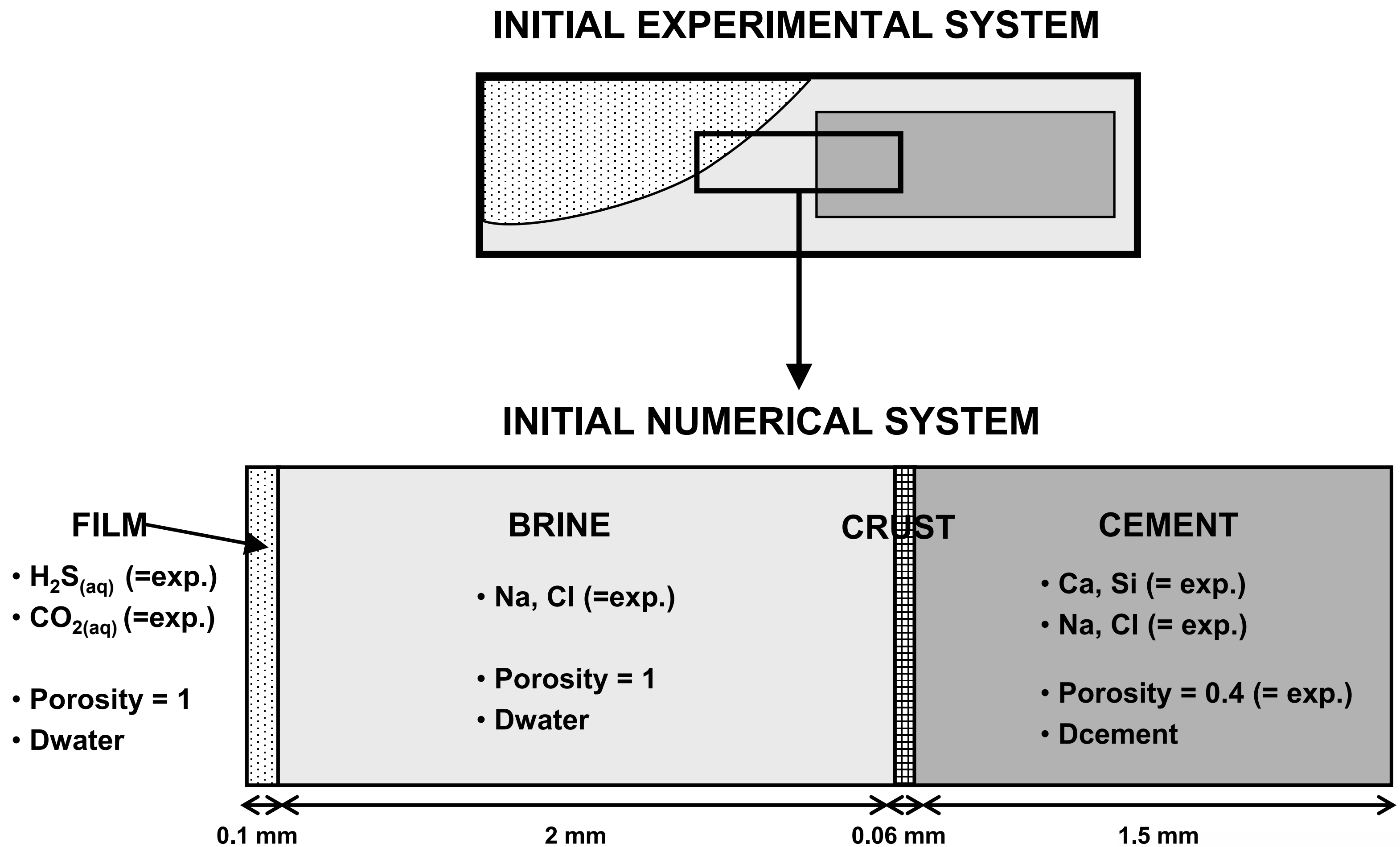
	“NO ALTERED” CEMENT		DECALCIFIED CEMENT		CARBONATED CEMENT
	• Hydrothermal CSH		• Silica +/- Ca		• Silica +/- Ca
	• Quartz (dissolved at 200°C)		• Quartz		• $CaCO_3$ (aragonite+calcite)
	• Diffuse calcite		• Traces of calcite		• Quartz

Diffusion of C and Ca species
→ Massive deposit of calcite
→ Diffusive blockage
→ Alteration stopping

Intrusion of the SC into the porous volume
→ digitations

Total carbonation (favored by the absence of liquid water and optimal diffusion of the SC CO_2)

Analogy experimental system – numerical system



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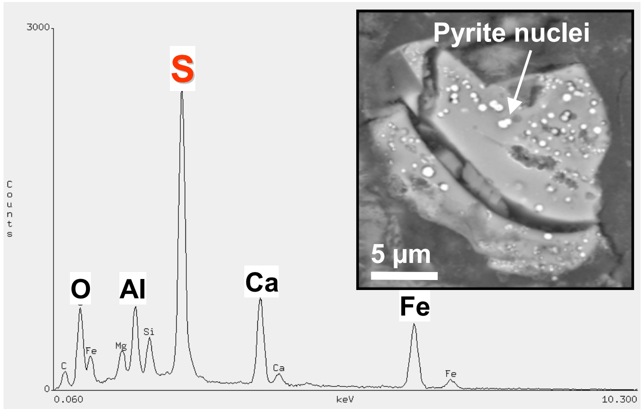
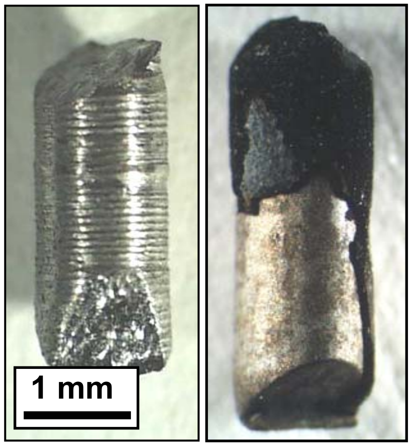
The sulfidation of the iron bearing phases

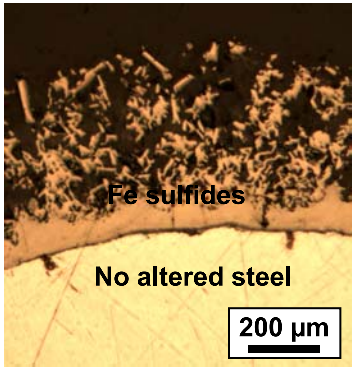
1. IN THE CIMENT: THE SULFIDATION OF THE FERRITES



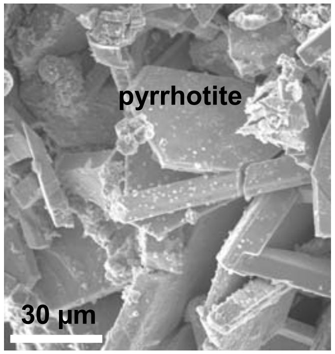
2. THE SULFIDATION OF THE STEEL

$Fe° + H_2S \rightarrow FeS + H_2$





Iron sulfide crust

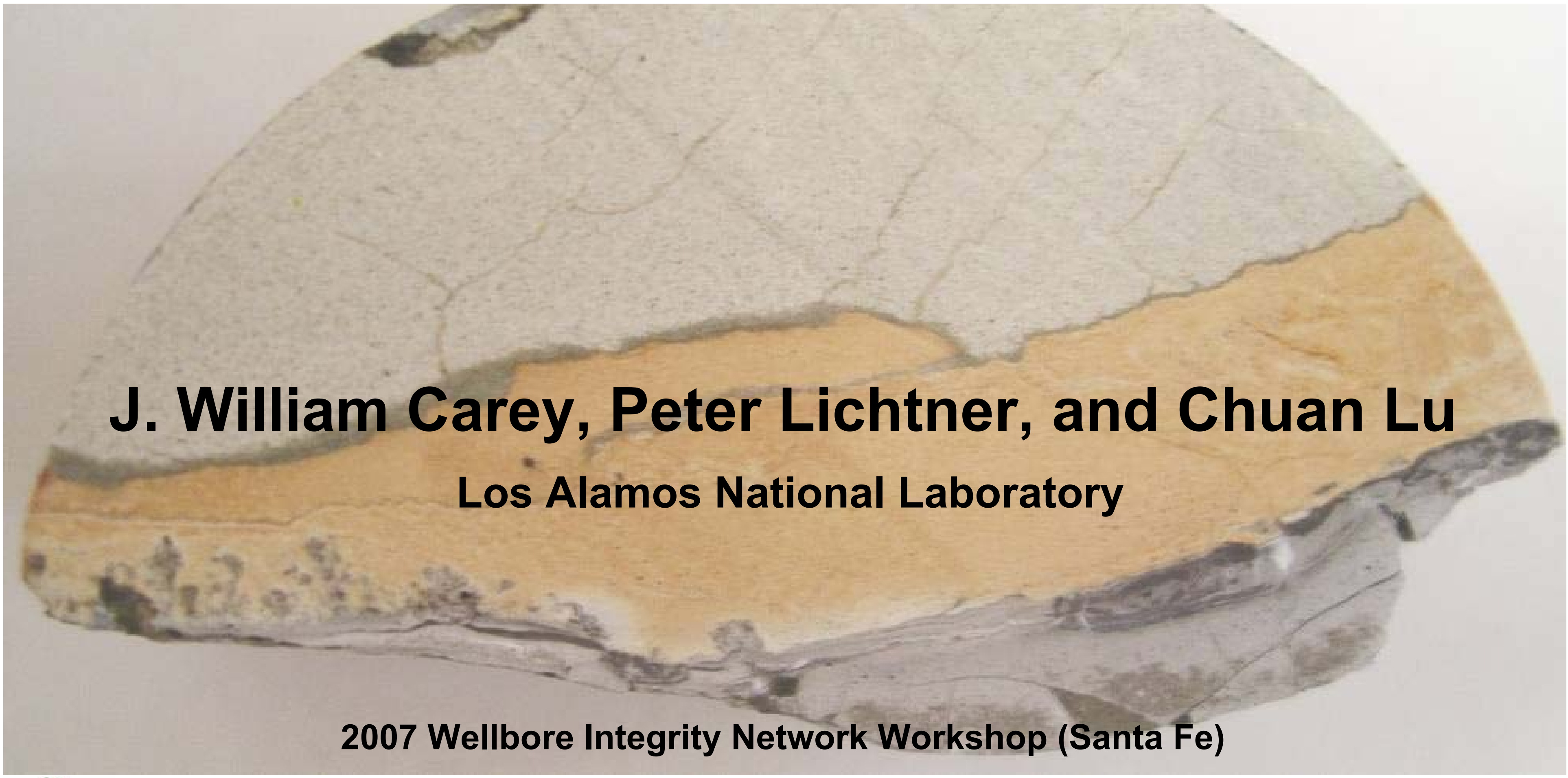


Group of pyrrhotites

Archie's modified law

$$De(\omega) = De(\omega_0)\left(\frac{\omega - \omega_c}{\omega_0 - \omega_c}\right)^a$$

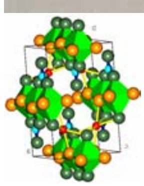
Simulation of Cement Reactivity with CO_2 in the Wellbore Environment



J. William Carey, Peter Lichtner, and Chuan Lu

Los Alamos National Laboratory

2007 Wellbore Integrity Network Workshop (Santa Fe)



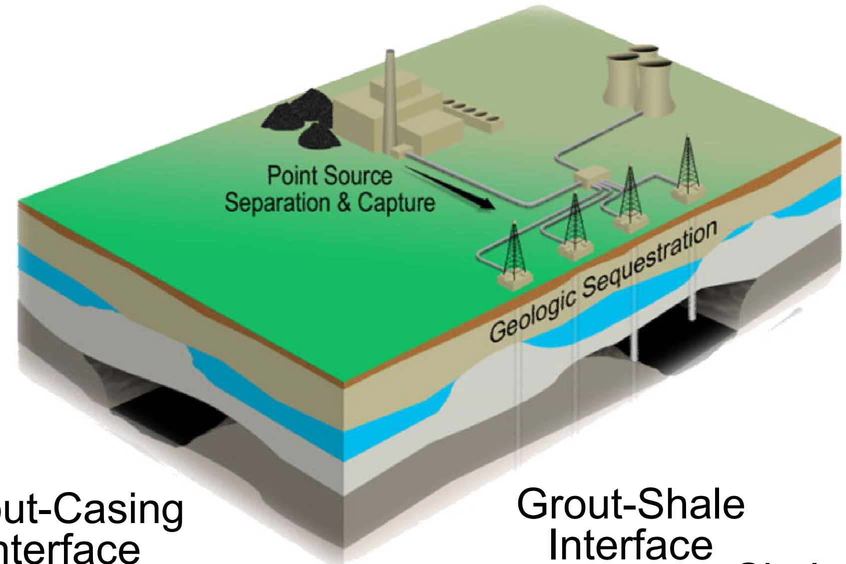
Acknowledgements: DOE's National Energy and Technology Laboratory (04FE04-07)

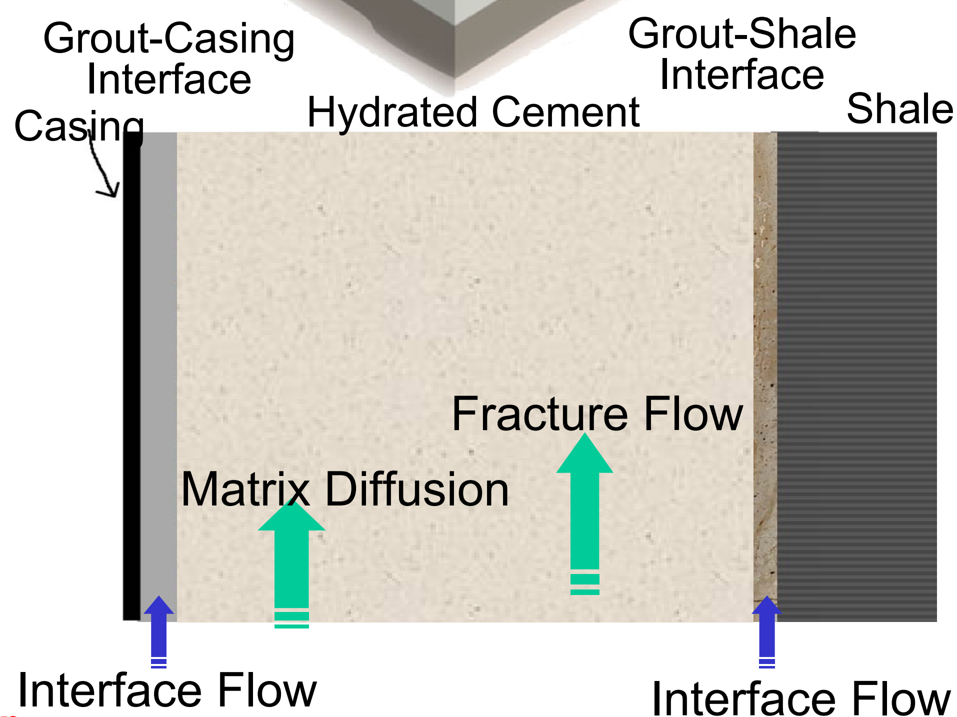
LA-UR-06-0636

Motivation: Model the long-term integrity of wellbore cement exposed to CO_2

- **Determine mode of CO_2 interaction with cement**
- **Develop model of changes in effective cement permeability as function of CO_2 reaction**
- **Need initial conditions of interfaces (width, porosity, effective permeability)**
- **Need initial drive (diffusion, buoyancy, capillary, gradient)**
- **Calculate changes in interface permeability**
- **Ultimately, couple with geomechanics**

- **How does the two-phase system affect reaction rates? Will CO_2 penetrate cement primarily by diffusion, pressure-driven flow, or capillary pressure?**





LA-UR-06-0636

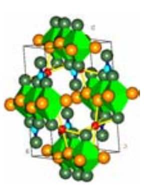
Effect of Two-Phase Behavior on CO_2 Reactivity with Cement

1-D Calculations

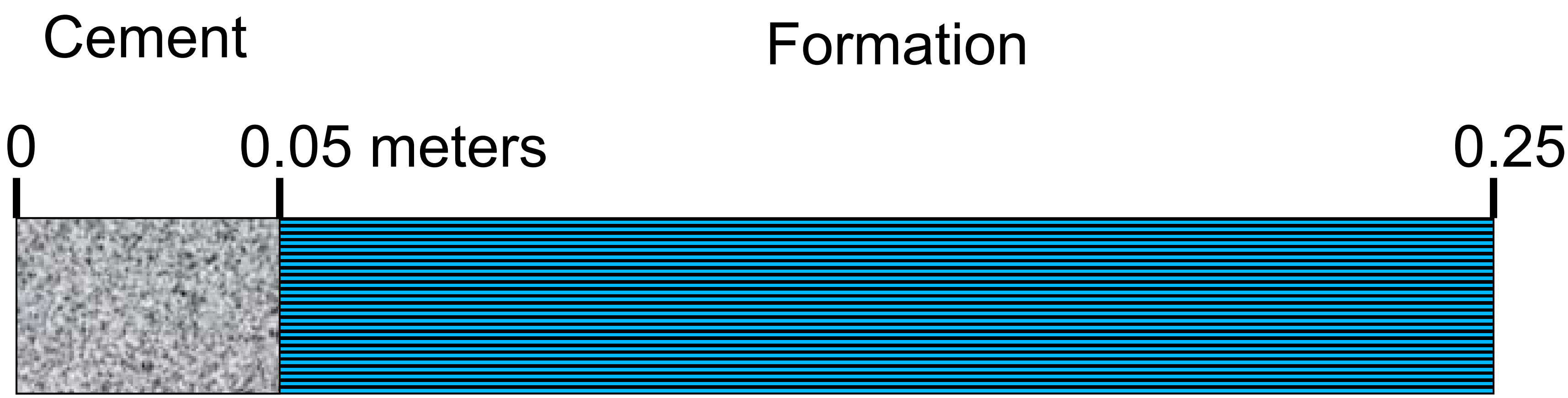
- Role of capillary pressure properties of cement, shale, and reservoir rocks
- Comparison with no-flow (diffusion) results

2-D Calculations

- Problem set-up and boundary conditions
- Preliminary results for flow-only case



LA-UR-06-0636



38% C-S-H (x_{SiO2}=0.36, Ca/Si = 1.78)

15% portlandite

14% monosulfate

3% hydrogarnet

30% porosity

20% illite

7% quartz

1% kaolinite

1% calcite

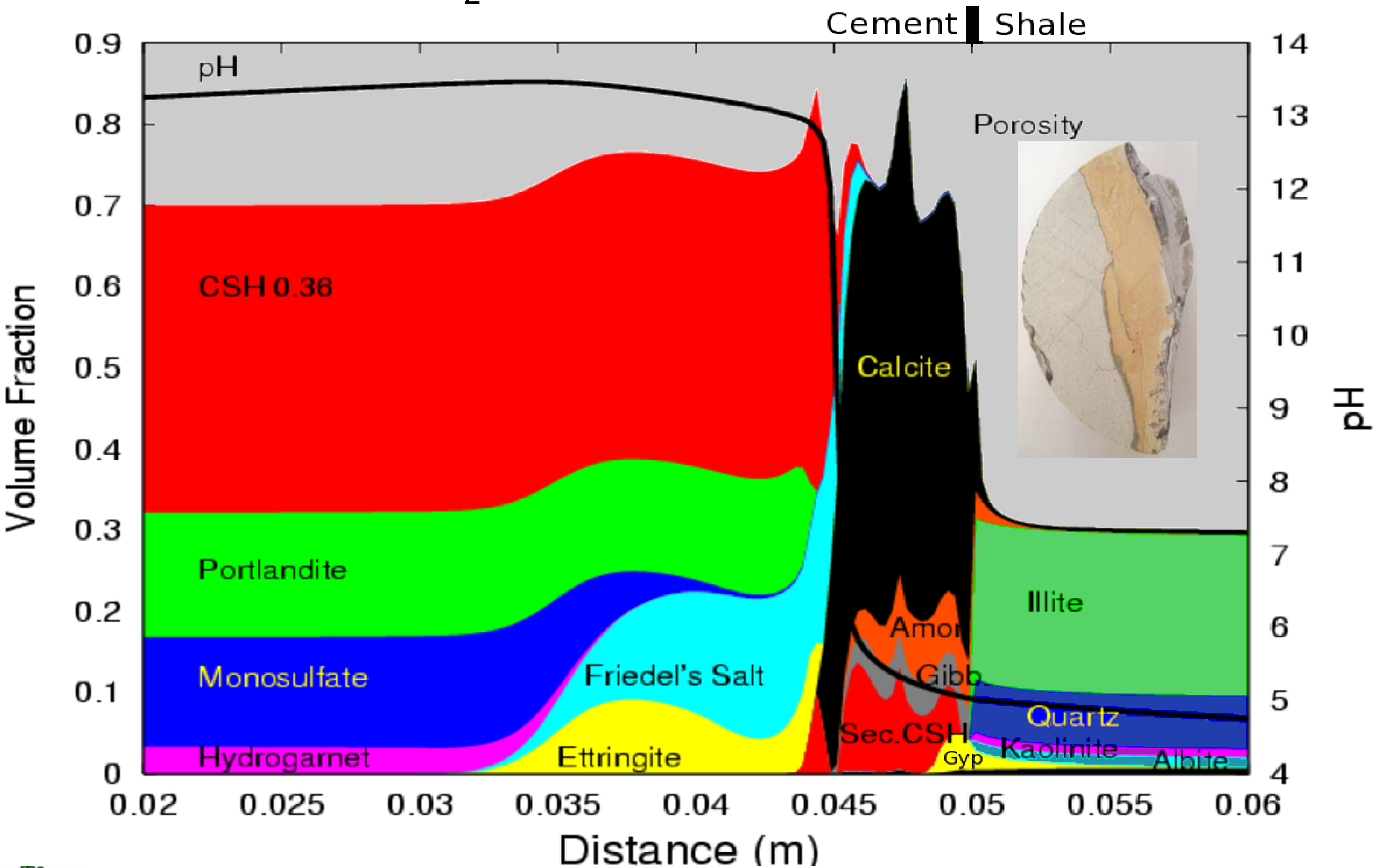
1% dolomite

70% porosity

- 1-D diffusion of CO_2-saturated brine into cement
- 25 ^oC and 179 bars $P(CO_2)$
- Variables: Porosity, tortuosity, reaction rates, and solid solution model [Carey & Lichtner (2007) American Ceramic Society]

LA-UR-06-0636

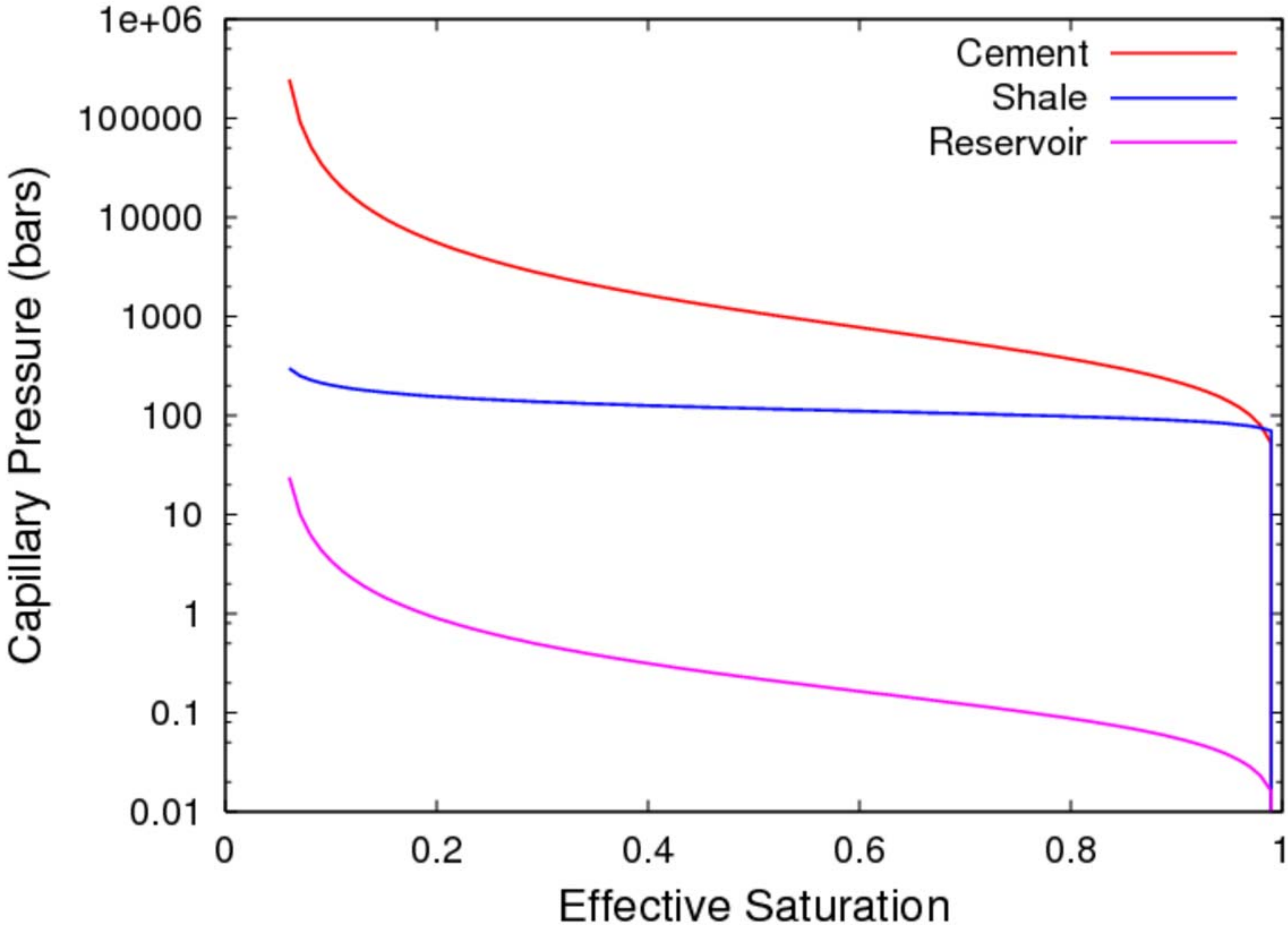
1-D Diffusion of CO_2-Saturated Brine

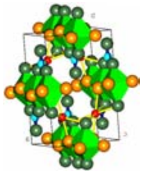


Two-Phase Simulation of Cement-CO_2 Reaction

- **1-D (geometry and mineralogy as before)**
- **Use parallel version of FLOTRAN (PFLOTRAN)**
- **Parameters:**
  - **As before (reaction rates, porosity, tortuosity)**
  - **Without solid solution model**
  - **Need permeability and relative permeability (capillary pressure relations)**
- **Horizontal geometry (as at SACROC)**
  - **CO_2 interaction by diffusion and capillary pressure**
- **Scoping calculations**

Capillary Pressure Relations





(Bennion and Bachu, 2006, SE 99325
Savage and Janssen, 1997, ACI Mat. J.)

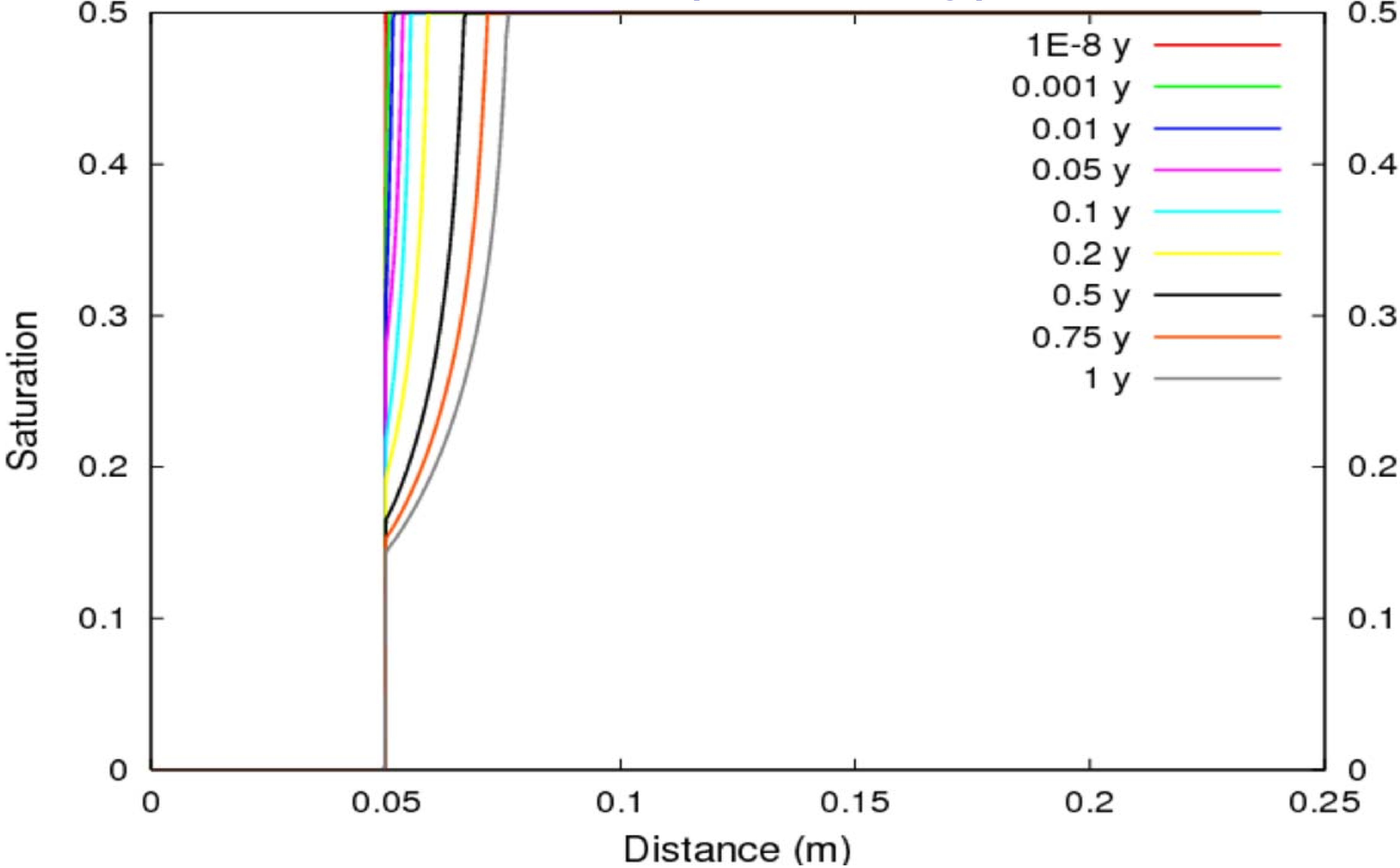
Initial Conditions

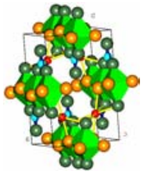
- T = 50 C; P = 200 bars
- Cement: saturated with 1.6 M NaCl brine
- Formation: 50% saturated with brine/CO_2

$$\Psi = (S^{-1/m} - 1)^{(m-1)} / \alpha$$

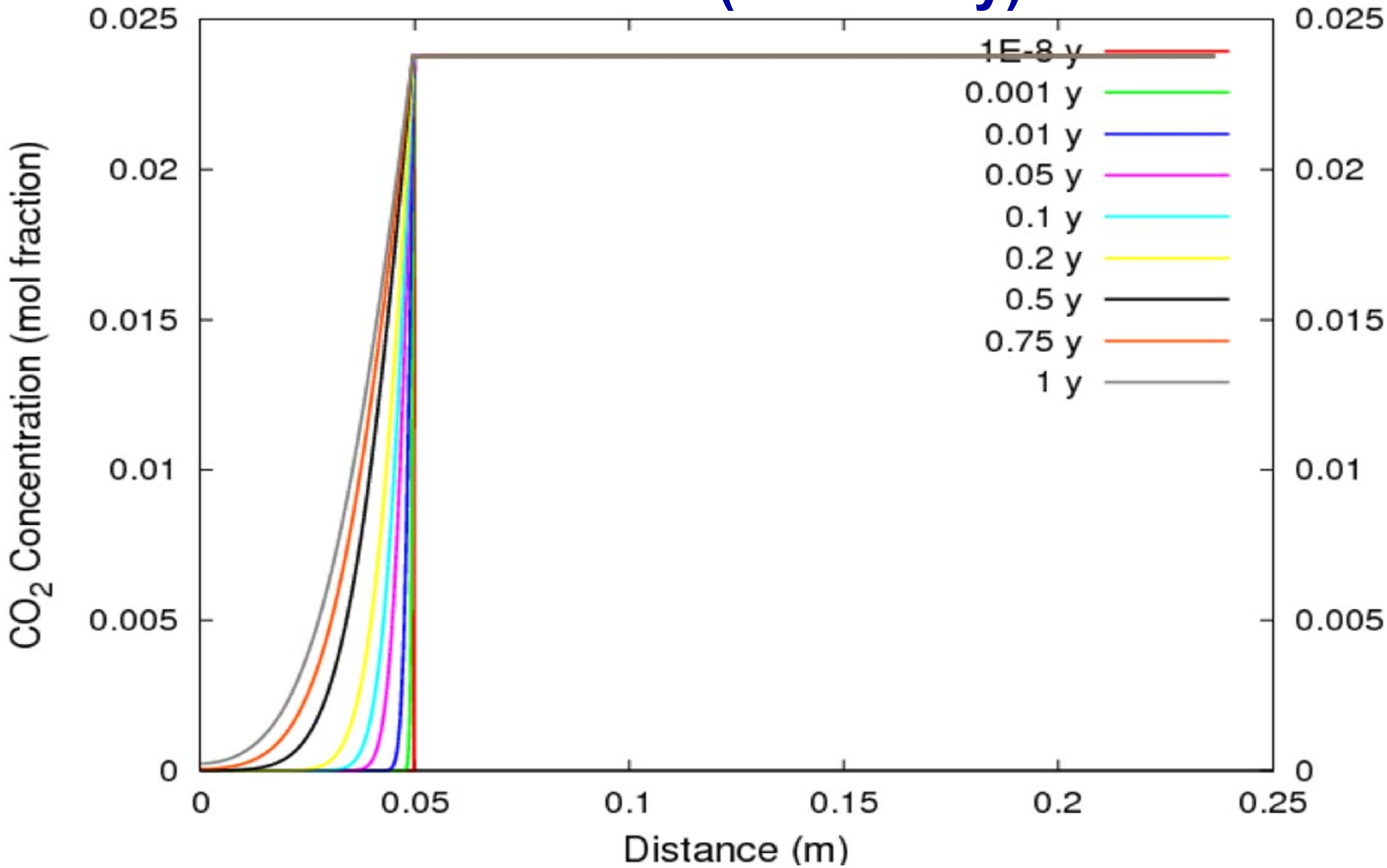
	Perm (mD)	alpha	m	Φ	τ
Cement	0.1	0.0023	0.42	0.4	0.005
Shale	0.1	0.01	0.9	0.2	0.5
Reservoir	100	10	0.5	0.2	0.5

Cement: Reservoir (Flow Only)

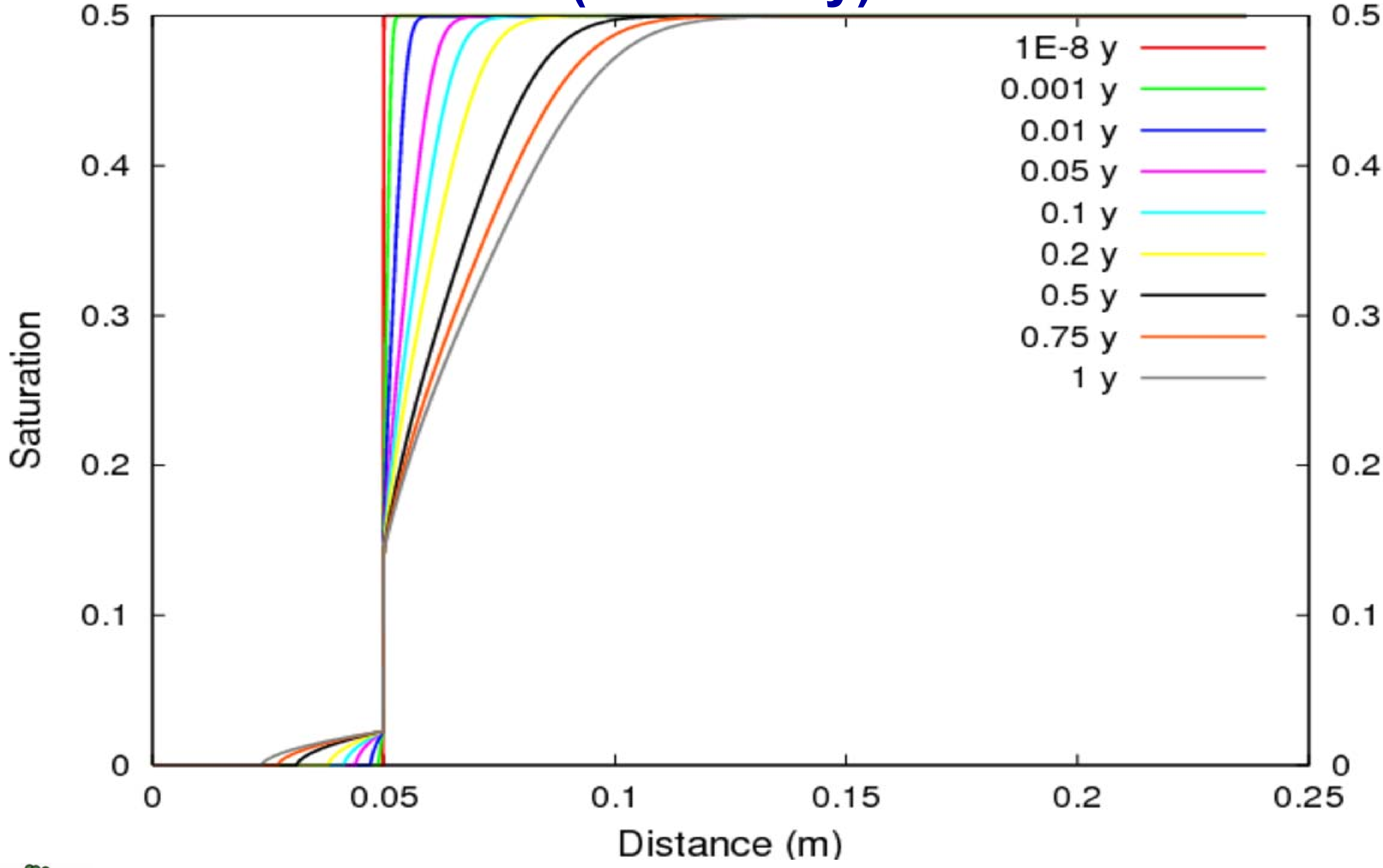




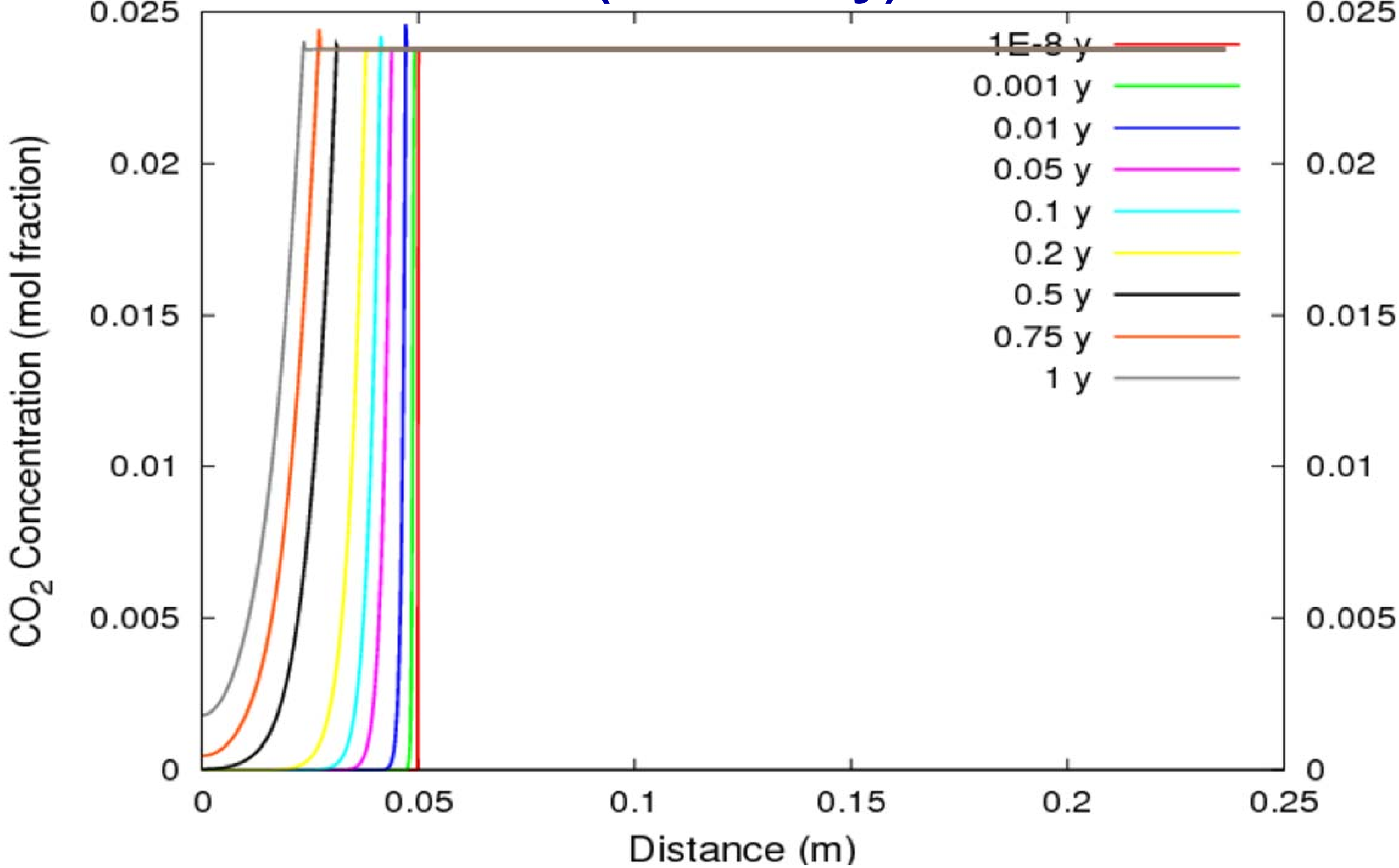
Cement: Reservoir (Flow Only)



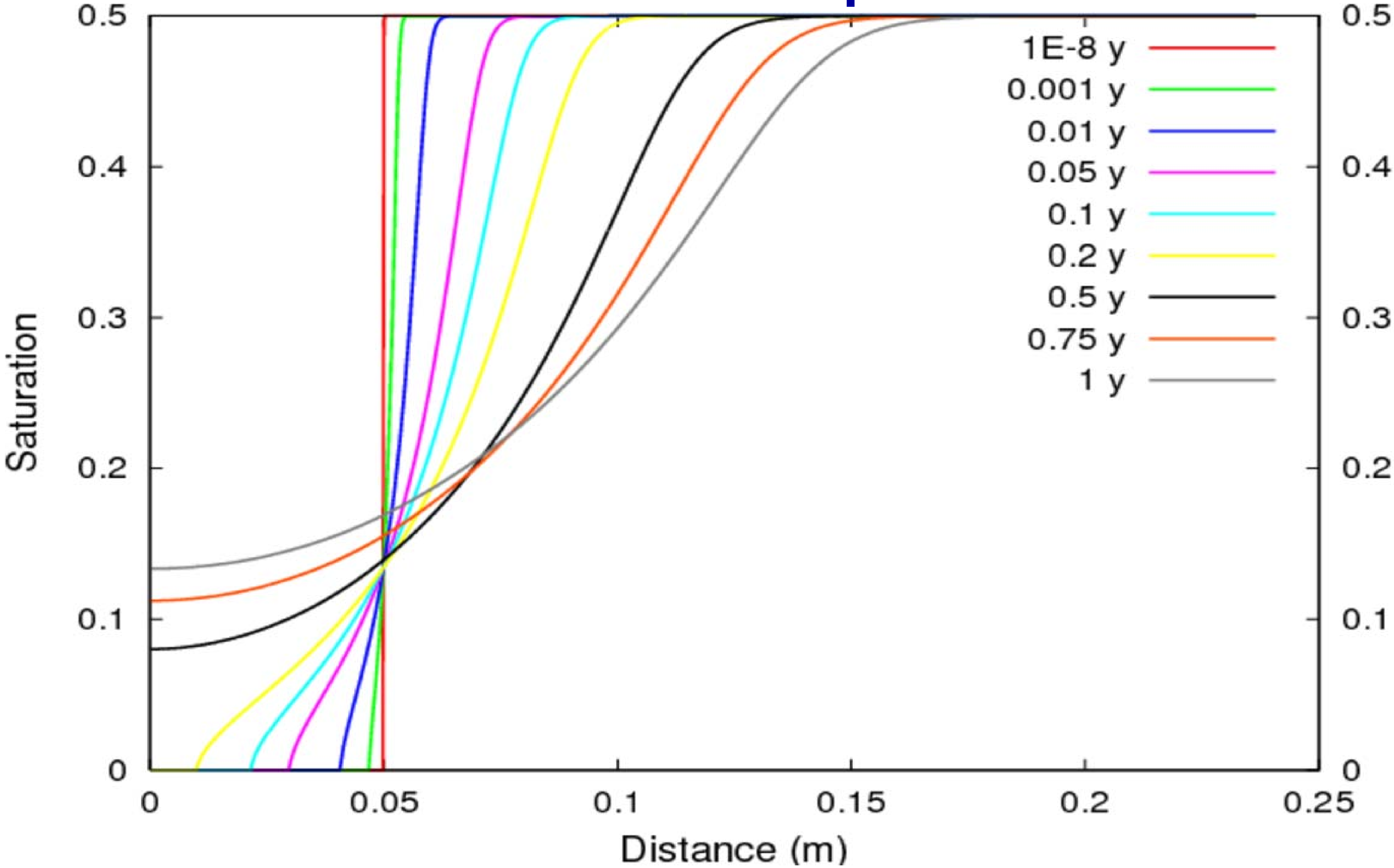
Cement: Shale (Flow Only)

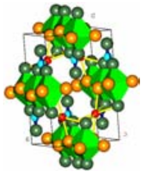


Cement: Shale (Flow Only)

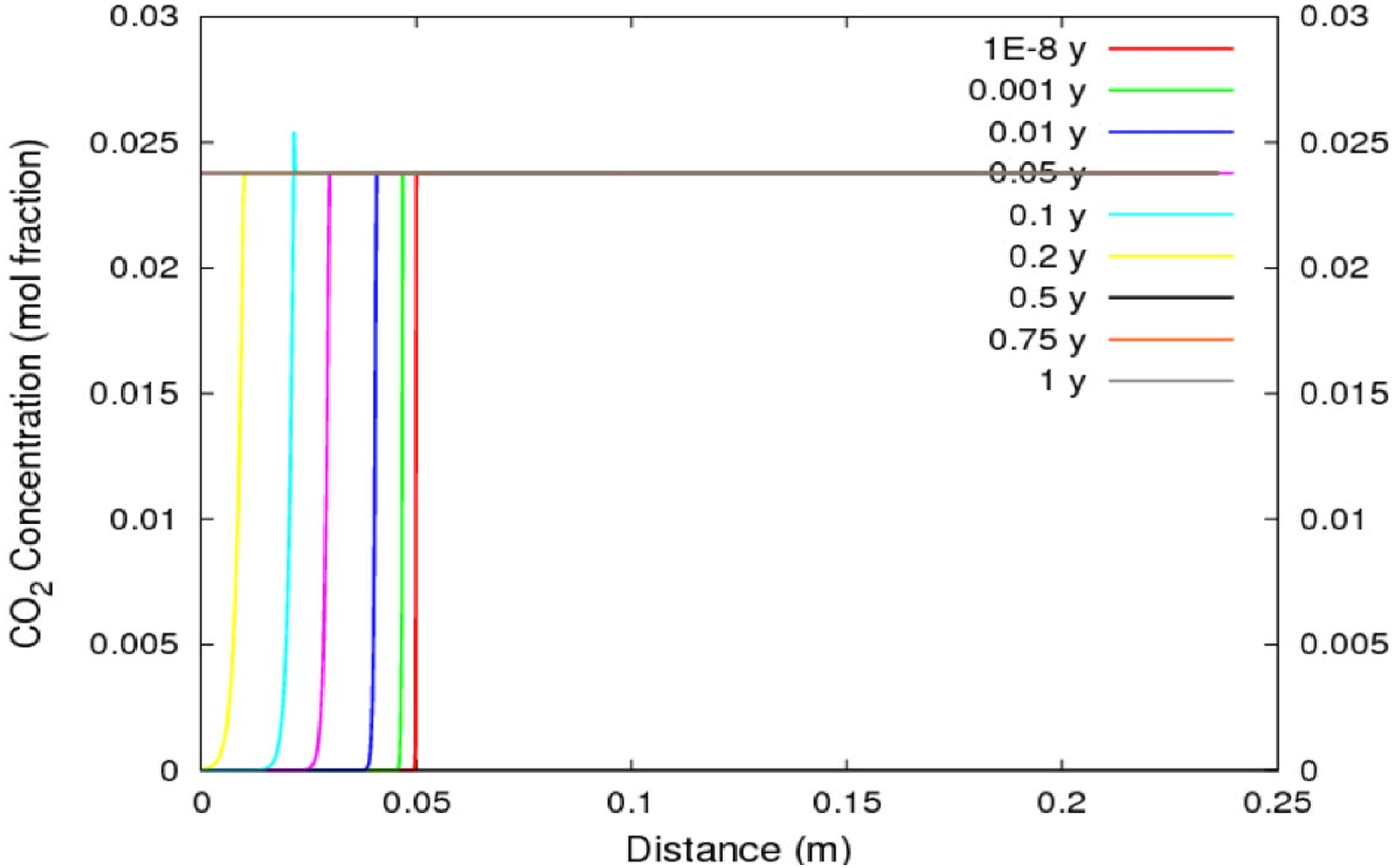


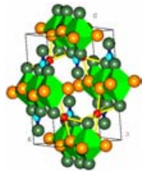
No Contrast: Cement-like Properties



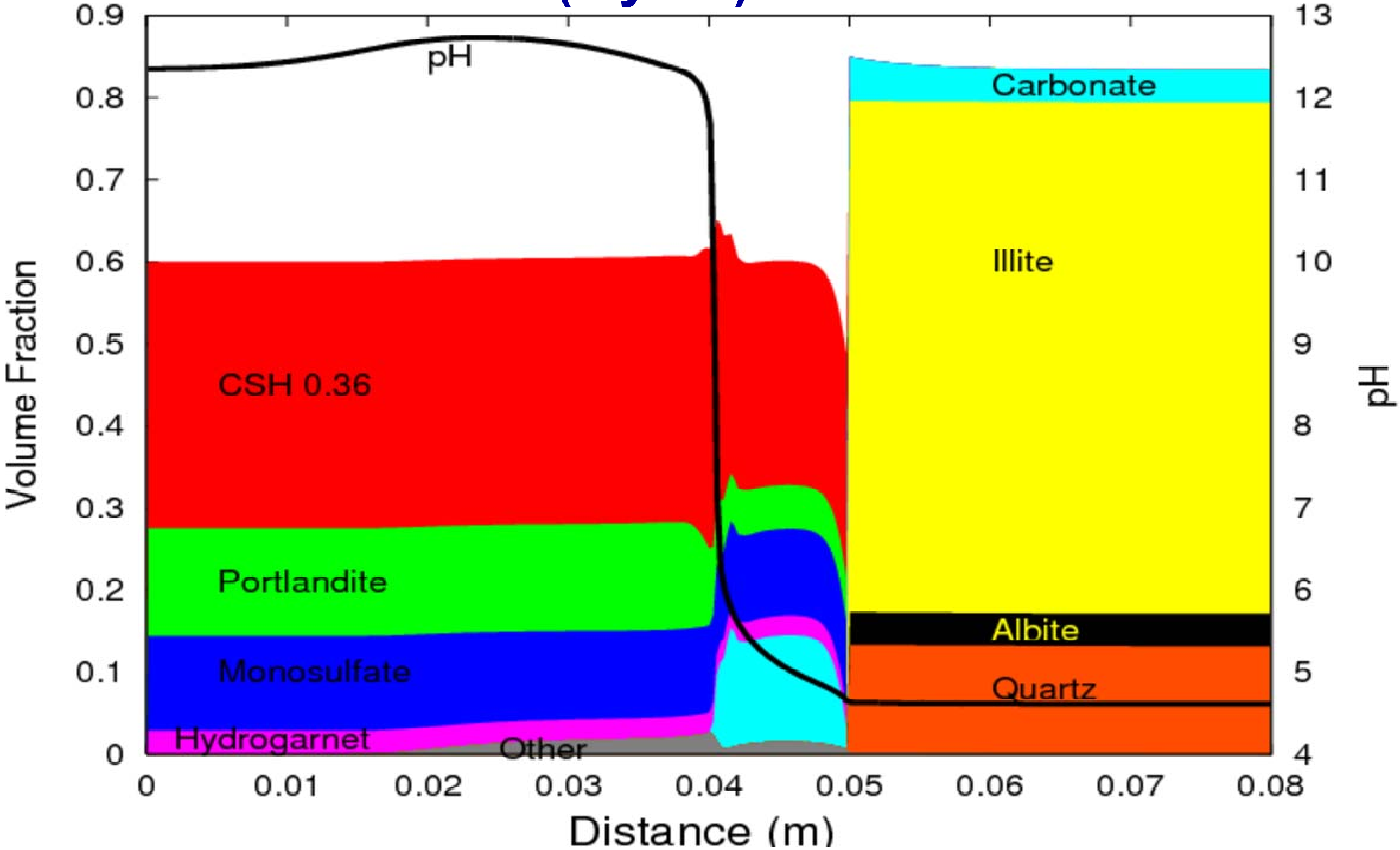


No Contrast: Cement-like Properties

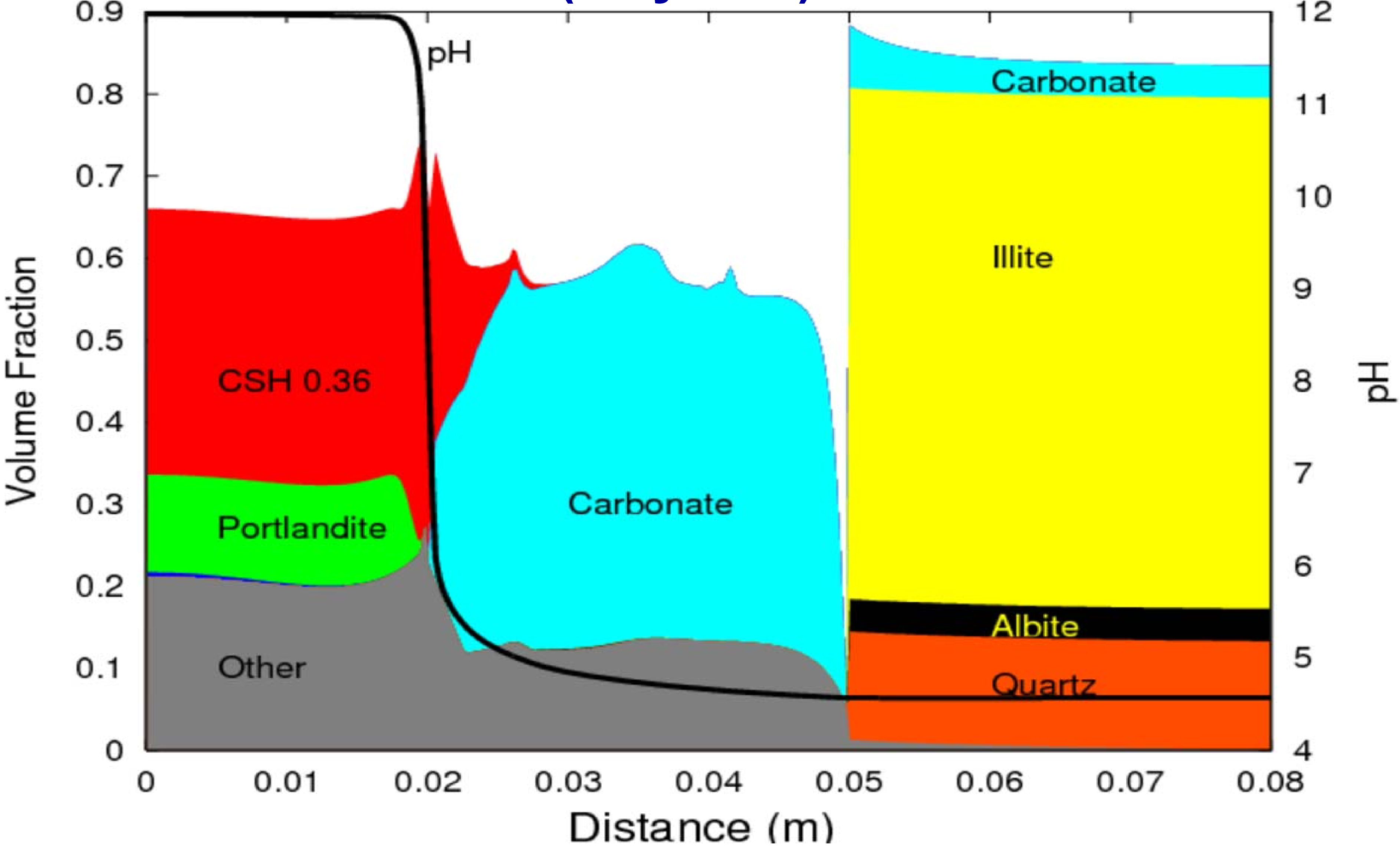




Cement: Reservoir (1 year)

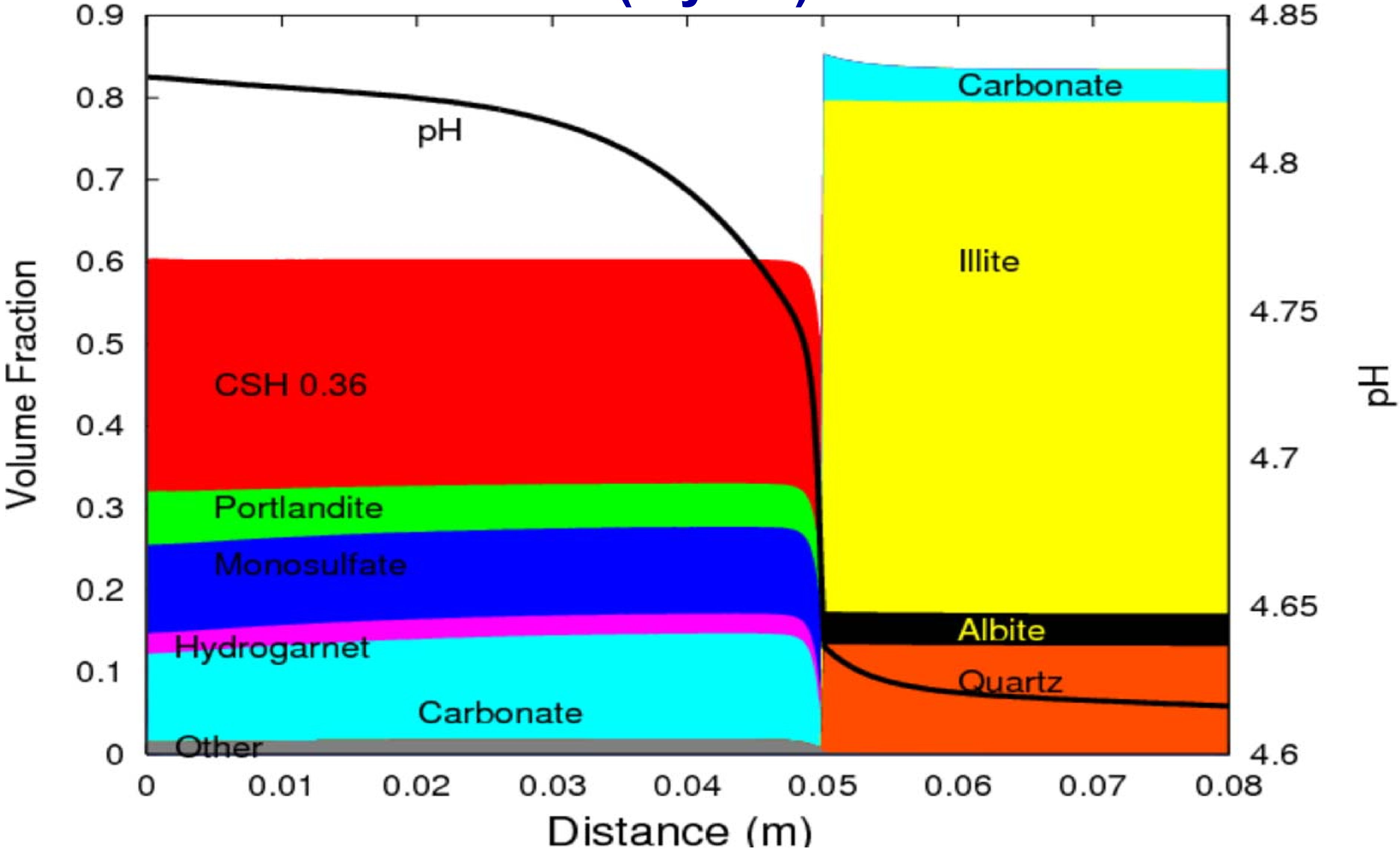


Cement: Reservoir (30 years)

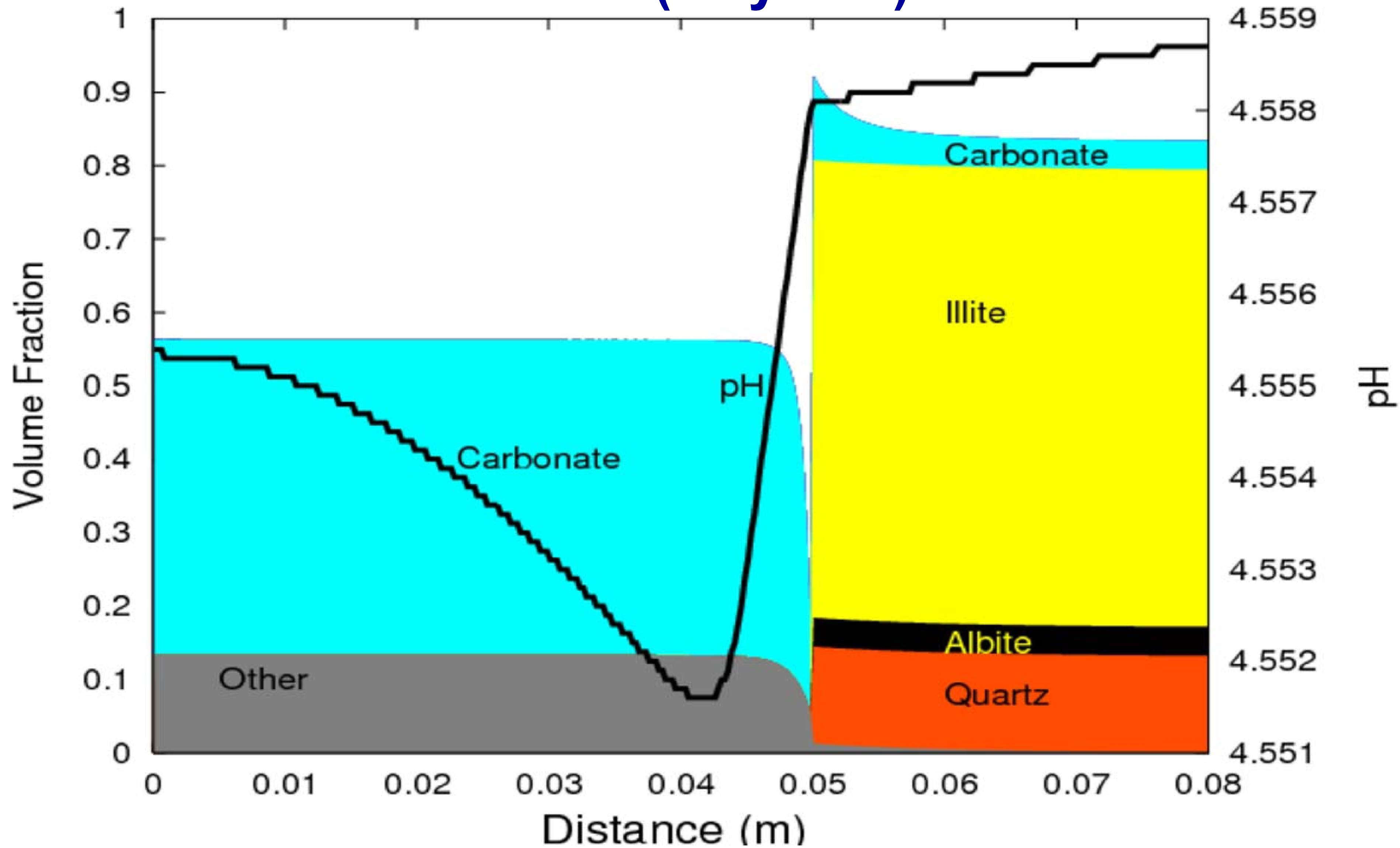


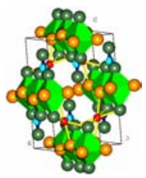
Los Alamos

Cement: Cement-like (1 year)



Cement: Cement-like (30 years)

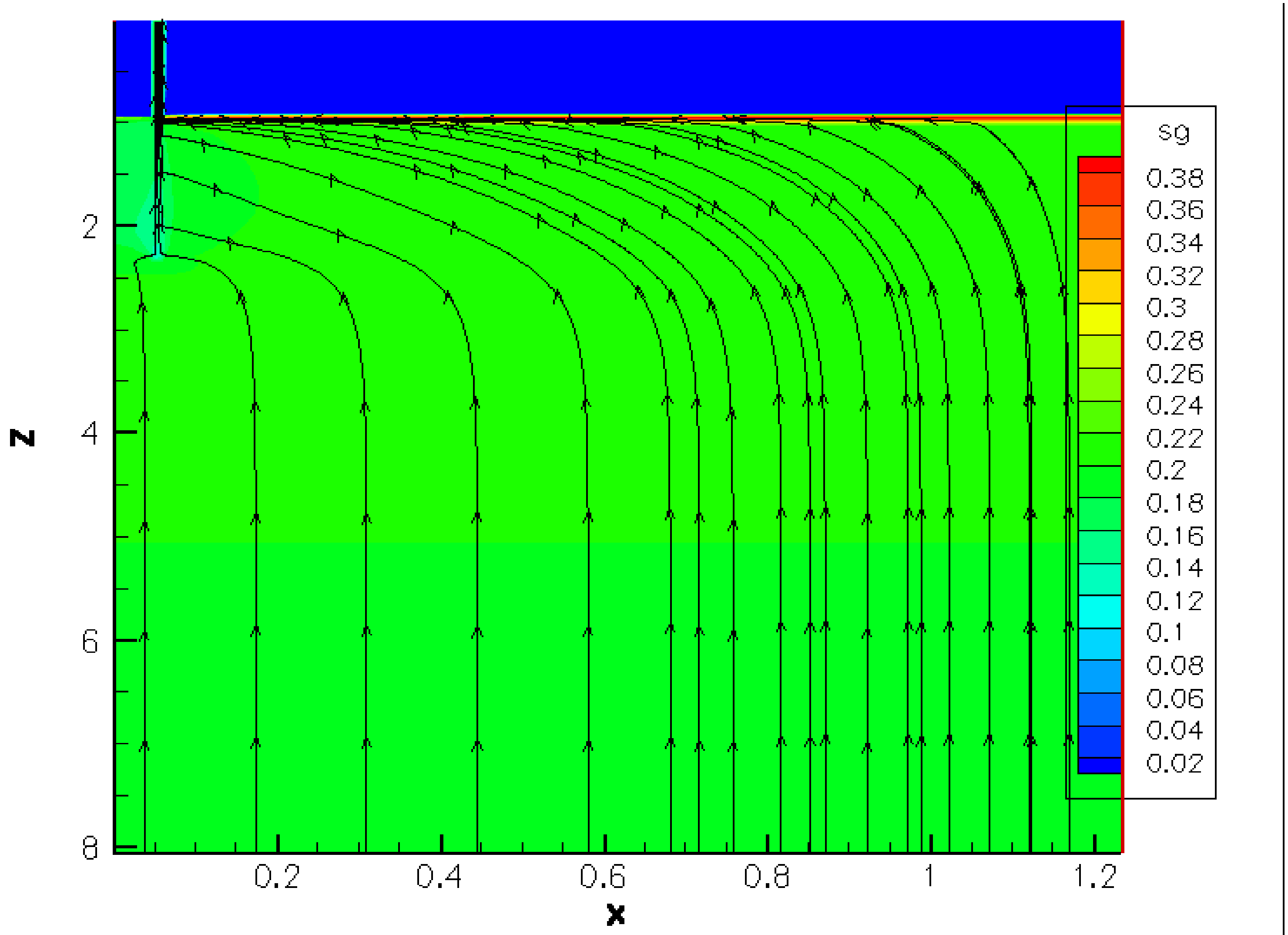




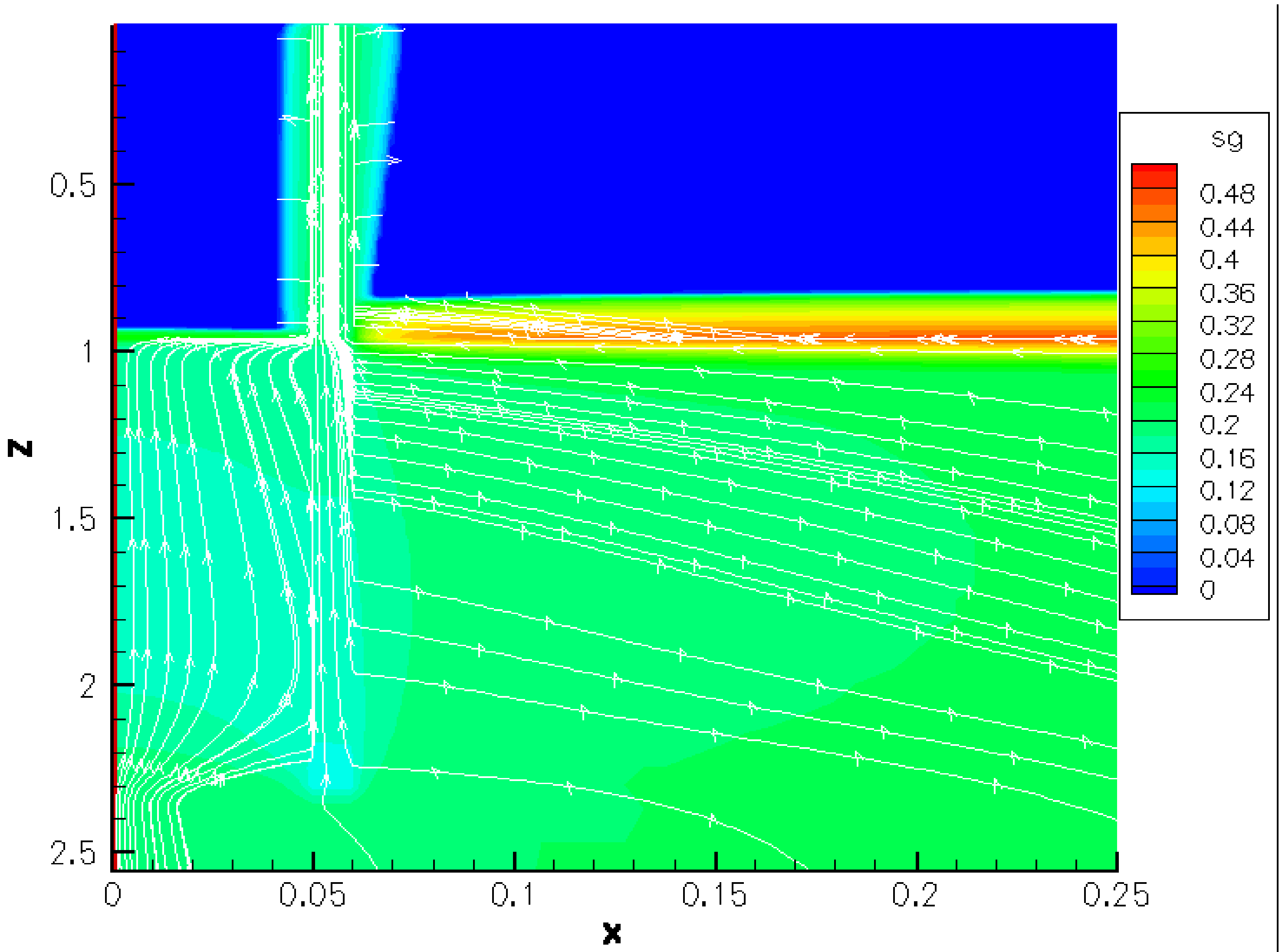
2-D, Two-Phase Wellbore Problem

- Narrow, high permeability zone at cement-caprock interface
- Cement and caprock have similar capillary pressure functions
- Buoyancy driven CO_2 movement (no pressure gradient)
- Minimum CO_2 plume thickness required to overcome capillary barrier
- Constant pressure along top and bottom boundaries (hydrostatic-like pressure gradient)

CO_2 saturation at 0.05 years

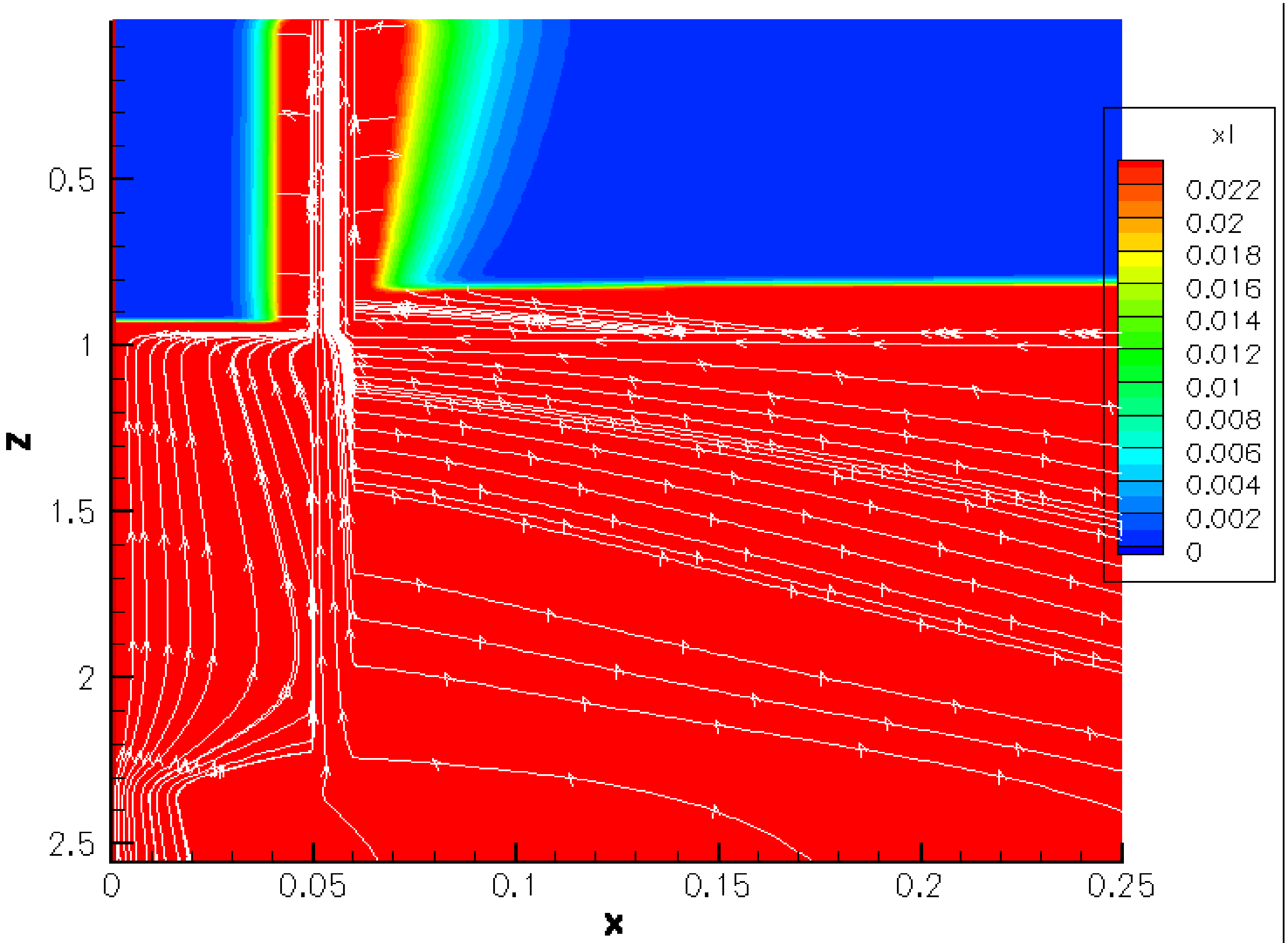


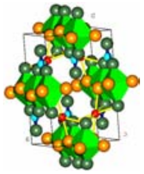
CO_2 saturation at 0.2 year



Los Alamos

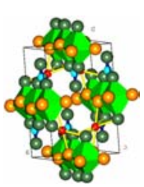
Dissolved CO_2 at 0.2 year





Conclusions

- Capillary pressure-driven drainage of cement can result in more rapid CO_2 penetration into cement
- Supercritical CO_2 along interfaces or other high porosity (low capillary pressure) contacts has low capillary driving force
- Capillary driven flow of CO_2 into high-quality cement unlikely
- High water/cement ratio promotes low capillary pressure properties and may allow capillary sorption of supercritical CO_2
- 2-D simulations allow investigation of interface flow dynamics; relative importance of drive by pressure gradient versus buoyant flow unclear



Measuring Effective Wellbore Permeability

Sarah Gasda, Princeton University
Michael Celia, Princeton University
Jan Nordbotten, Univ. of Bergen

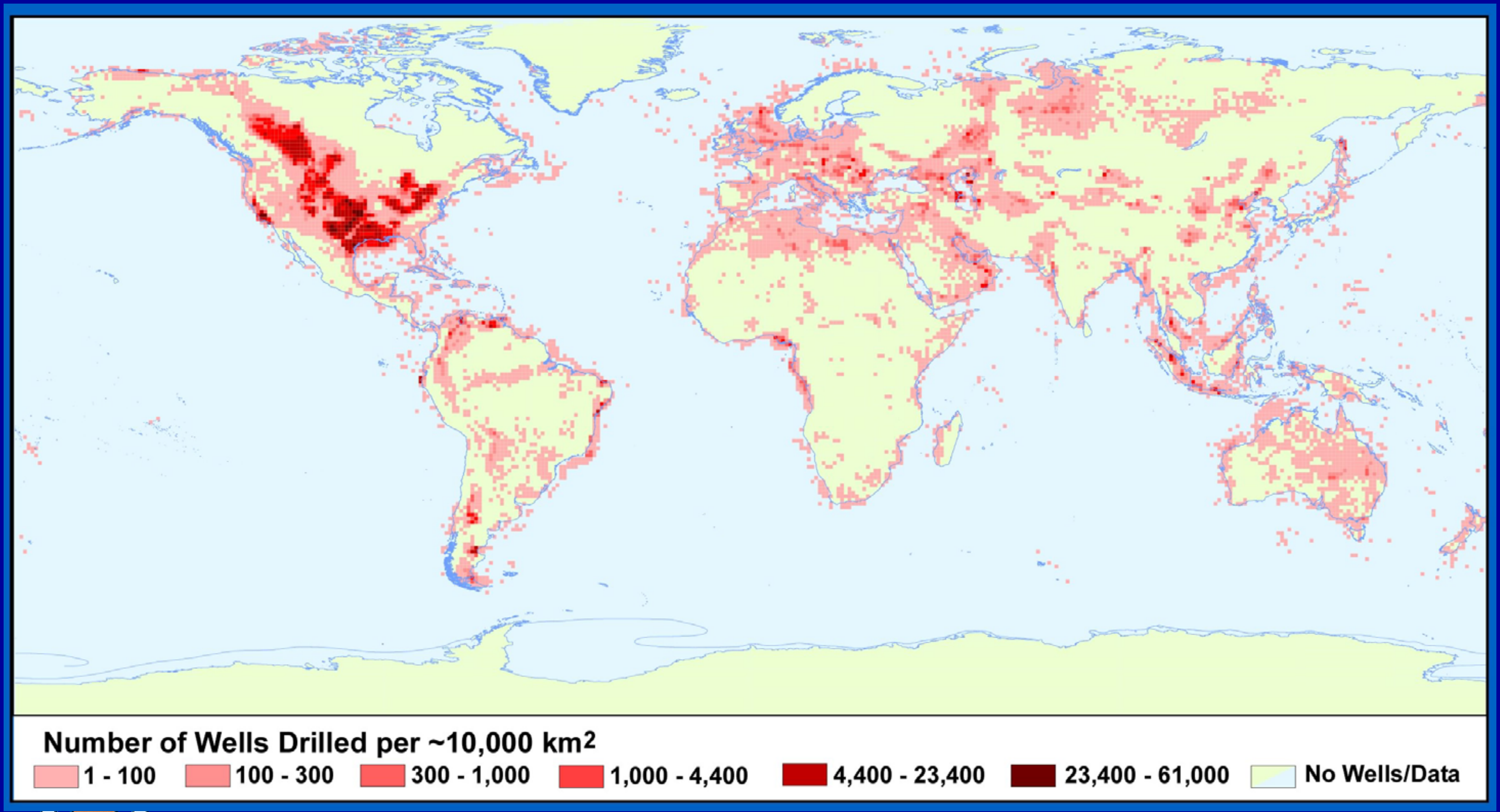
Objective

- Propose a simple field test to determine *effective* (*bulk*) wellbore permeability
- Use numerical analysis to determine the feasibility of this test
  - Define the range of detection given constraints on instrument accuracy

Approach

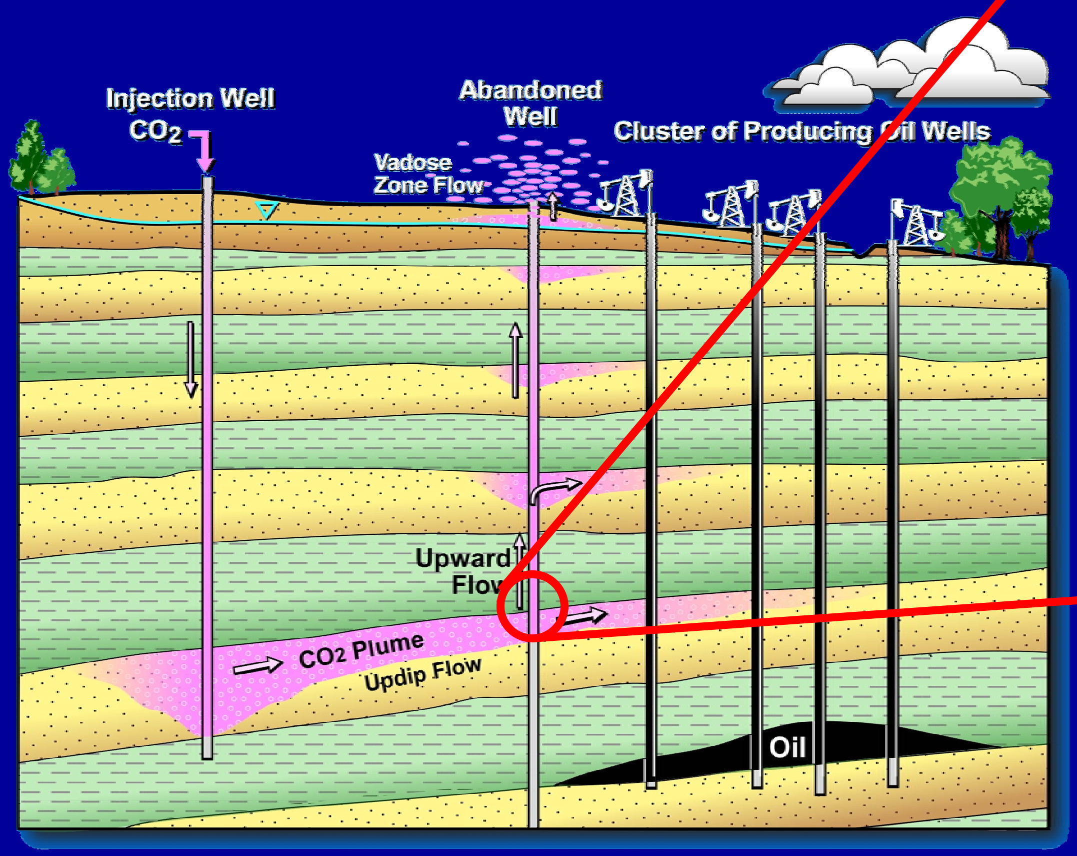
- We design a test to determine well permeability.
  - If we can estimate permeability values for the formation and caprock, we can find well permeability from pressure response.
- We do this by using simulations to generate response curves that relate pressure response to well permeability.

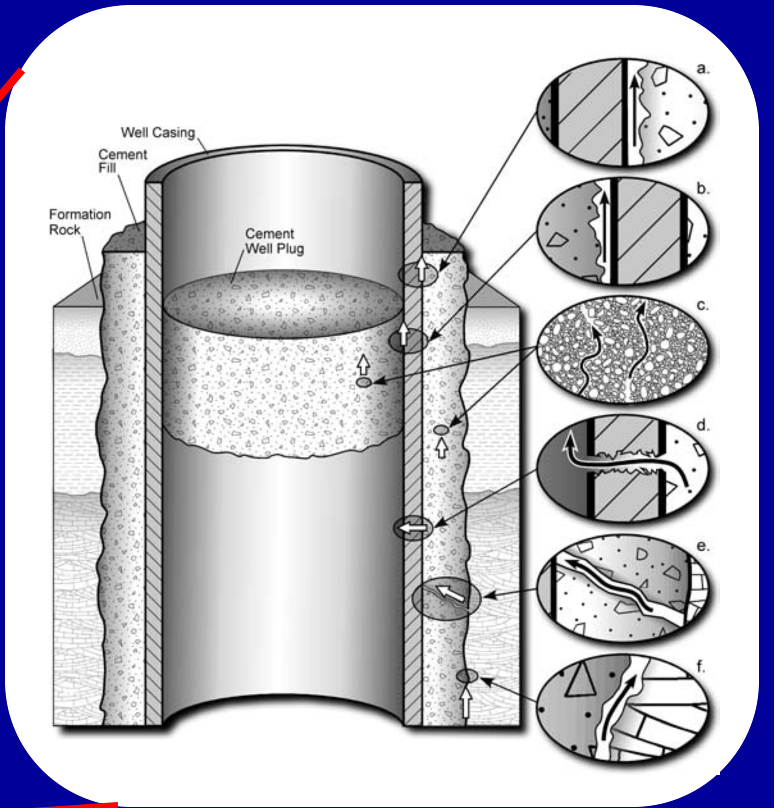
Existing Oil and Gas Wells



From IPCC SRCCS, 2005

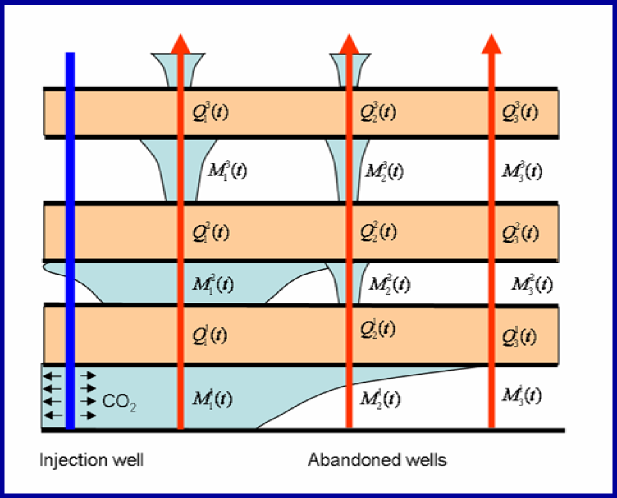
Leakage Pathways in Wells

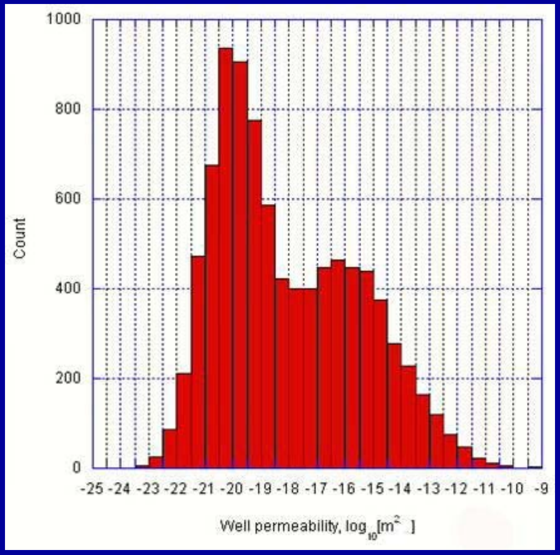




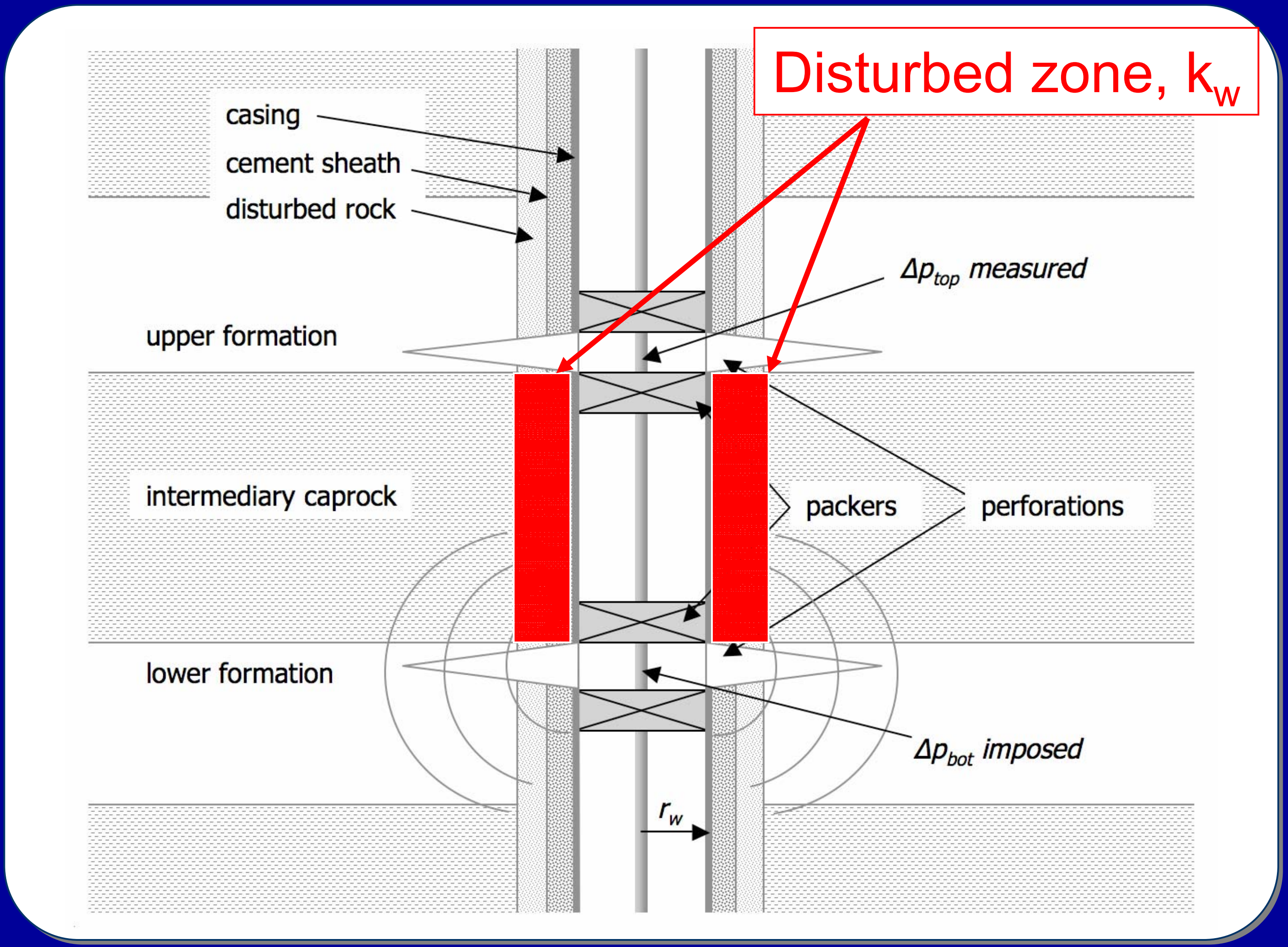
Modeling CO_2 leakage

- **Large spatial and temporal scales**
- **Multiple leaky wells**
  - **probabilistic framework**
- **No data exist on wells**
  - **Need to pin down statistical distributions**
- **Need a simple test to identify k_{well} in well segments**



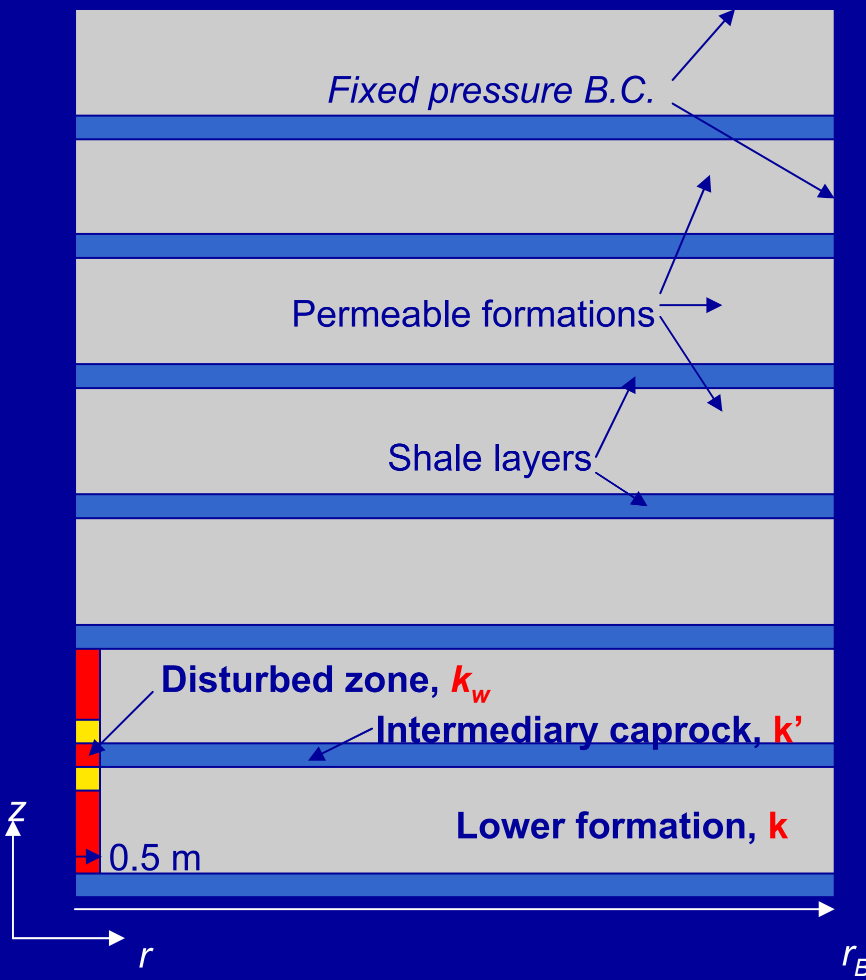


Experimental Design

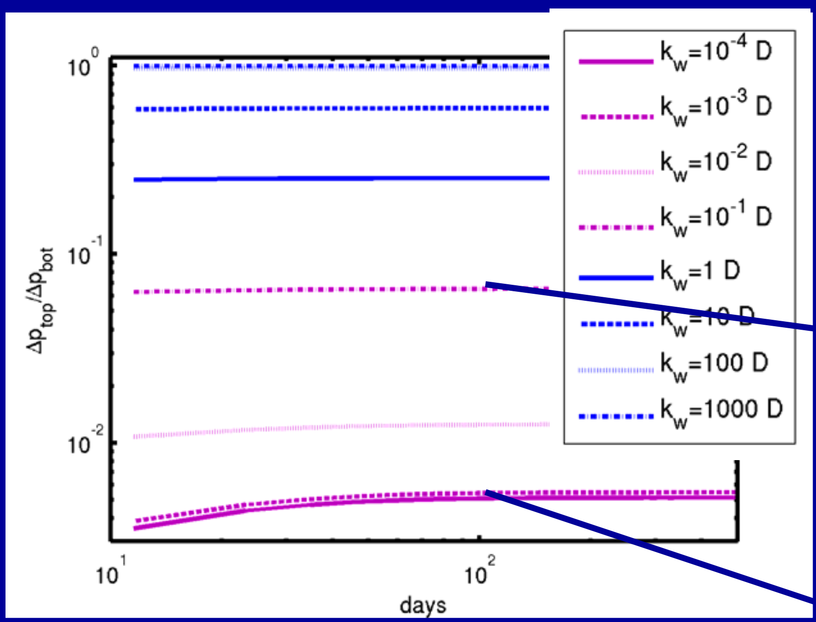


Numerical Experiments

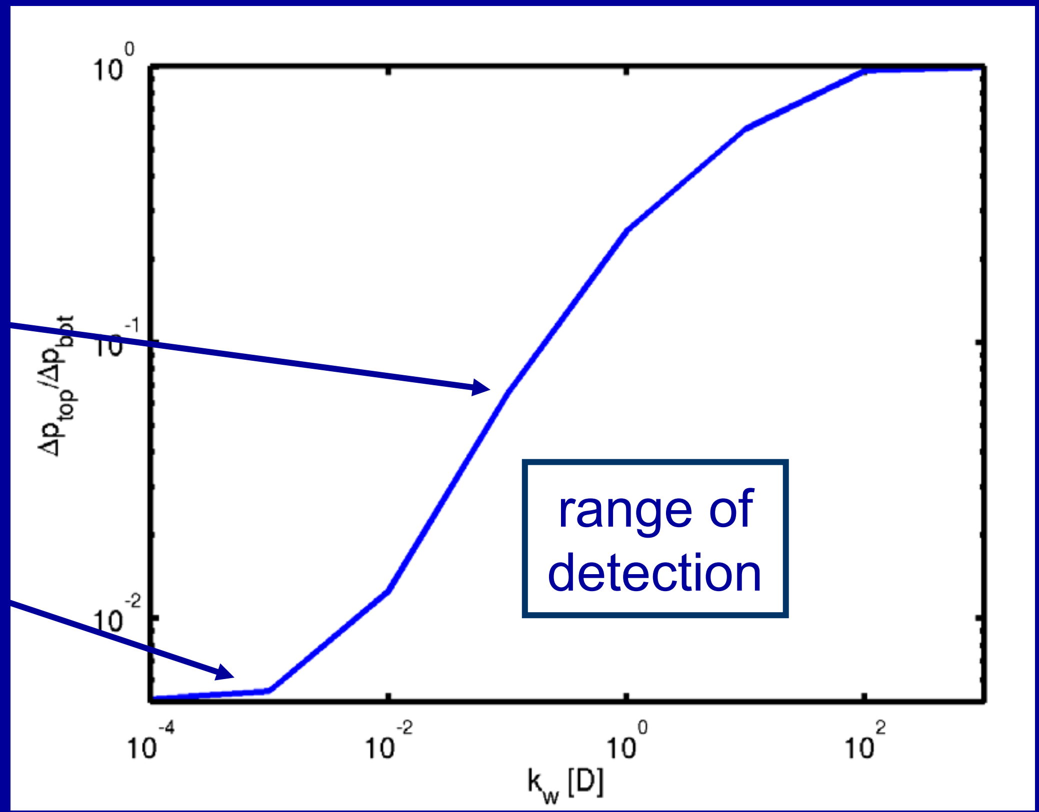
- Standard finite-difference simulator
  - axi-symmetric coordinates
  - transient, single-phase flow
- 7 permeable layers (10mD), 7 shale caprocks (0.1mD)
  - Fixed pressure at top and outer boundaries
  - Impermeable bottom boundary
- Explore parameter space
  - Vary permeability in well (k_w), caprock (k’), and lower formation (k)



Example Numerical Results

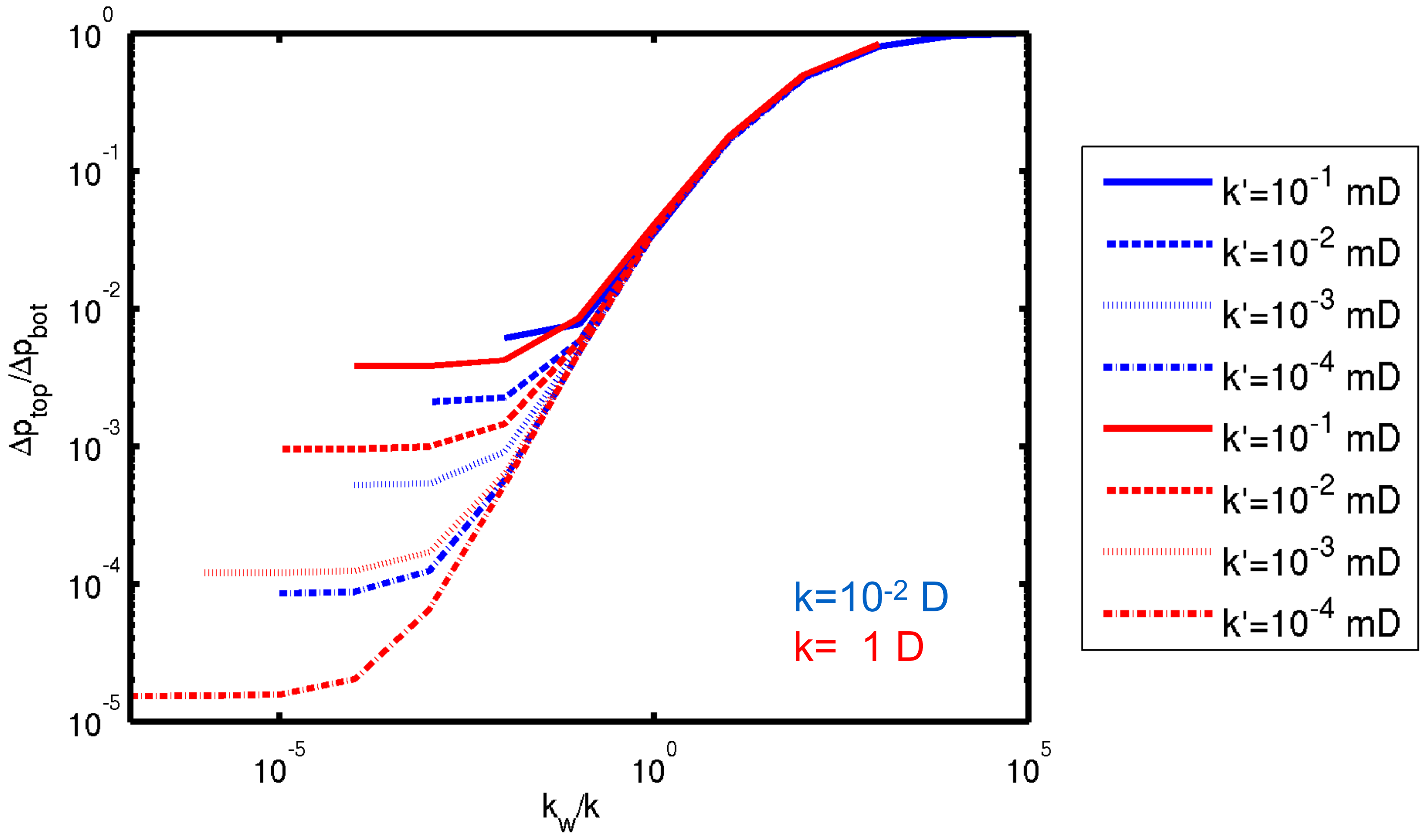


Transient data



Steady-state data

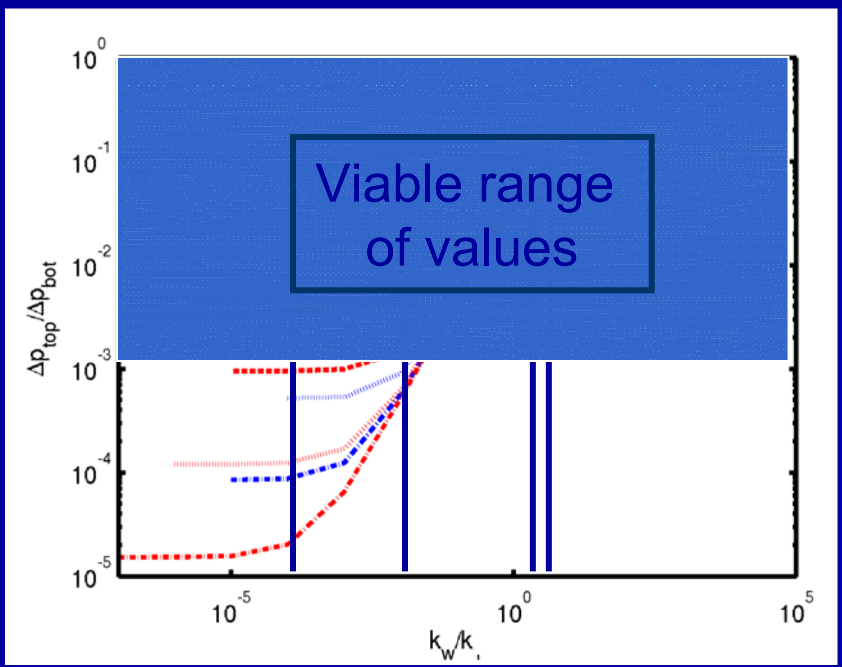
Dimensionless Results



Limits on Field Measurements

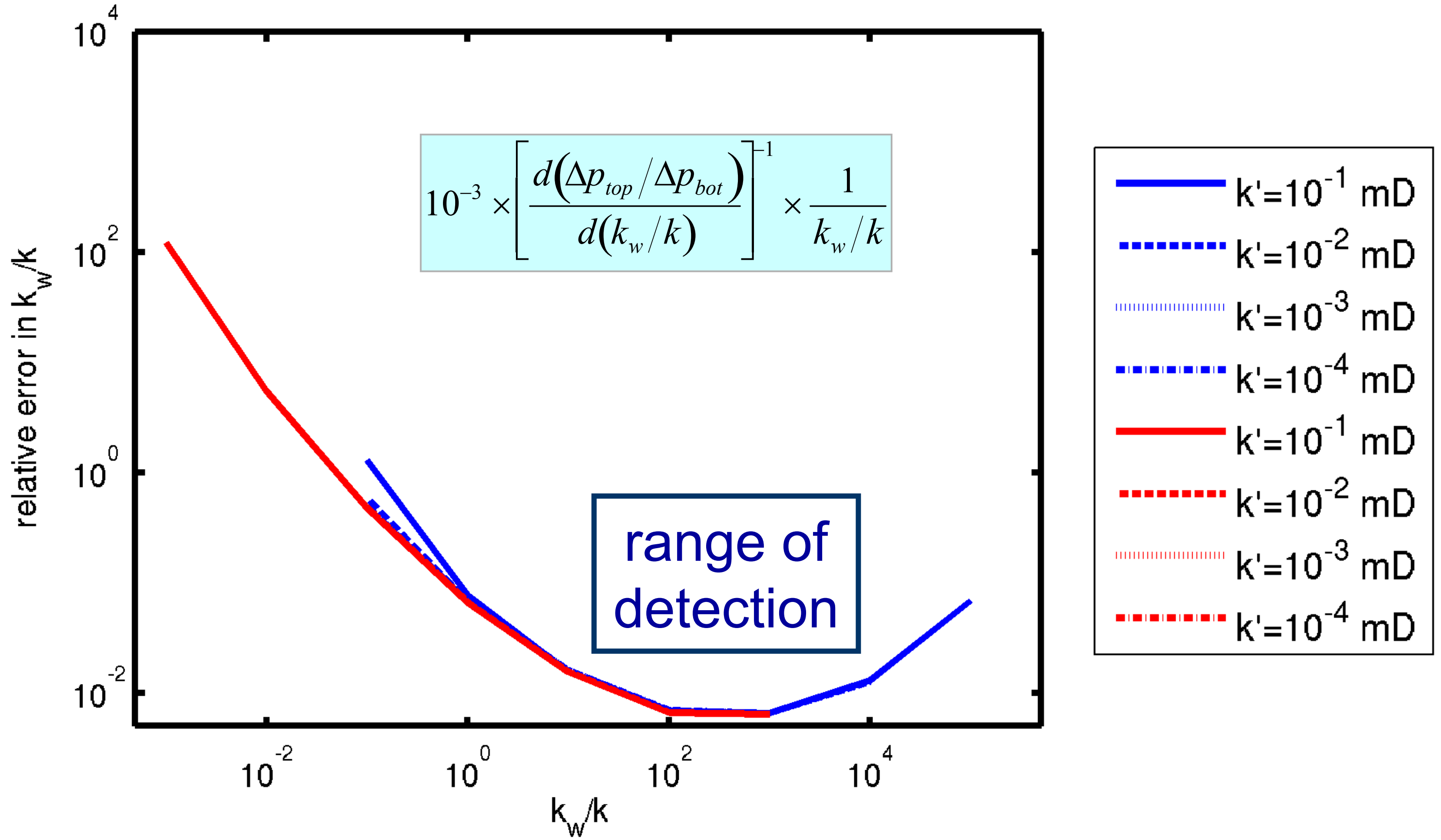
- Instrument measurement accuracy
  - Pressure transducers rated for high P,T
    - ±0.1 bar (Schlumberger, UNIGAGE Quartz)
- Fracture pressure
  - Minimum horizontal fracture stress ~17 kPa/m
    - Bachu et al. 2005. *Underground Injection Sci. & Tech.*
  - Maximum pressure change must be less than fracture pressure minus initial pressure
    - Average hydrostatic gradient ~11kPa/m
- Order-of magnitude sensitivity limits
  - *Error in* $\Delta p_{top} = \pm 10^{-2}$ MPa, $\Delta p_{bot} \leq 10$ MPa

Estimation of Sensitivity Limits



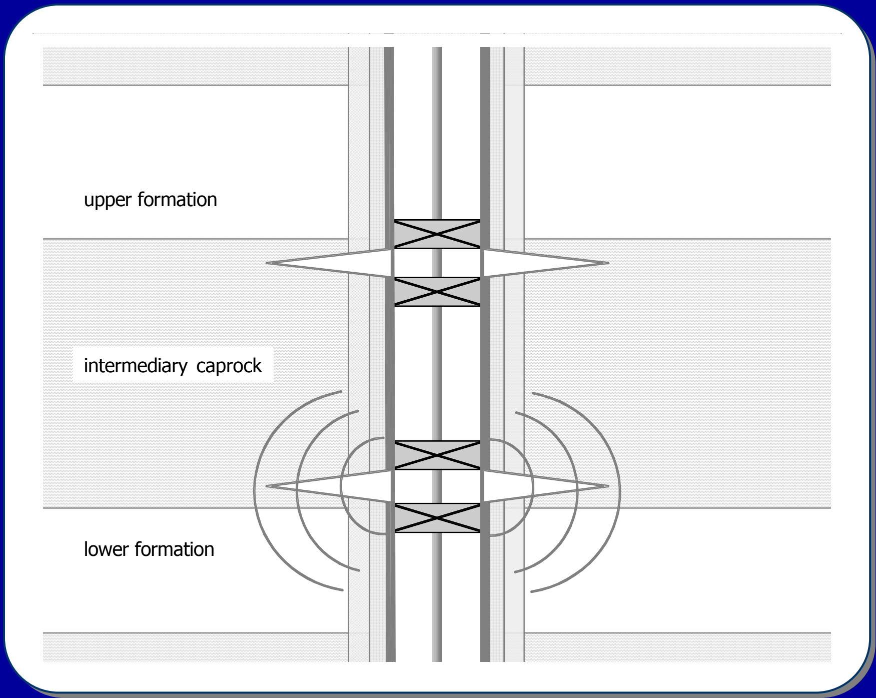
- *Error in field data*
  - $\Delta p_{top}/\Delta p_{bot} = \pm 10^{-3}$
- *Viable range of values*
  - minimum pressure that can be measured reliably
- *Insensitive response regions*
  - Slope of curve is flat
  - Small error in Δp_{top} translates to large uncertainty in k_w

Range of Detection

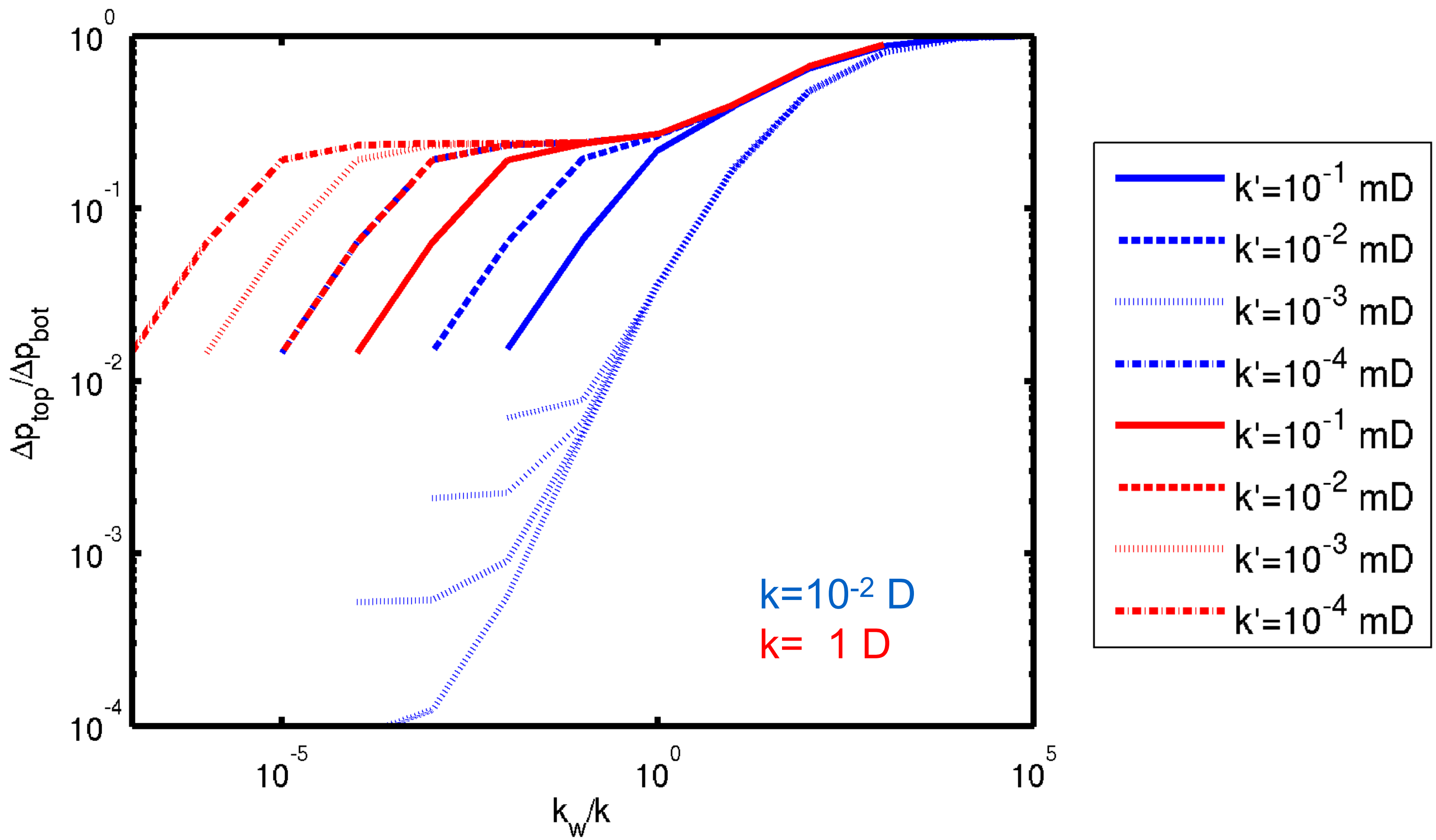


Alternative Test Design

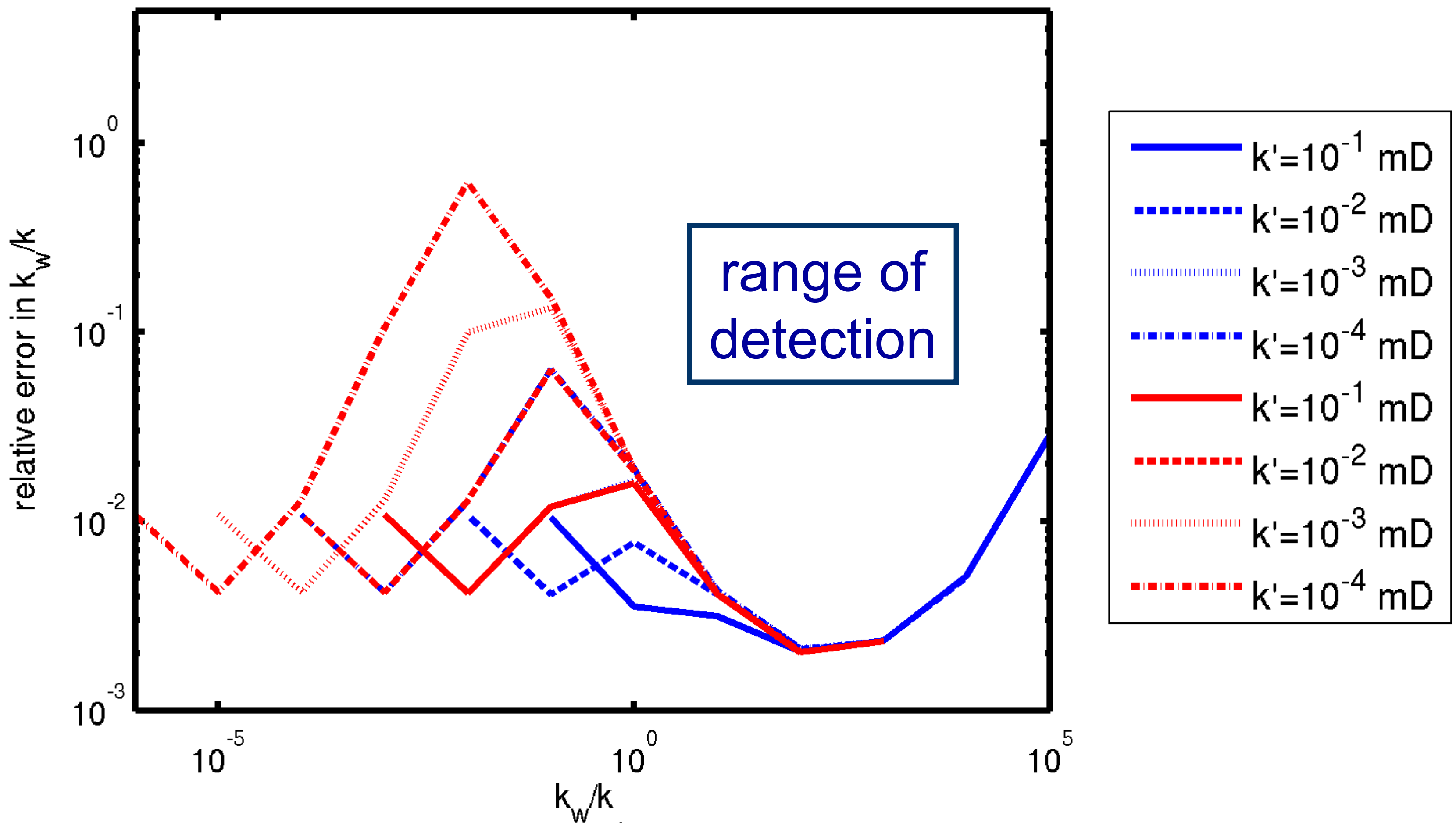
- Purpose
  - Reduce influence of lower formation permeability on pressure response
  - Expand range of detection
- Move perforations to location within intermediary caprock
- Repeat numerical experiments



Modified Test Results



Improved Range of Detection



Conclusion

- There is a lack of meaningful data available for well properties.
- A simple downhole pressure test can identify effective well permeability values that are in the critical range of values.
- Field experiments are needed to reduce the uncertainty associated with current estimates of CO_2 leakage.

Thank you!

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Assessing wellbore leakage and its potential impact with CO_2-PENS

Rajesh J. Pawar

Los Alamos National Laboratory

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Co-authors

- Phil Stauffer
- Hari Viswanathan
- Dmitri Kavetski (Princeton)
- Thomas McTighe
- Seth Olsen
- James Carey
- Julianna Fessenden
- John Kaszuba
- Gordon Keating
- Peter Lichtner
- Marcus Wigand
- George Zyvoloski
- George Guthrie

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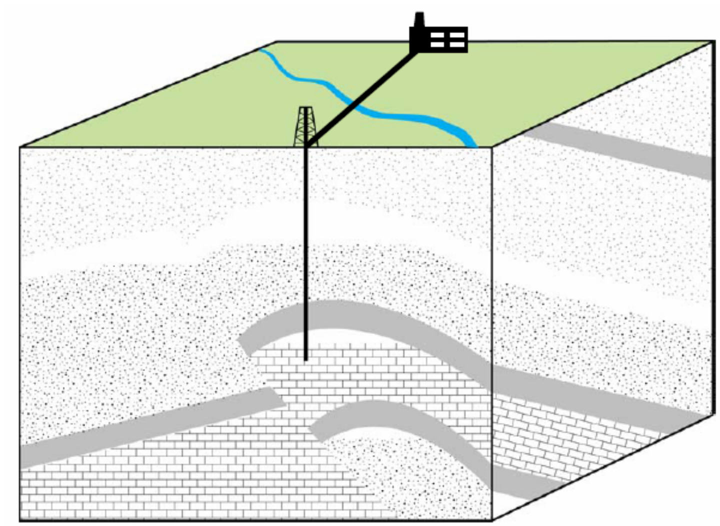
Quantitative Risk Assessment for Long-Term Storage of CO_2 in Engineered Geologic Systems



- **Risks to consider in CO_2 storage**
  - Economic-environmental-health
  - Short-term vs. long-term
- **Science based prediction for risk assessment**
  - Integration of field observations with theory-experiment-computation
  - Uncertainty and heterogeneity in natural systems
- **Integrity of cemented wellbores**
  - CO_2+brine is acidic, cement is basic
  - Long-term fate of cement
  - Migration of CO_2 through cement

Risk Assessment: Some Definitions

- **Features/Events/Processes (FEPs) Analysis**
  - Systematic development of all possible features/events/processes controlling the performance of any natural system
- **Performance Assessment (PA)**
  - Estimates probability of a system exceeding certain performance metric
  - Does not address risk directly
  - Can be difficult to determine what parameters control the system
- **Quantitative Risk Assessment (QRA)**
  - Combines performance assessment with consequence analysis
  - Quantifies effect of inherent uncertainties in natural system
  - Allows for decomposition of results into their important contributors

Risk = Event Probability x Event Consequence

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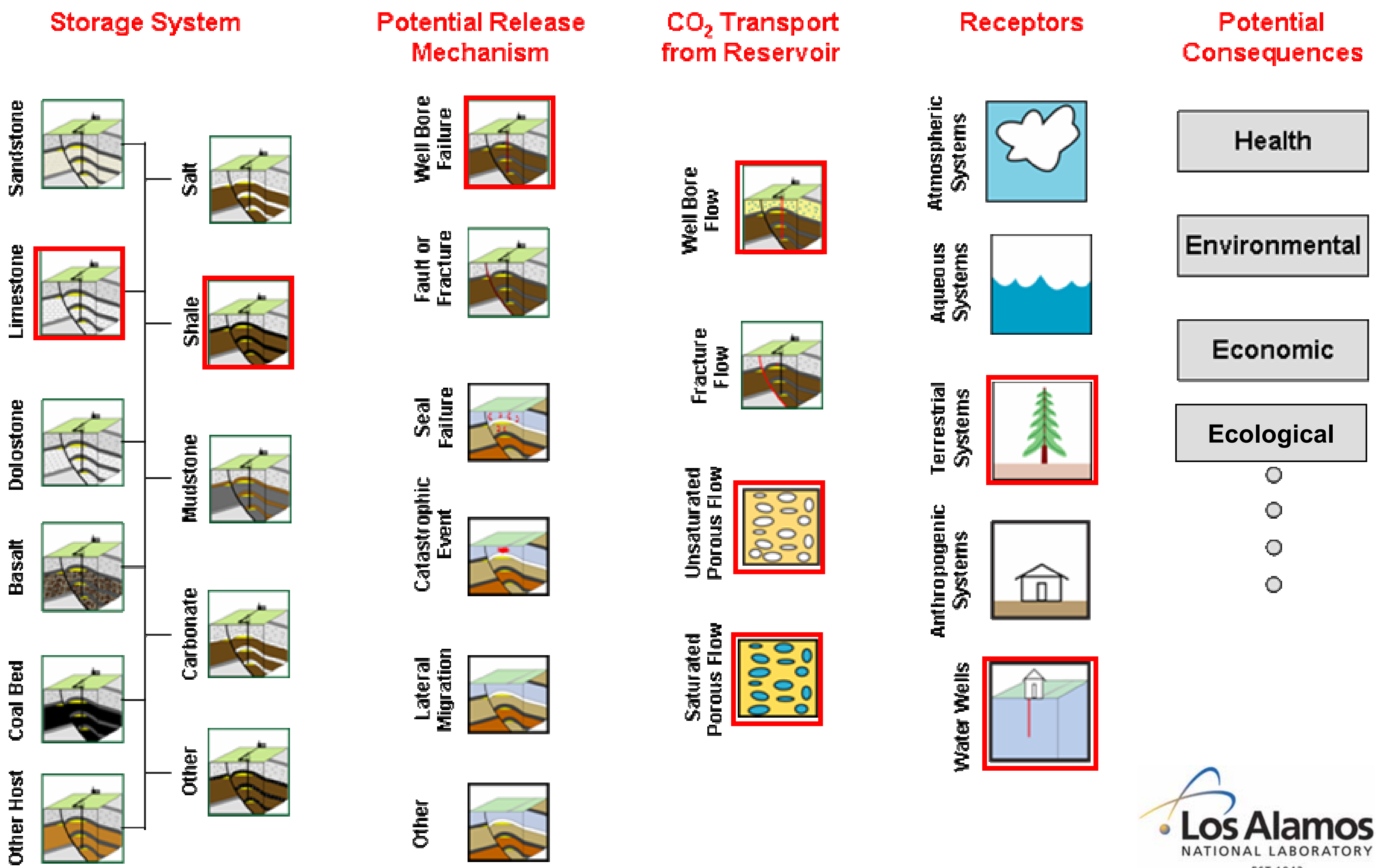
A comprehensive system framework can enable the development of Master Logic Diagrams (MLDs) commonly used in QRAs



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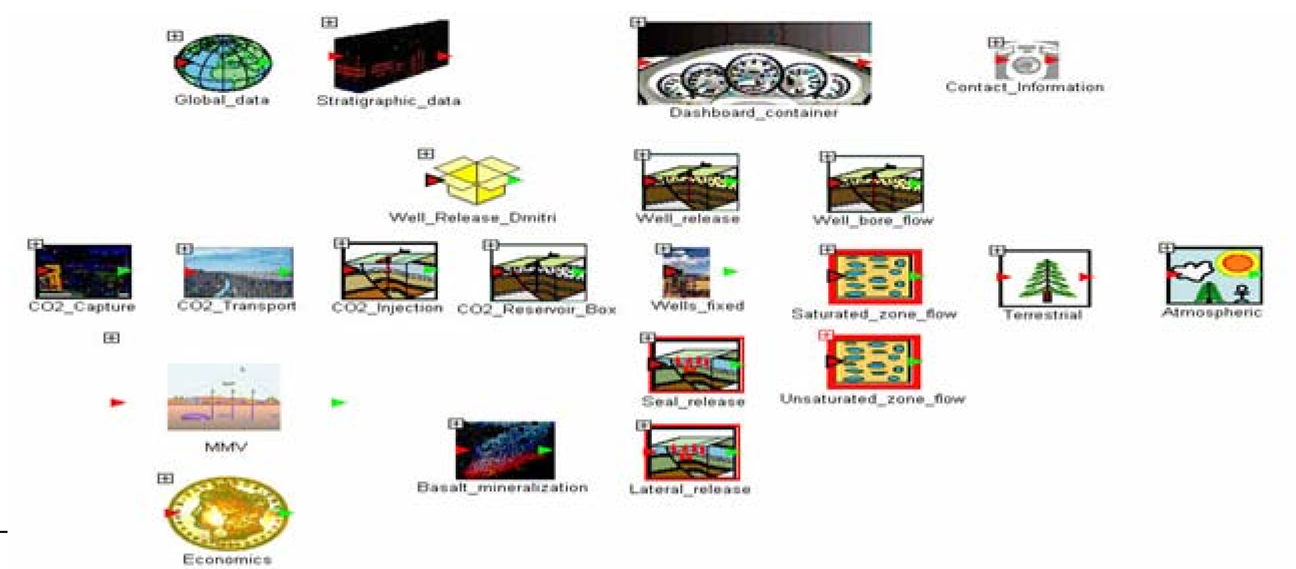
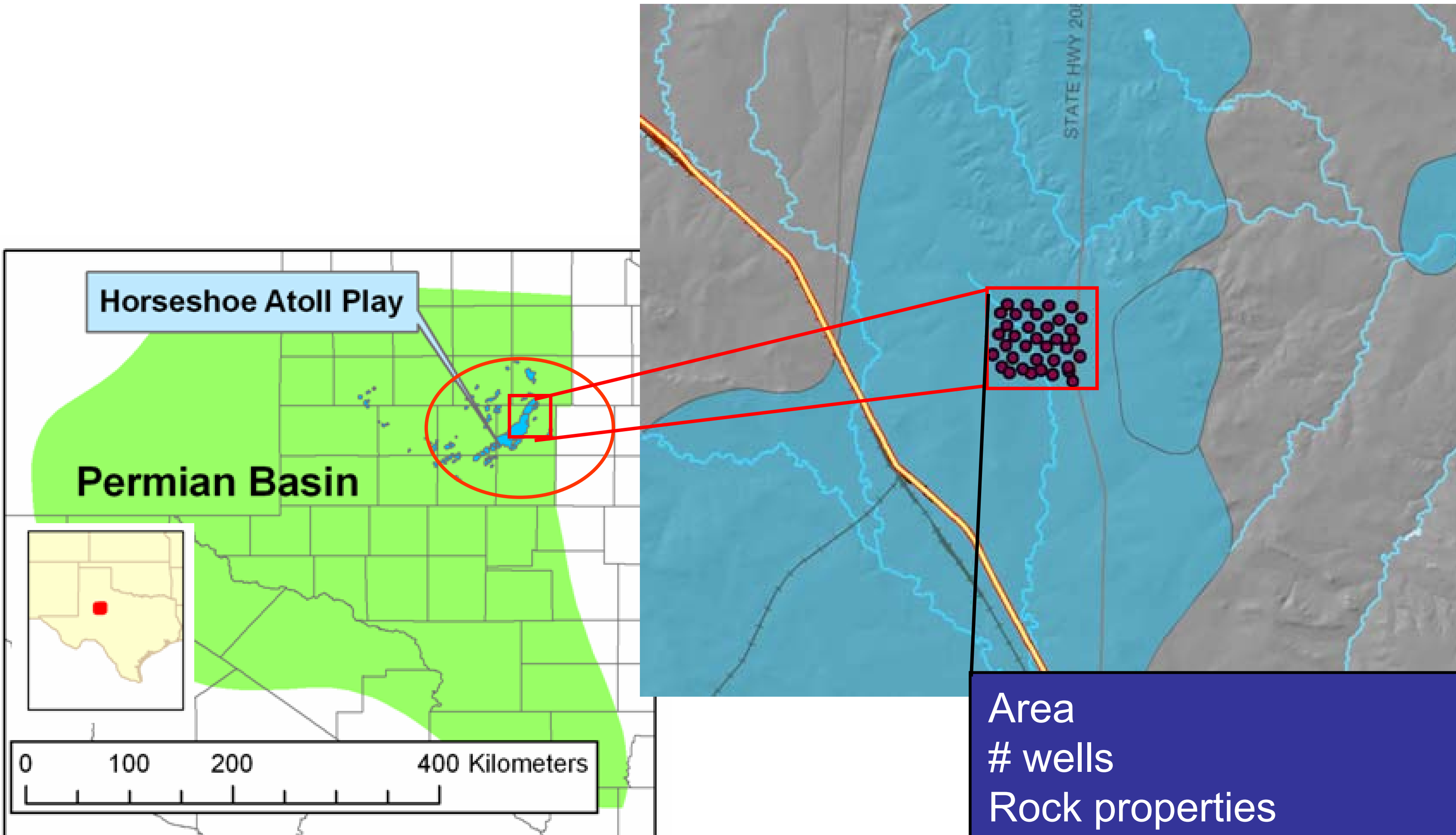
Comprehensive assessment of sequestration operation with CO_2-PENS

- **CO_2-PENS is a modular, systems level model being developed to perform comprehensive analysis of CO_2 sequestration sites**
  - Simulate CO_2 transport & migration from sources to storage & beyond.
  - Supports a science based quantitative risk assessment.
  - Integrates modules that are governed by different physics and are described by analytical/semi-analytical/detailed numerical models.
  - Can be used to assess & certify specific storage sites.
  - Can be used to tailor MMV & engineering options to specific sites.



GIS tools are being developed to link to databases and to import necessary data



- Area
- # wells
- Rock properties
- Wellbore properties
- Surface conditions
- Ground-water wells

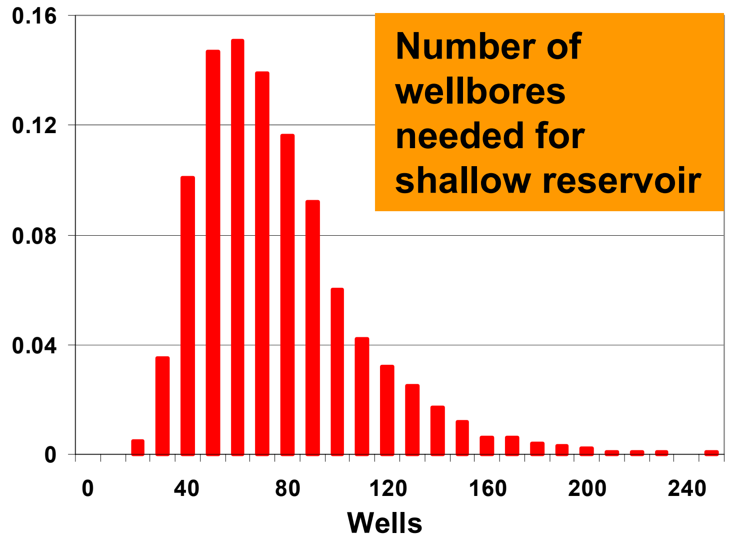
Reservoir performance calculations are performed through analytical models or detailed process models

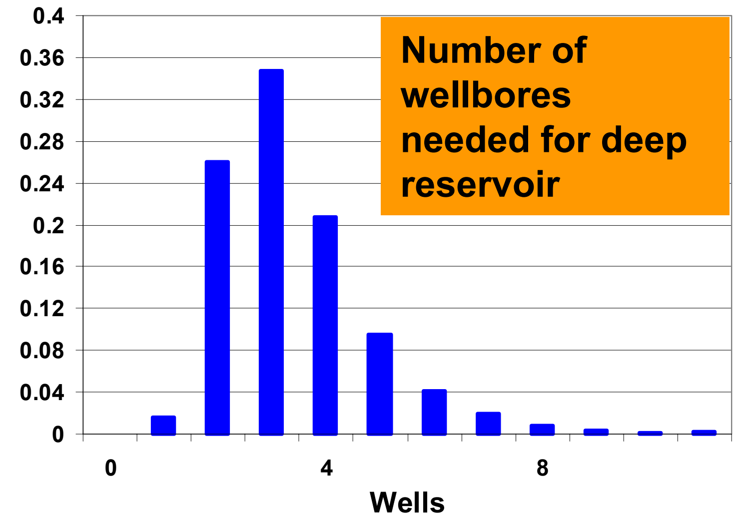
- **Analytical solution**
  - 2-phase injection analytical solution: van Everdingen & Hurst, 1949; Nordbotten et al. 2005
  - Fortran module coupled as a DLL
- **FEHM 3D continuum scale simulation**
  - Control volume, finite element
  - Multiphase flow; coupled reaction & flow (heat/mass)
  - Full scale reservoir simulator coupled as DLL
- **Flexibility in reservoir management schemes**
  - Only injectors
  - Injectors & producers: accounts for produced water

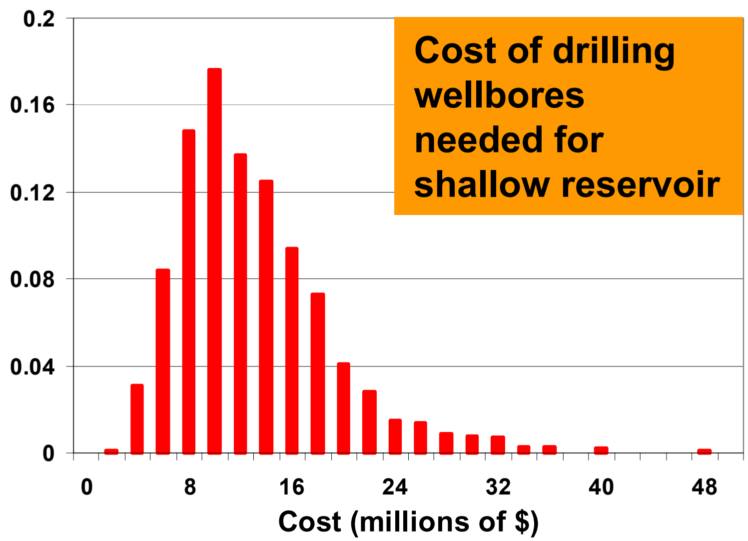
Economic assessment: an example

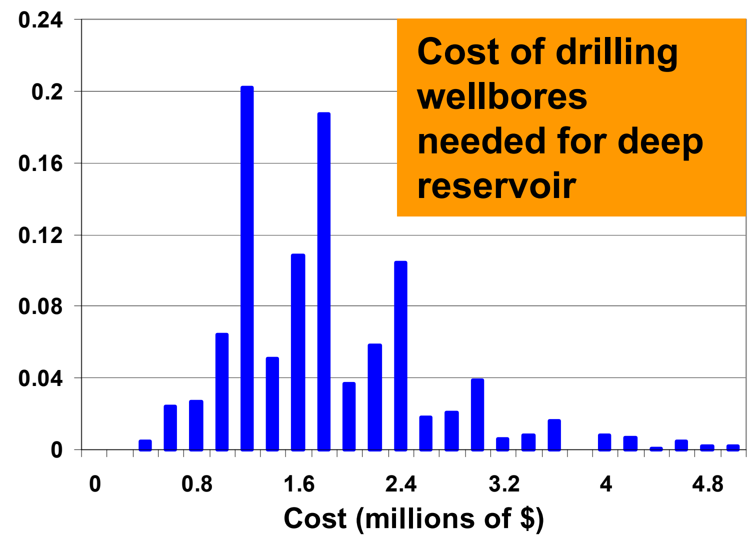
- **A hypothetical reservoir**
  - Constant reservoir thickness, area
  - Distribution of reservoir porosity & permeability
  - Two cases: shallow reservoir (1 km), deeper reservoir (3 km)
    - Depth dependent pressure, temperature, fluid properties
- **CO_2 output from a 1000 MW coal fired power plant**
- **Injection calculations performed using analytical models.**
- **1000 realizations, each simulating 50 year injection**

Example Results

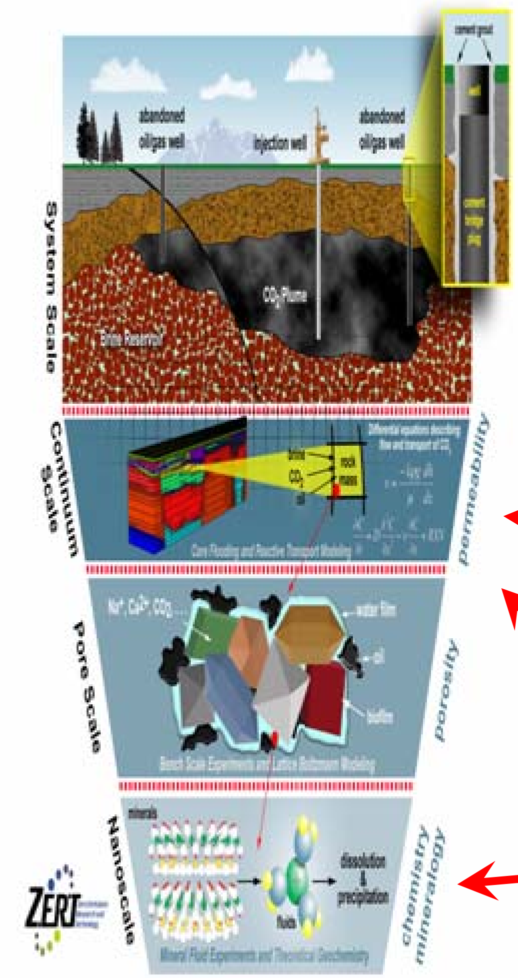


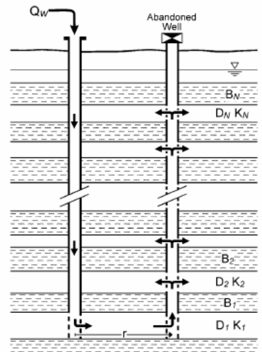




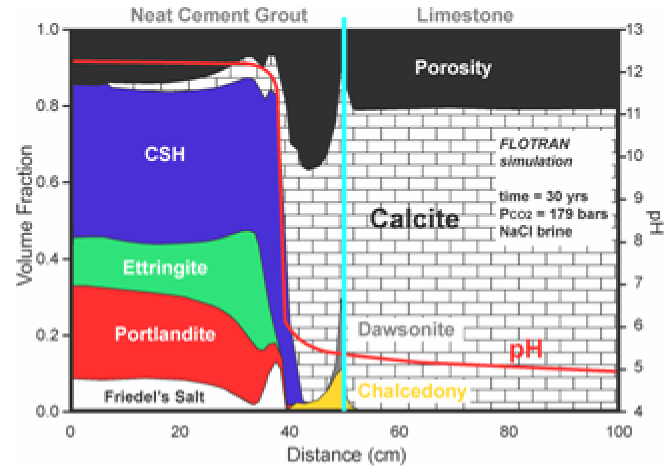


Predicting cement degradation and CO_2 release requires integration of theory, experiment, and observations from field to develop accurate computational models.





Semi-analytical model
for wellbore release
(working with Princeton CMI)



reactive-transport model to predict reactions and rates (Lichtner, Carey et al.)

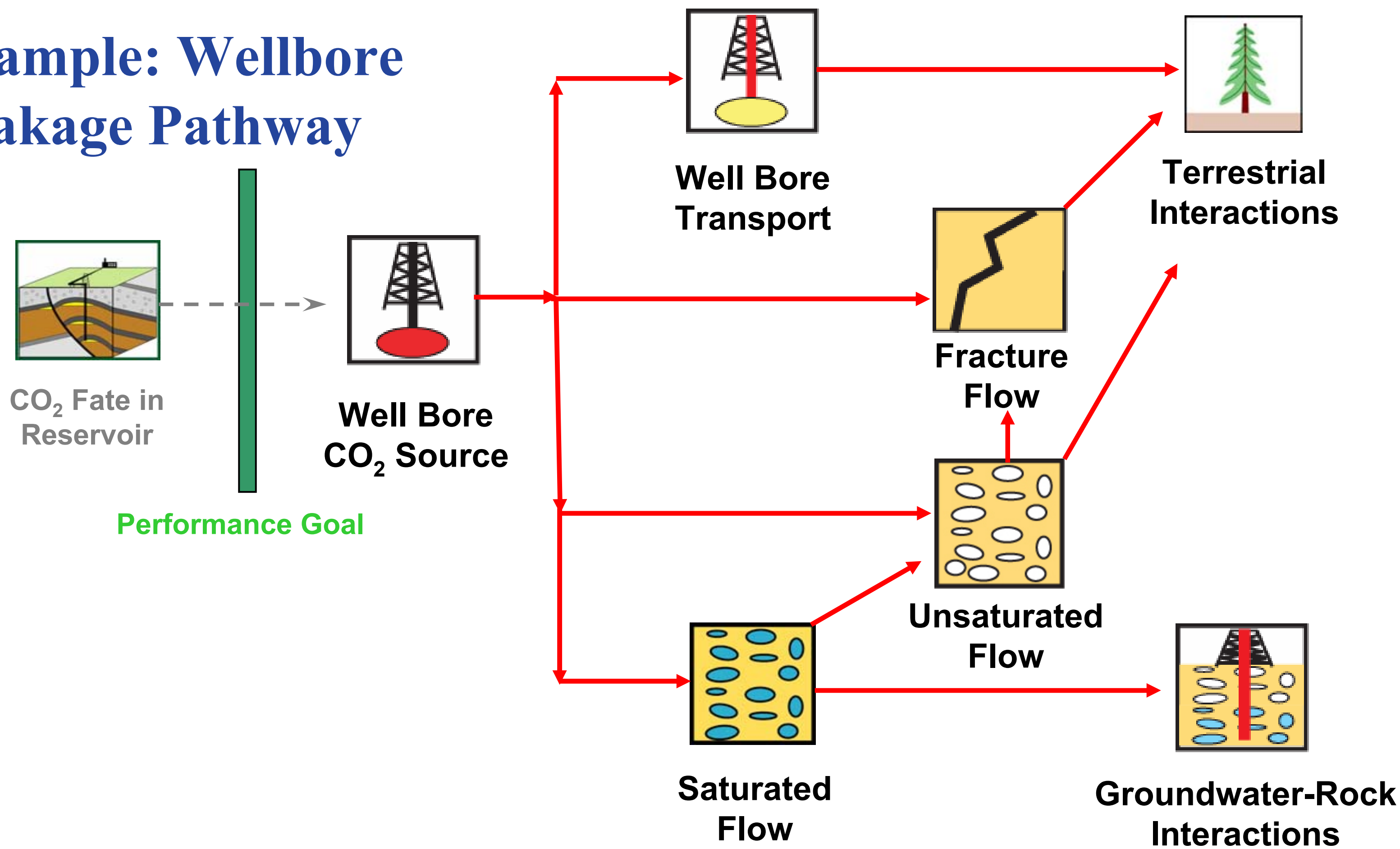
EOR (SACROC)

experiment (M. Wigand, LANL)

observations and experiments to determine reactions, rates, & impact

Need to predict probability of wellbore failure as well as migration of CO_2 subsequent to release, to understand the impact of wellbore failure

Example: Wellbore Leakage Pathway



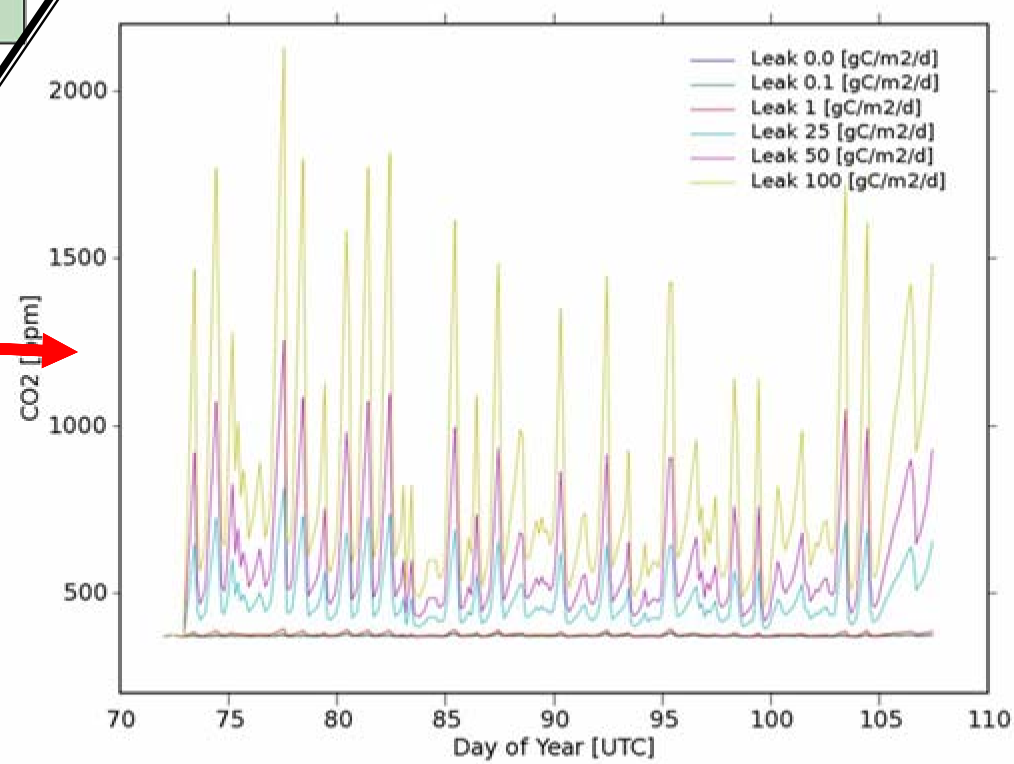
Impact of release can be understood through modules such as the atmospheric module

Atmospheric Variables

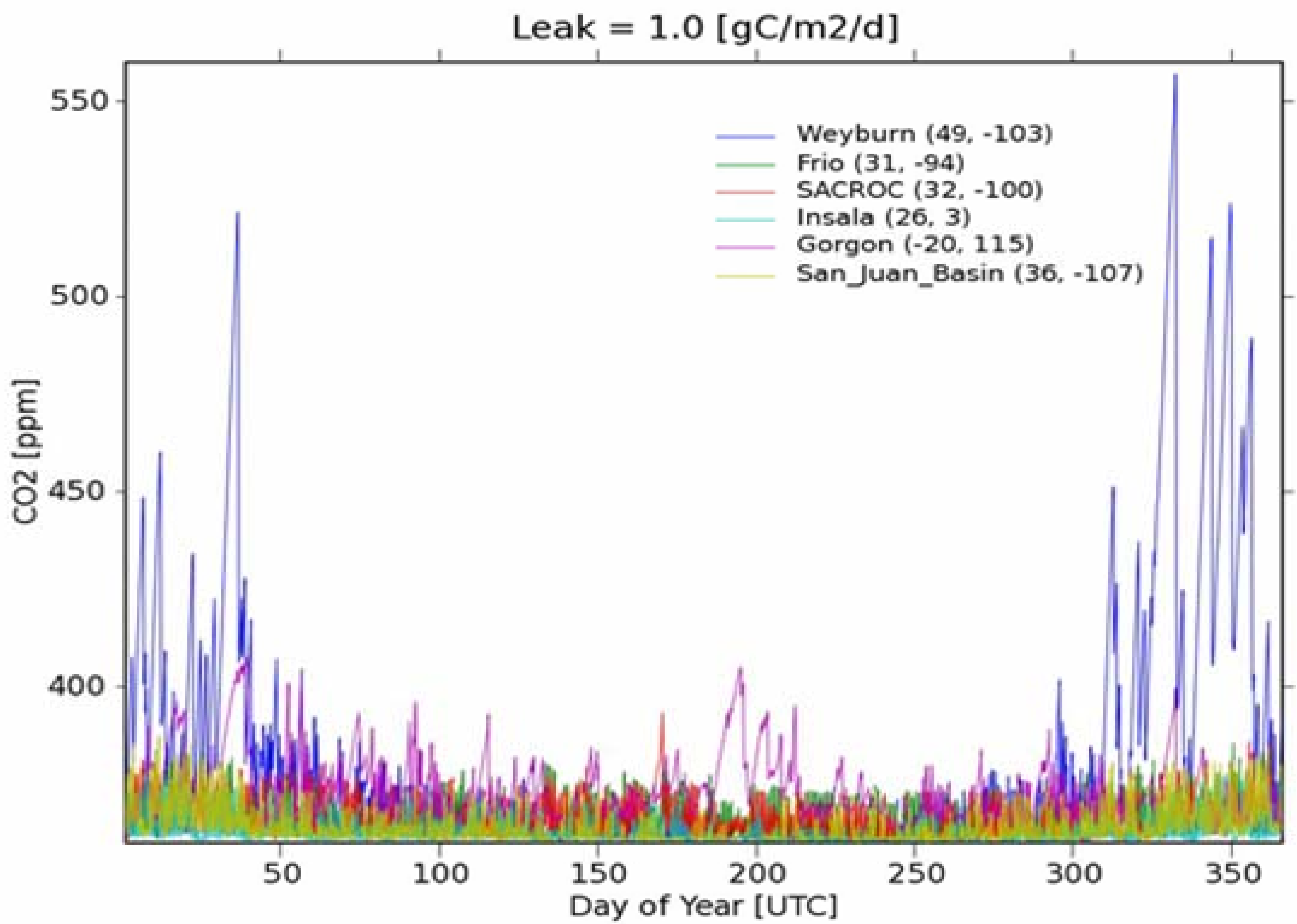
Latitude (degrees)	44
Longitude (degrees)	90
Starting Day (days)	1

Input geographic location information is used by GIS tools to access data on local atmospheric mixing conditions

Local atmospheric mixing conditions and predictions of CO_2 leak flux are used by the atmospheric module to calculate changes in local atmospheric CO_2 concentrations

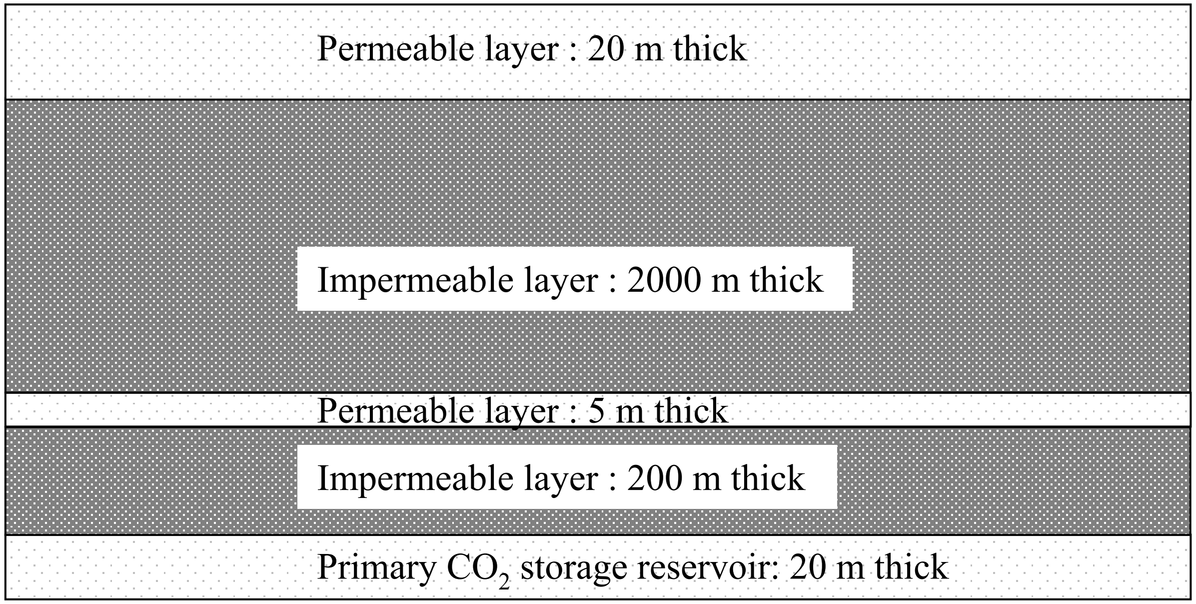


Example: prediction of daily changes in atmospheric CO_2 concentrations at global sequestration sites



Impact of release on shallower strata: example application of CO_2-PENS embedded with Princeton-CMI model

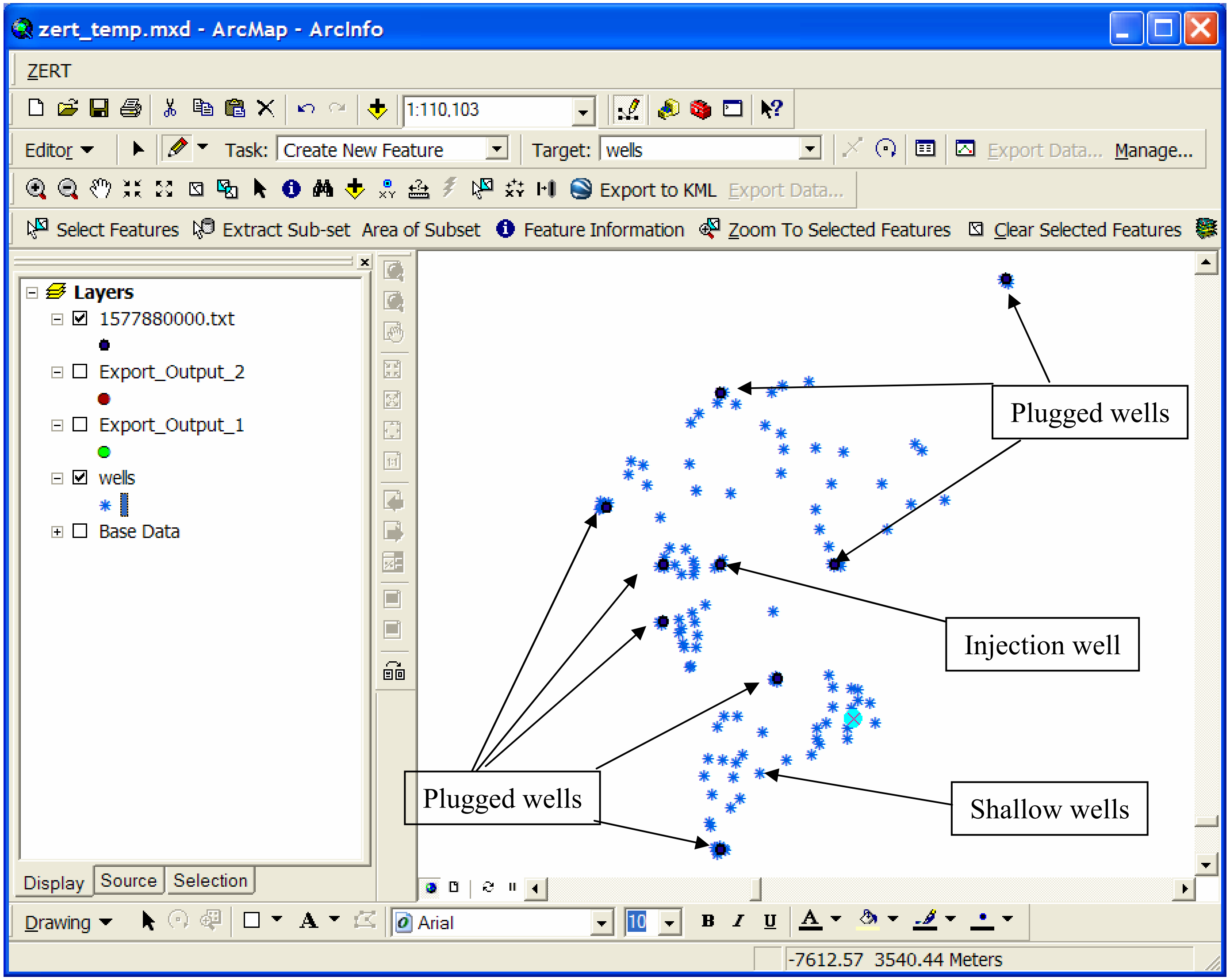
- Injection and release calculations performed using the Nordbotten et al. model from Princeton CMI embedded in CO_2-PENS
  - CO_2-PENS provides input parameters to Princeton model DLL
  - Results from Princeton model are suppled to other CO_2-PENS modules.
- Hypothetical sequestration site:



Example calculation parameters

- 9 wells: 1 injection well, surrounded by 8 plugged wells at different locations
- 2 log-normal distributions used for wellbore cements:
  - Distribution 1: Mean 5e^{-11} m^2, Std. Dev. 2e^{-11} m^2
  - Distribution 2: Mean 3e^{-17} m^2, Std. Dev. 2e^{-17} m^2
- Permeability & porosity of permeable layers sampled from distributions.
  - Distributions generated using GIS tools from well database
- Injection rate sampled from a distribution.
  - 50 years of injection
- Monte-Carlo simulations
  - Values of stochastic parameters for each realization provided to Princeton model

Well locations schematic



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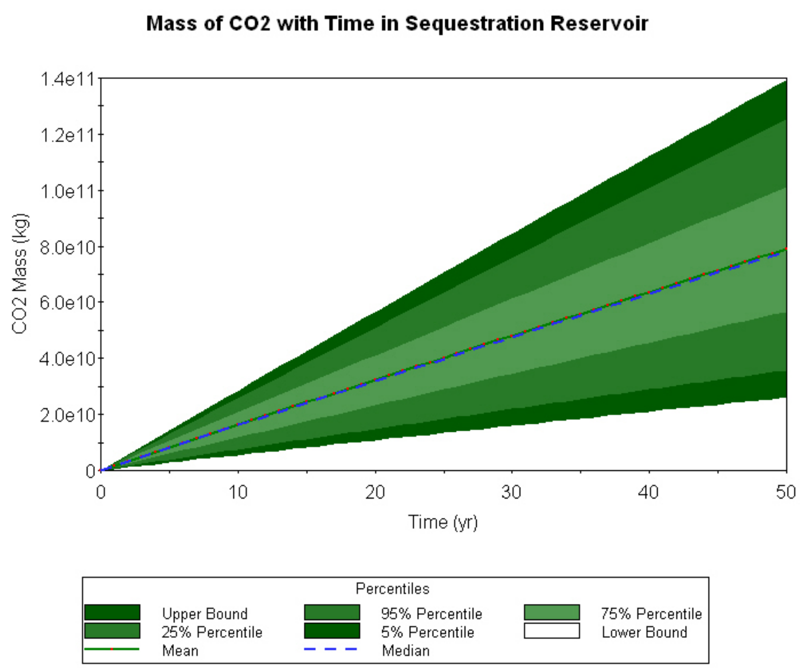
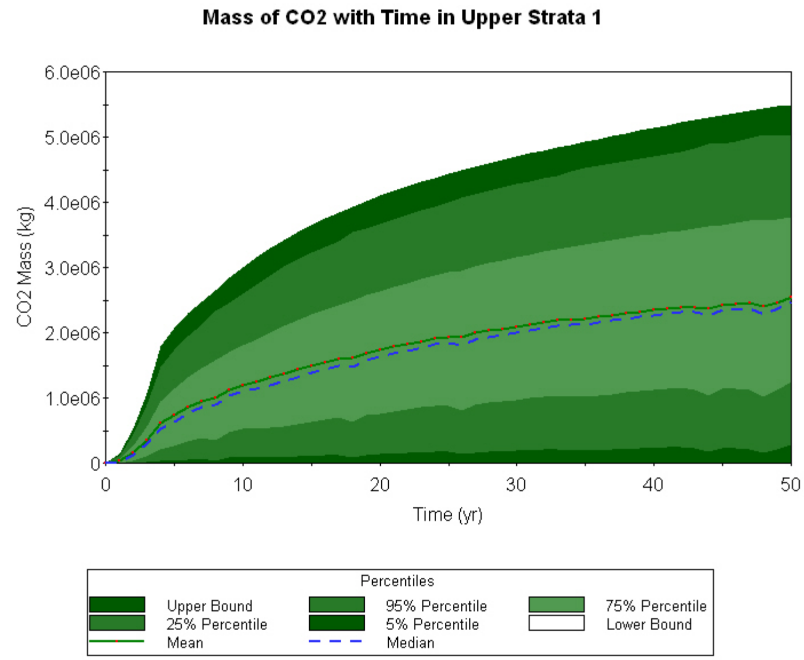
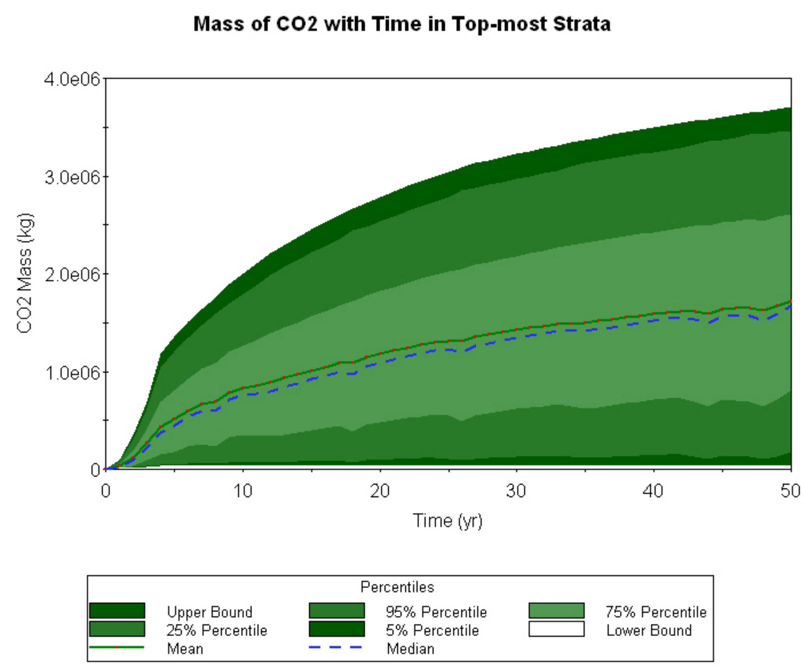
Prediction of CO_2 mass in three strata







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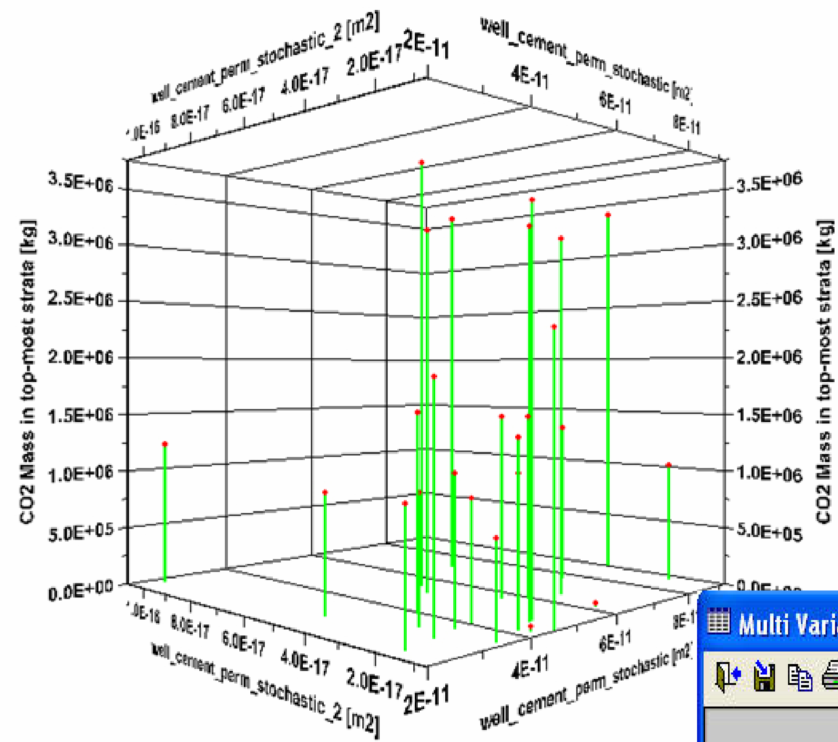
CO_2-PENS has utilities that can be directly used to perform multi-variable analysis

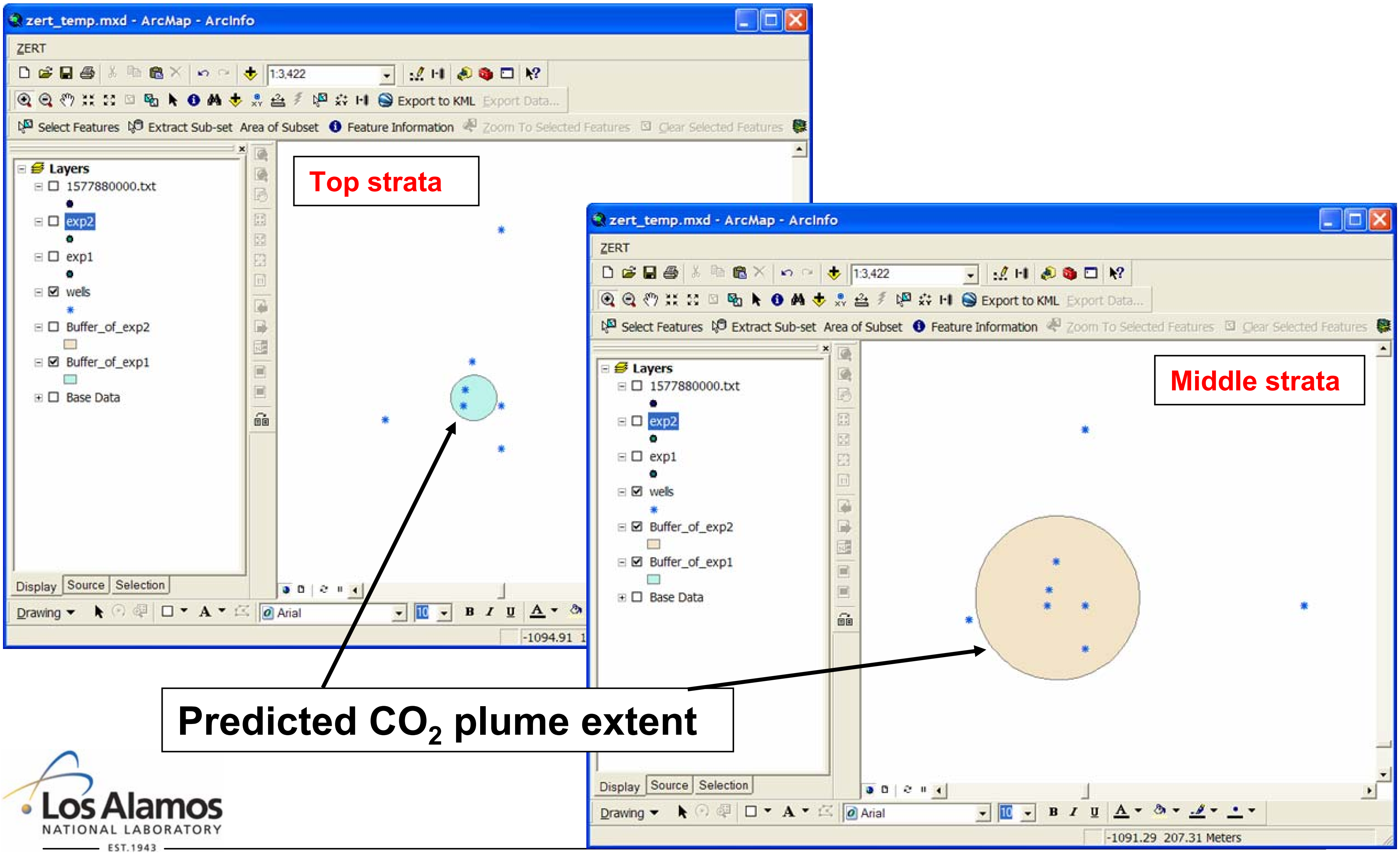


Dependence of mass leaked in top-most layer on the stochastic parameters

Multi Variate Analysis - Value Correlation

	External_	DK_injecti	reservoir	reservoir	upper_str	upper_str	upper_St	upper_str	well_cem	well_cem
External_Dmitri.Mass3	1	0.223	0.165	0.377	-0.532	0.003	0.210	0.447	0.353	0.296
upper_strata2_por_stochastic	0.447	0.171	0.076	-0.141	-0.145	0.007	0.402	1	0.442	-0.006
reservoir_porosity_stochastic	0.377	0.071	0.107	1	-0.400	-0.048	0.199	-0.141	-0.087	0.115
well_cement_perm_stochastic	0.353	0.238	-0.216	-0.087	0.017	-0.387	0.392	0.442	1	0.019
well_cement_perm_stochastic_2	0.296	0.103	0.008	0.115	-0.245	0.059	-0.129	-0.006	0.019	1
DK_injection_rate_stochastic	0.223	1	-0.265	0.071	-0.115	0.052	0.409	0.171	0.238	0.103
upper_Strata2_perm_stochastic	0.210	0.409	-0.074	0.199	-0.115	-0.038	1	0.402	0.392	-0.129
reservoir_perm_stochastic	0.165	-0.265	1	0.107	0.045	-0.090	-0.074	0.076	-0.216	0.008
upper_strata1_por_stochastic	0.003	0.052	-0.090	-0.048	-0.276	1	-0.038	0.007	-0.387	0.059
upper_strata1_perm_stochastic	-0.532	-0.115	0.045	-0.400	1	-0.276	-0.115	-0.145	0.017	-0.245

Leak rates predicted by the Princeton model are used to determine impact of leaked CO_2 plume



GIS tools provide details of the wells which could be exposed to CO_2 plume

Microsoft Access - [wells1 : Table]

OBJECTID	Shape	WELL_NO	WELL_ID	POINT_X	POINT_Y
1	ong binary data		200303	-1007.944885	-6.355895996
2	ong binary data		200405	-1006.885620	6.3560791034
(AutoNumber)					

Record: 1 of 2

Details of shallow wells intercepted by the plume in top-most strata

Microsoft Access - [wells2 : Table]

OBJECTID	Shape	WELL_NO	WELL_ID	POINT_X	POINT_Y
1	ong binary data		200306	-14.75408936	3035.5191040
2	ong binary data		200507	21.311523438	3011.4755249
3	ong binary data		200105	21.311523438	2987.4317017
4	ong binary data		200608	1992.8963013	30.054687504
5	ong binary data		200388	2004.9180908	-30.05462646
6	ong binary data		200122	-976.5026855	-42.07647705
7	ong binary data		200755	-976.5026855	-6.010925291
8	ong binary data		200434	-1000.546387	30.054687504
9	ong binary data		200387	-1007.944885	-6.355895996
10	ong binary data		200387	-1006.885620	6.3560791034
(AutoNumber)					

Record: 1 of 10

Details of shallow wells intercepted by the plume in middle strata

Conclusions

- Large scale deployment of geologic CO_2 sequestration will require a robust approach for long-term performance assessment & risk calculations.
- We have developed a systems level model, CO_2-PENS, based on the science based prediction approach, that can be used to predict performance of a geologic CO_2 storage site based on a number of performance criteria.
- **Is the community ready to predict with 100% certainty 0% leak? Understanding and effectively communicating the ultimate impact of leaks will be the key to success**

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Contacts for further information on CO_2-PENS

Rajesh Pawar, rajesh@lanl.gov

Phil Stauffer, stauffer@lanl.gov

Hari Viswanathan, viswana@lanl.gov

George Guthrie, gguthrie@lanl.gov

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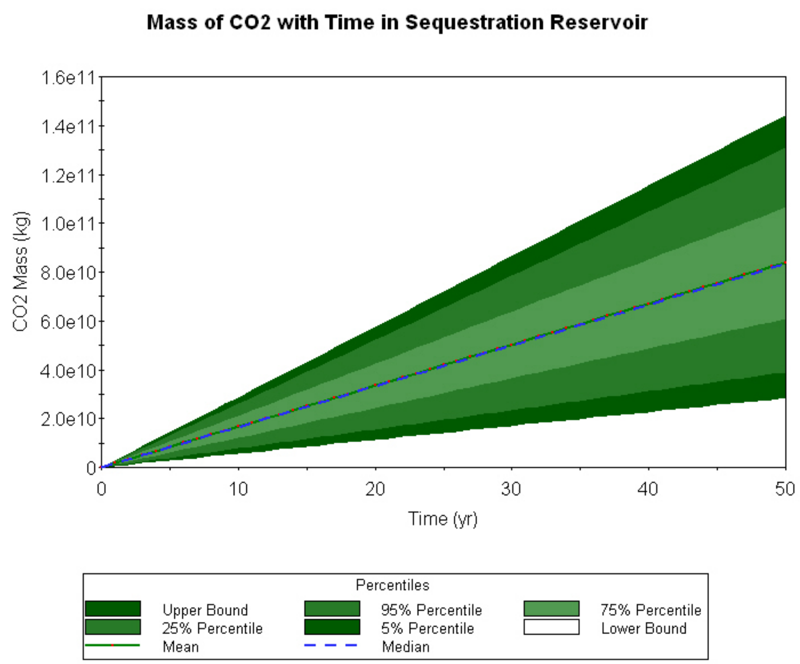
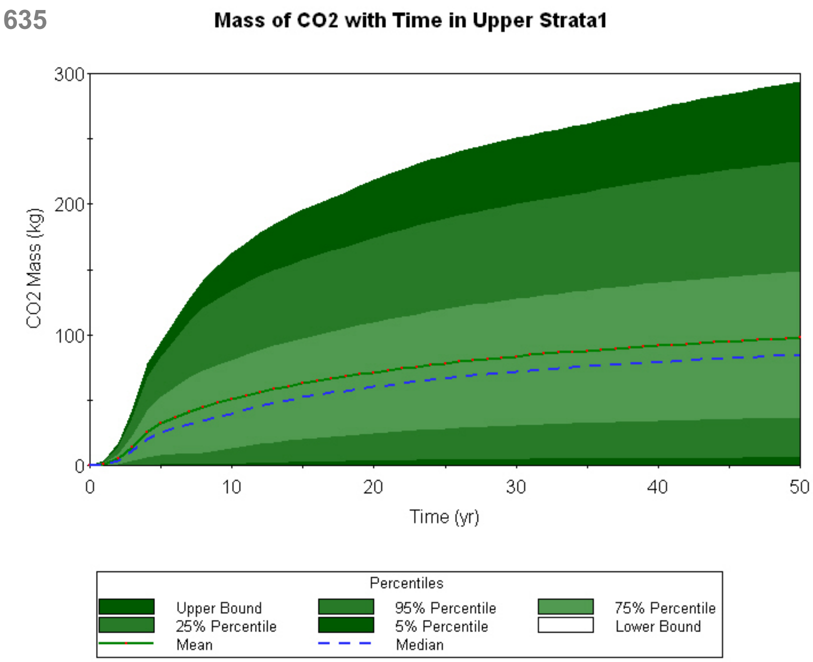
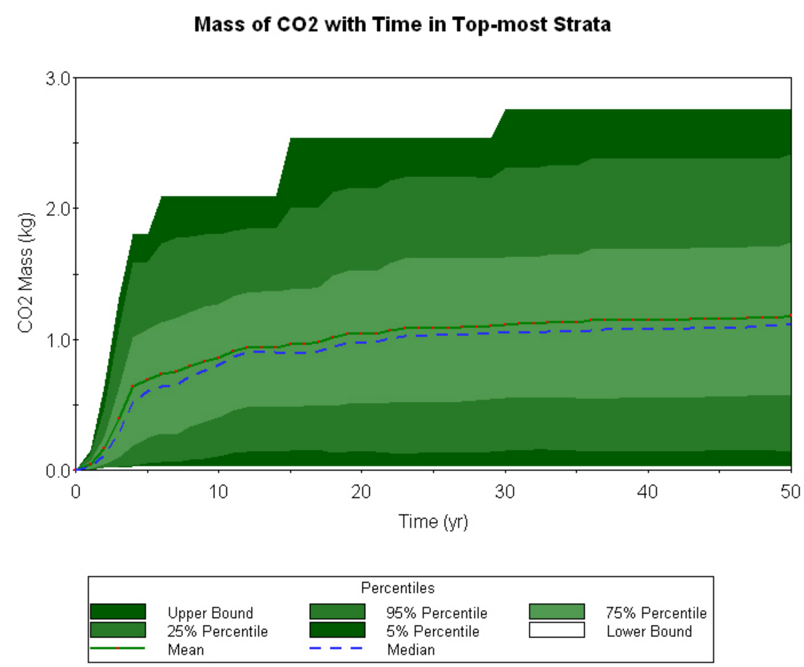
Prediction of CO_2 mass in three strata: low cement perms (3e-17 m2)







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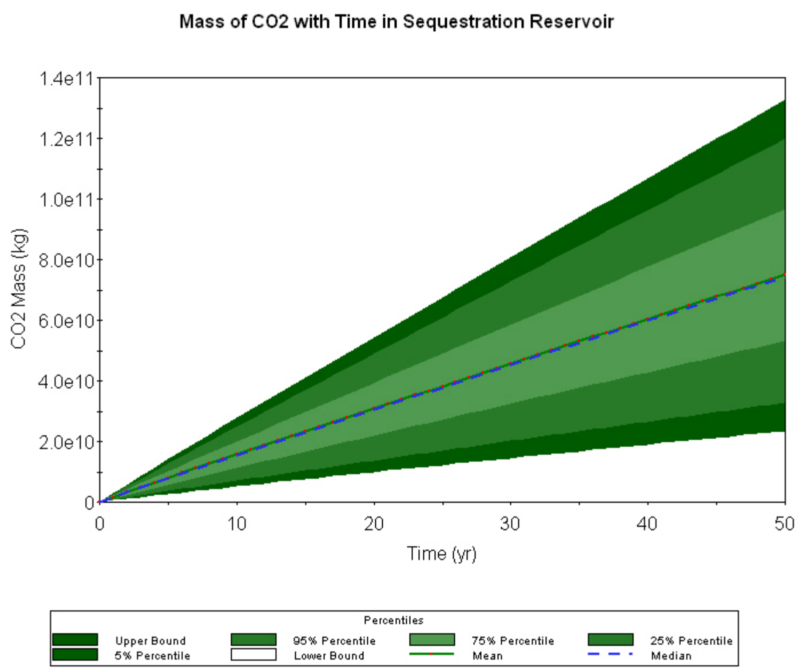
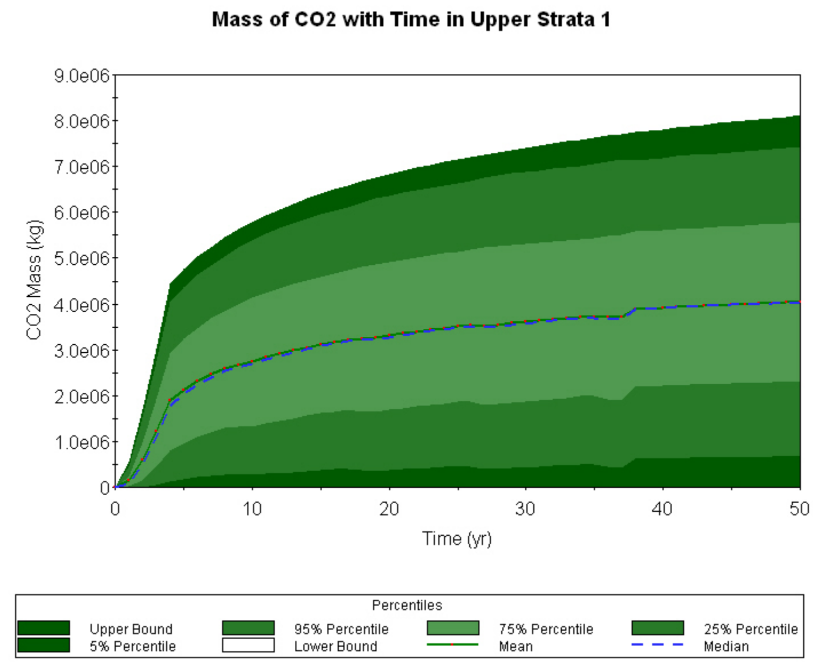
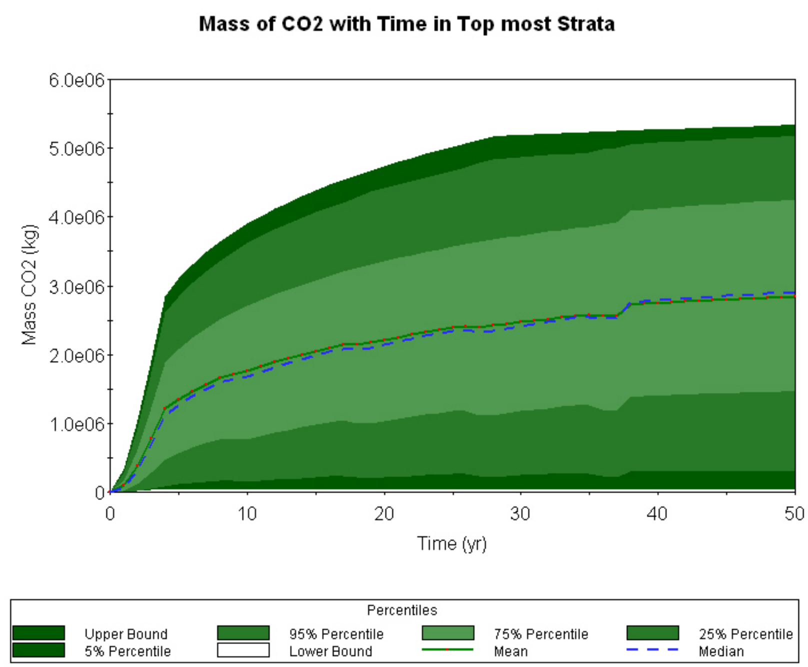
Prediction of CO_2 mass in three strata uniform spacing







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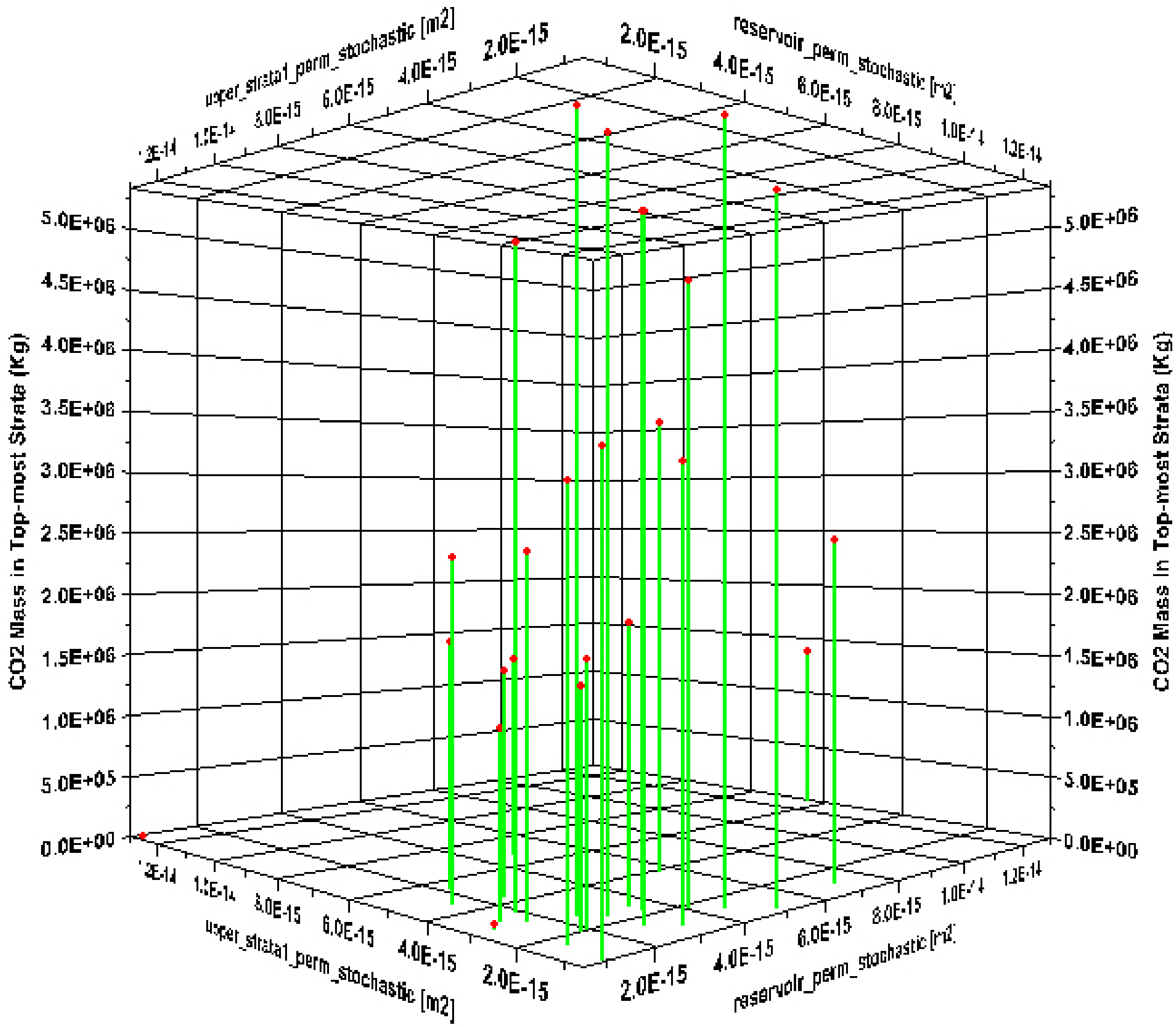
CO_2-PENS has utilities that can be directly used to perform multi-variable analysis



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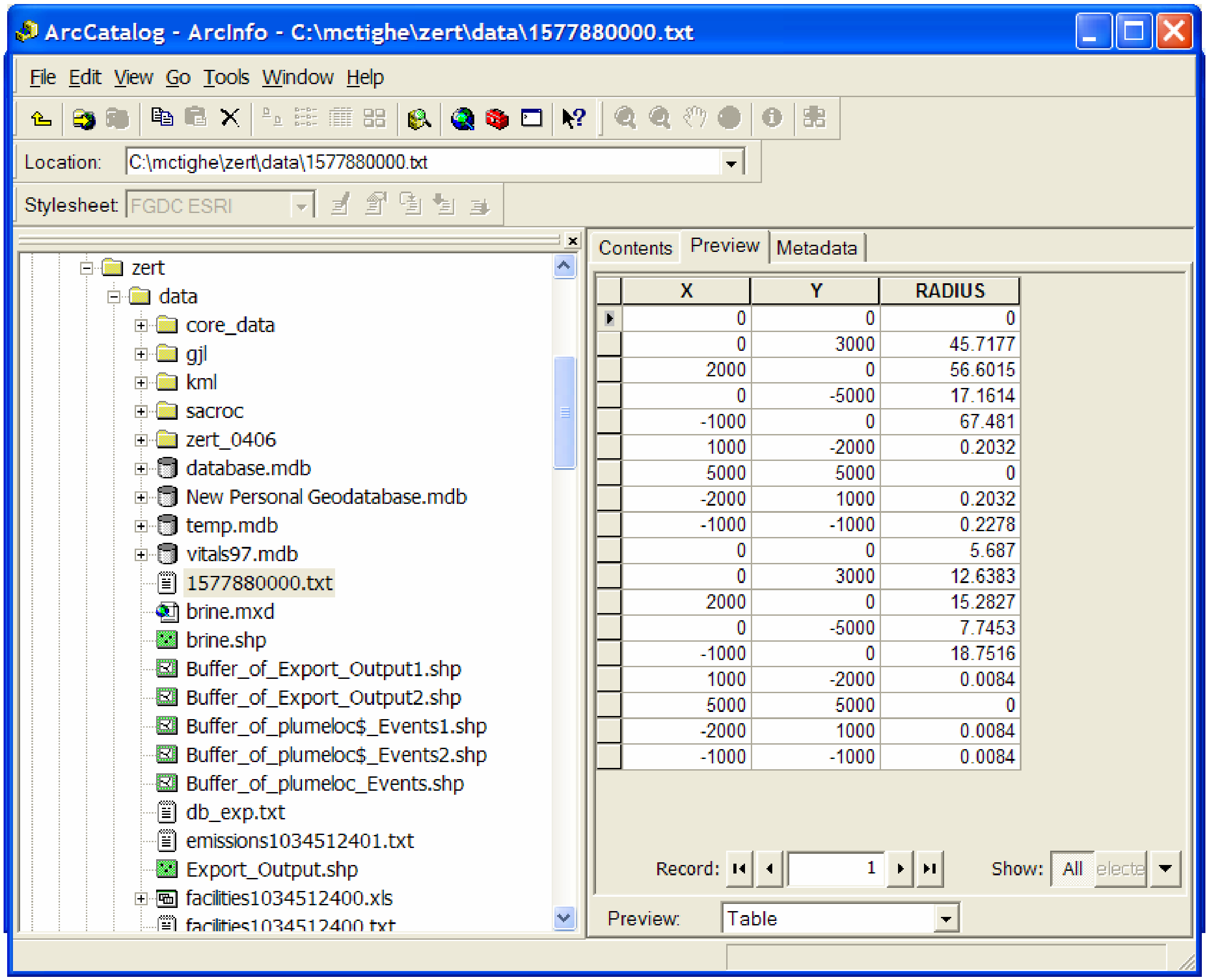
Dependence of mass leaked in top-most layer on the different stochastic parameters in the example

Multi Variate Analysis - Value Correlation

	External_	DK_injecti	reservoir	reservoir	upper_str	upper_str	upper_St	upper_str	well_cem	well_cem
External_Dmitri.Mass3	1	0.321	0.078	0.425	-0.557	-0.042	0.464	0.485	0.529	0.264
well_cement_perm_stochastic	0.529	0.238	-0.216	-0.087	0.017	-0.387	0.392	0.442	1	0.019
upper_strata2_por_stochastic	0.485	0.171	0.076	-0.141	-0.145	0.007	0.402	1	0.442	-0.006
upper_Strata2_perm_stochastic	0.464	0.409	-0.074	0.199	-0.115	-0.038	1	0.402	0.392	-0.129
reservoir_porosity_stochastic	0.425	0.071	0.107	1	-0.400	-0.048	0.199	-0.141	-0.087	0.115
DK_injection_rate_stochastic	0.321	1	-0.265	0.071	-0.115	0.052	0.409	0.171	0.238	0.103
well_cement_perm_stochastic_2	0.264	0.103	0.008	0.115	-0.245	0.059	-0.129	-0.006	0.019	1
reservoir_perm_stochastic	0.078	-0.265	1	0.107	0.045	-0.090	-0.074	0.076	-0.216	0.008
upper_strata1_por_stochastic	-0.042	0.052	-0.090	-0.048	-0.276	1	-0.038	0.007	-0.387	0.059
upper_strata1_perm_stochastic	-0.557	-0.115	0.045	-0.400	1	-0.276	-0.115	-0.145	0.017	-0.245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-2000 1000 0.2032
-1000 -1000 0.2278
0 0 5.687
0 3000 12.6383
2000 0 15.2827
0 -5000 7.7453
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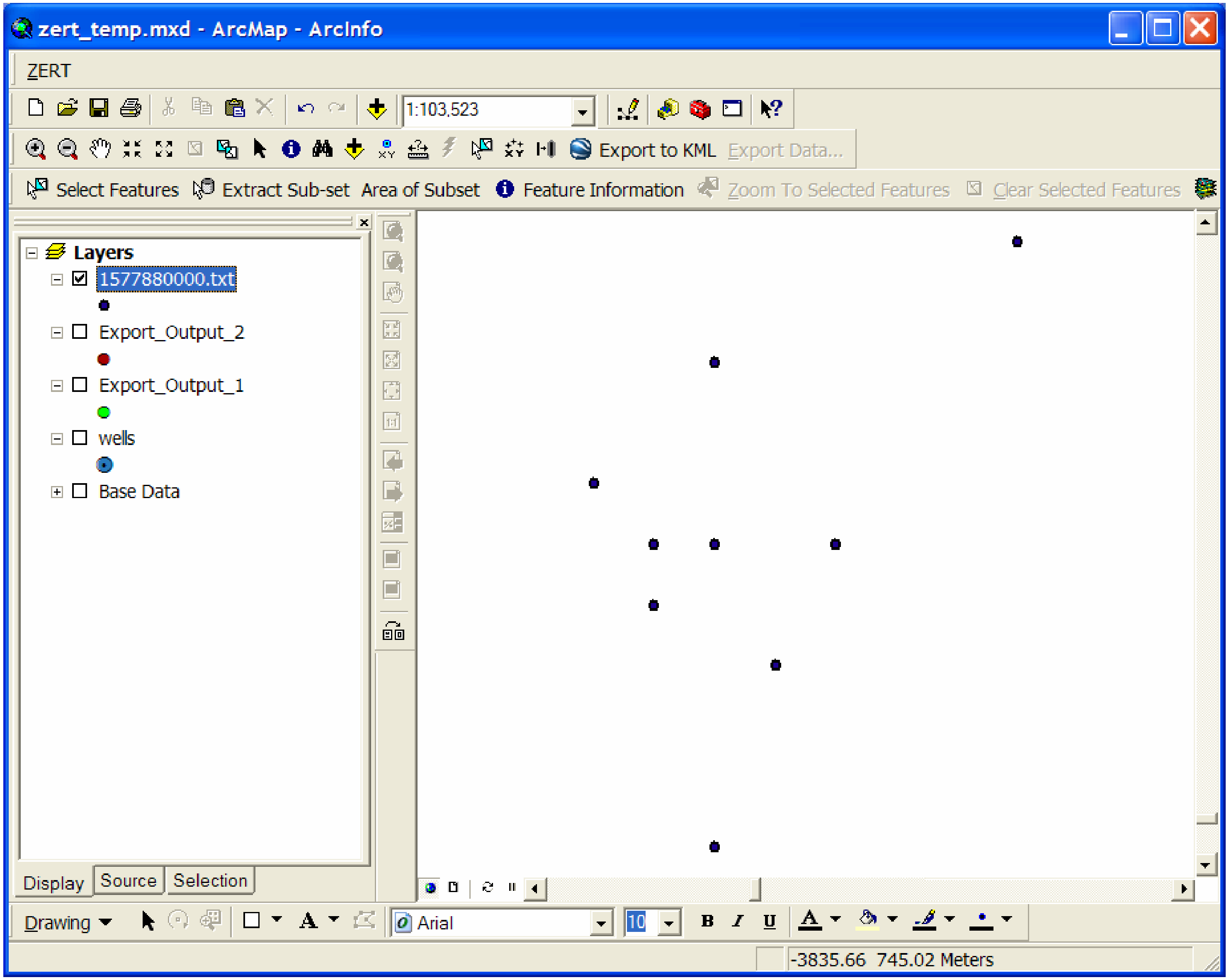
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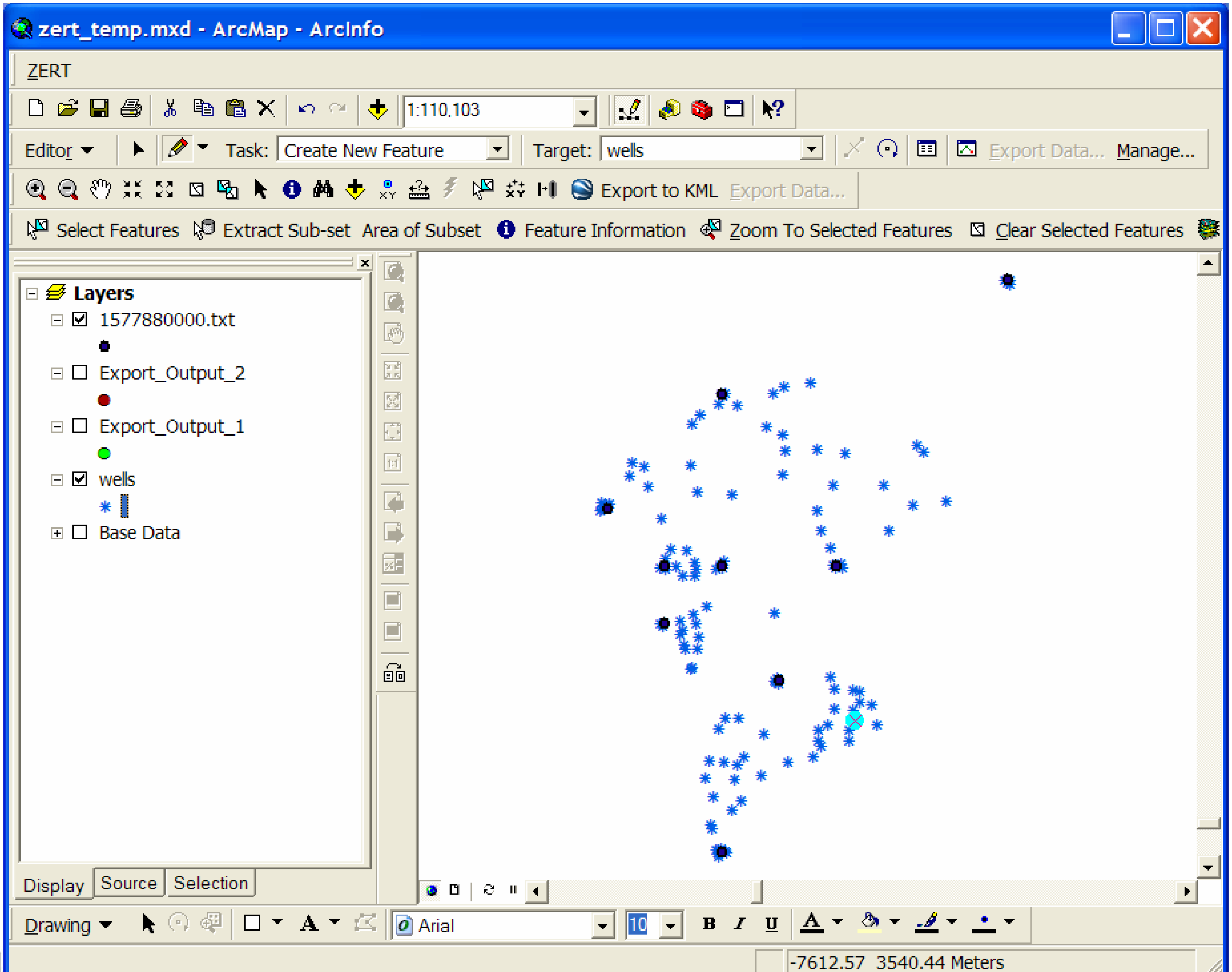

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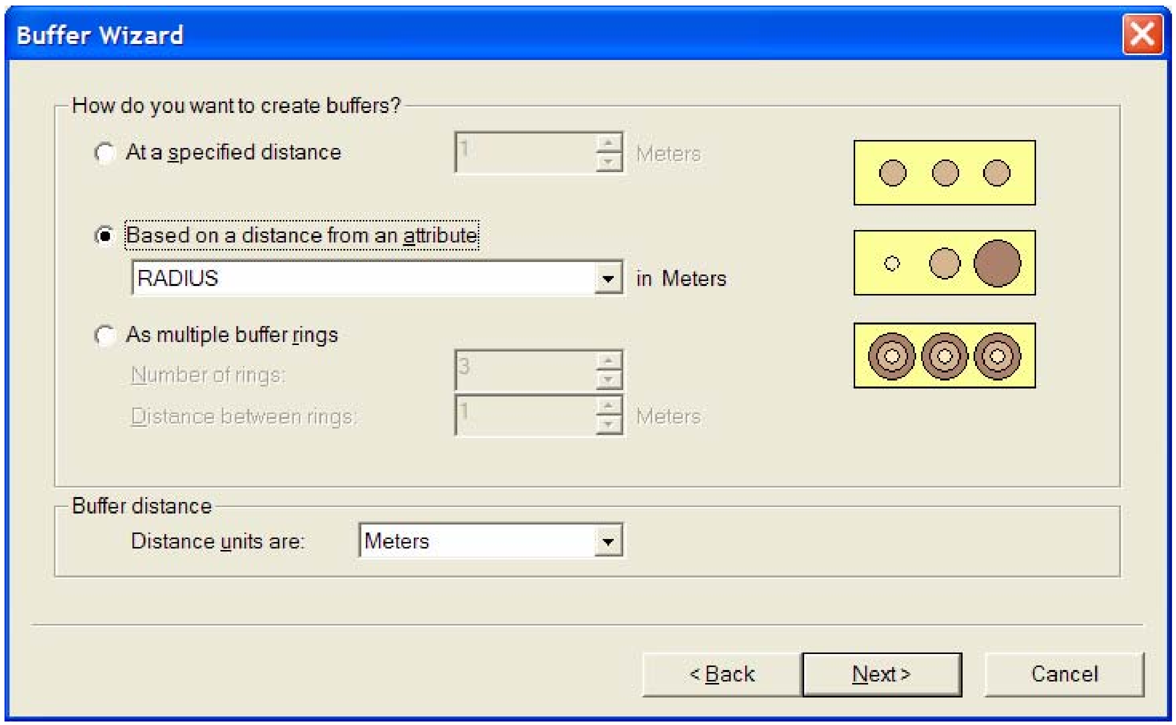
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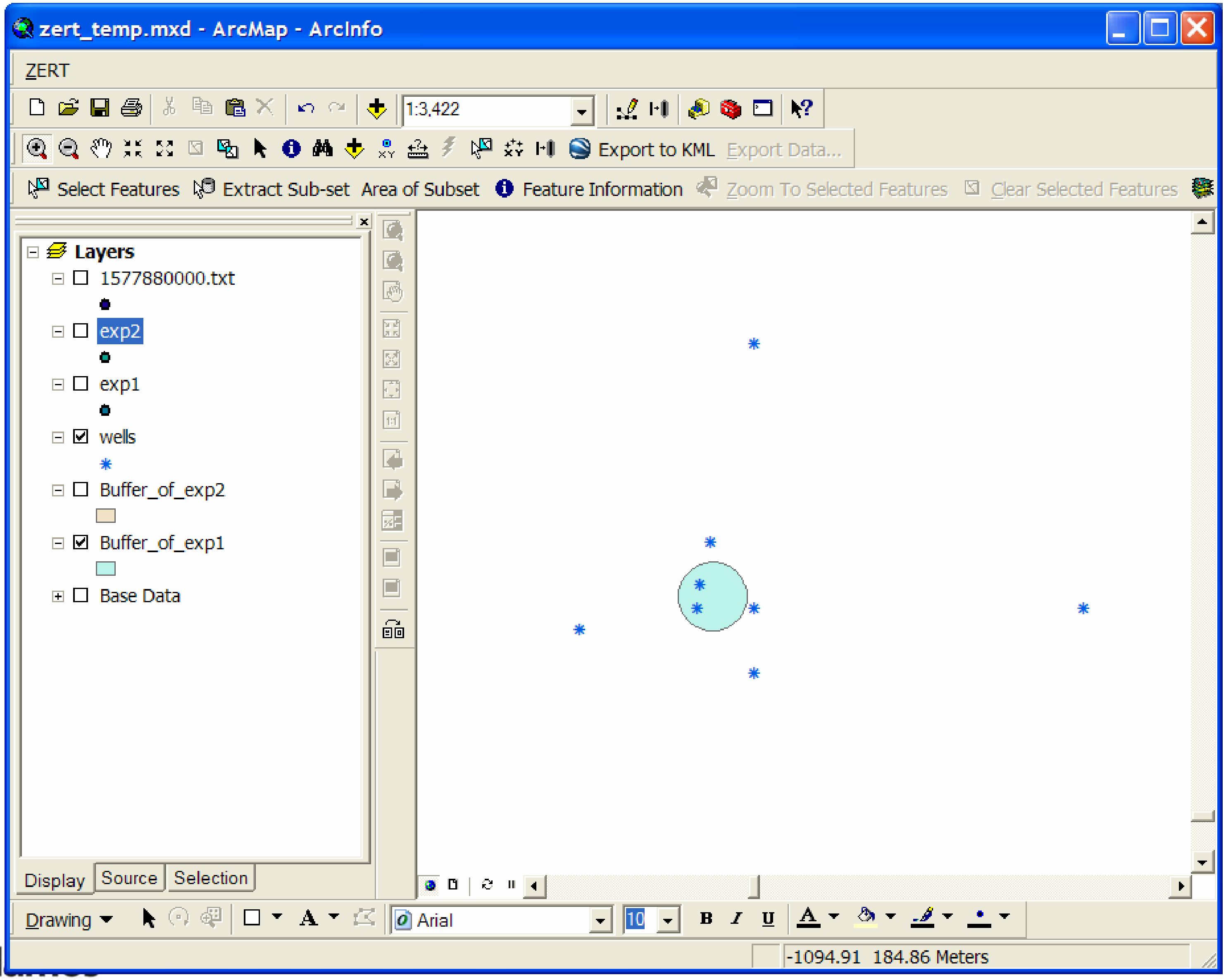
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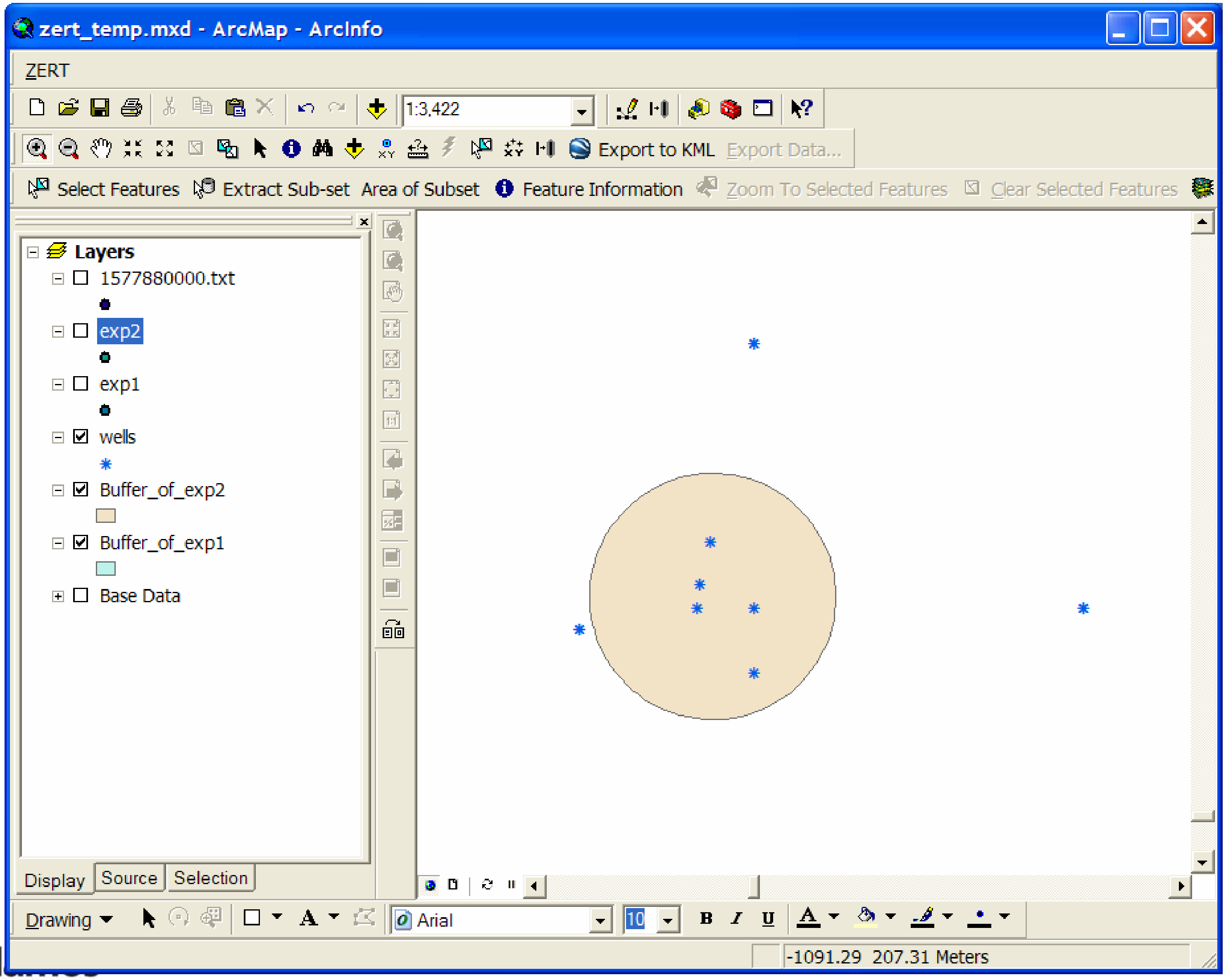
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Microsoft Access - [wells1 : Table]

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Microsoft Access - [wells2 : Table]

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6	ong binary data		200122	-976.5026855	-42.07647705
7	ong binary data		200755	-976.5026855	-6.010925291
8	ong binary data		200434	-1000.546387	30.054687504
9	ong binary data		200387	-1007.944885	-6.355895996
10	ong binary data		200387	-1006.885620	6.3560791034
(AutoNumber)					

Record: 1 of 10

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energy API

RP 65 and other API Activities on Carbon Capture and Storage

Co-authors: R. Sweatman, S. Crookshank. M. Parker, S. Meadows, K. Ritter, B. Bellinger

Presented at

3rd Well Bore Integrity Network Meeting

Santa Fe, New Mexico

12-13 March, 2007

Organized by:

IEA Greenhouse Gas R&D Programme

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bp

EPRI Electric Power Research Institute

API History and Mission

- **1919: API founded as national trade association for US oil and gas industry**
- **API is only US trade association representing all segments of oil and gas industry**
- **API represents industry before government, develops standards, and conducts research**
- **Certification Program for ISO 14001 on Environmental Management System**

API Standards Process

- **The Process is**
  - Open
  - Transparent
  - Consensus-based

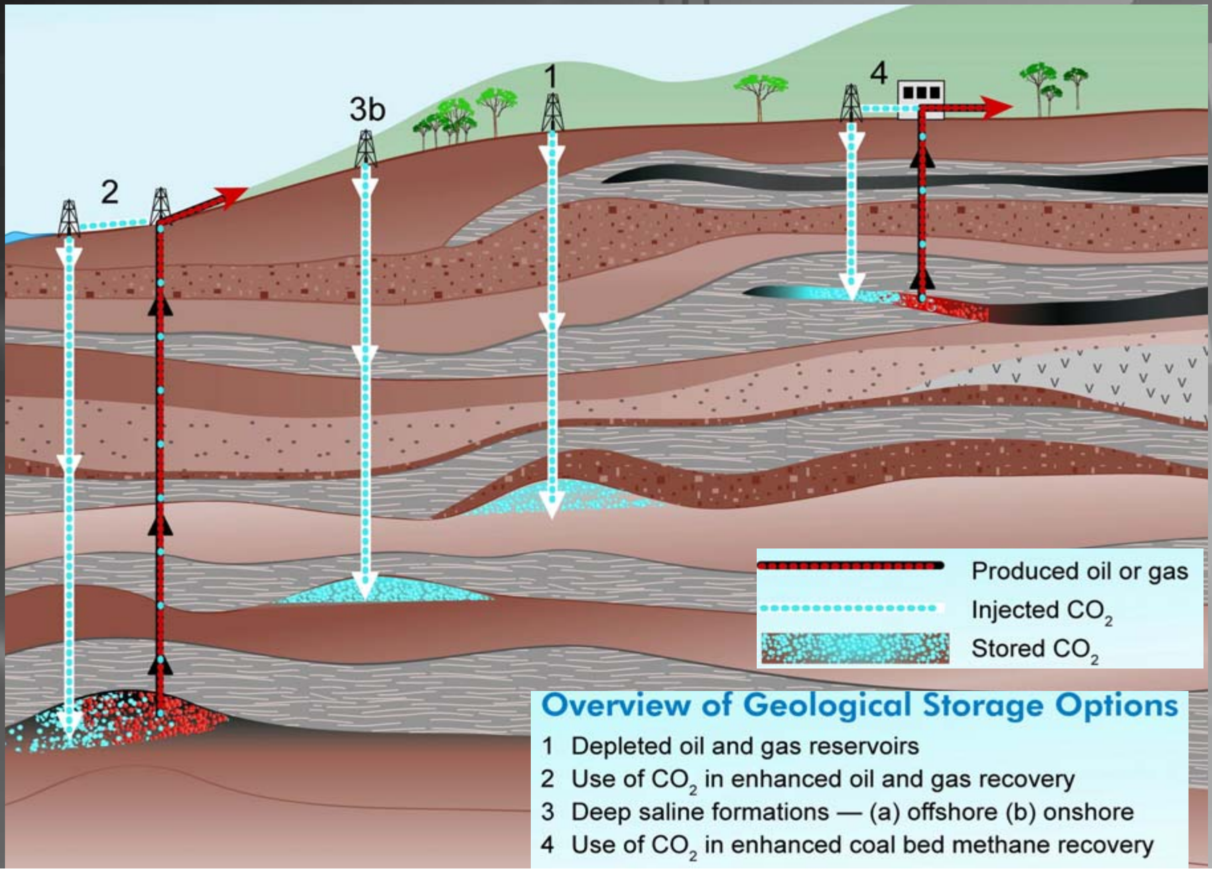
API is an American National Standards Institute (ANSI) accredited Standards Developing Organization

Major API Activities for CCS

- CCS Work Group
- API/IPIECA CCS Project Guidance Committee
- API RP 90: Annular Casing Pressure Management
- API RP 65: Annular Pressure Containment
- API/DOE Conferences

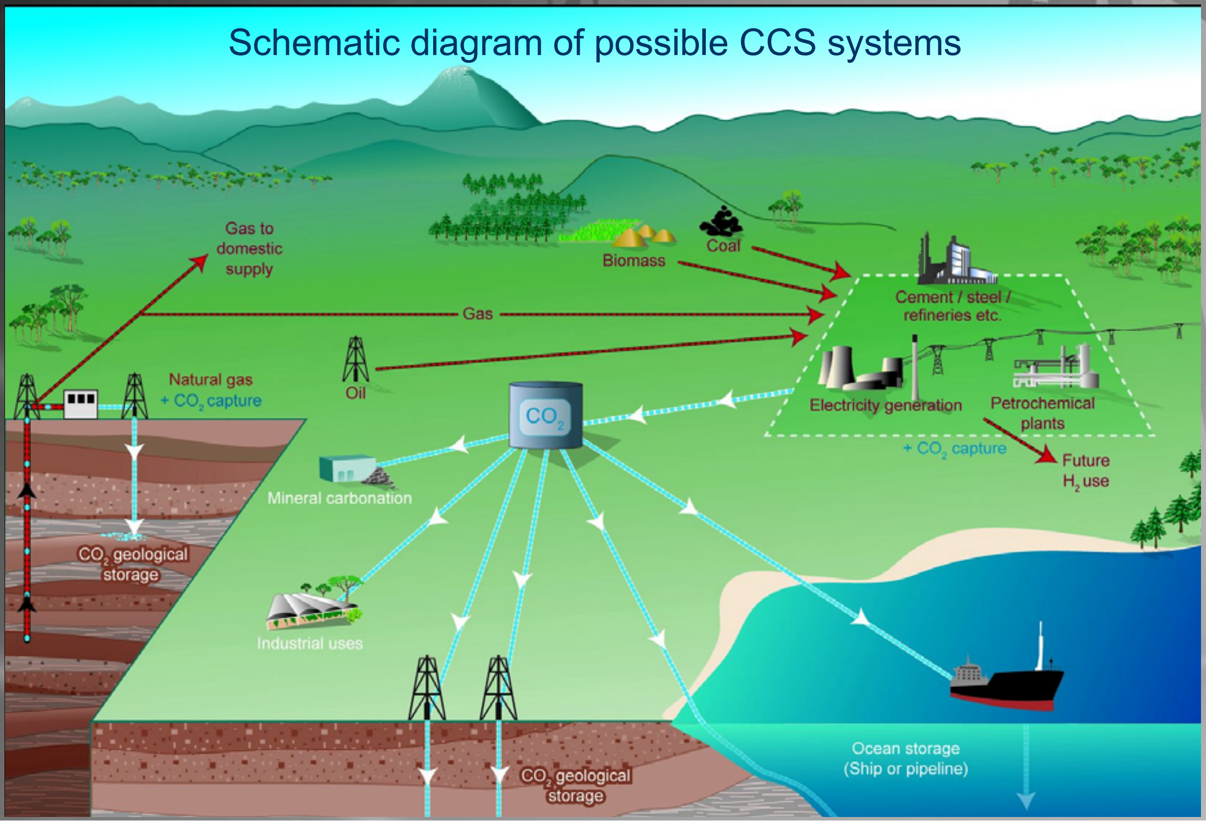
CCS Work Group - Mike Parker, ExxonMobil

- Upstream Environmental (Water) & Production Experts
- Studying CO_2 Enhanced Oil Recovery Practices
- Working on a Report of Industry Experiences



Guidelines for Emission Reductions from CCS Projects

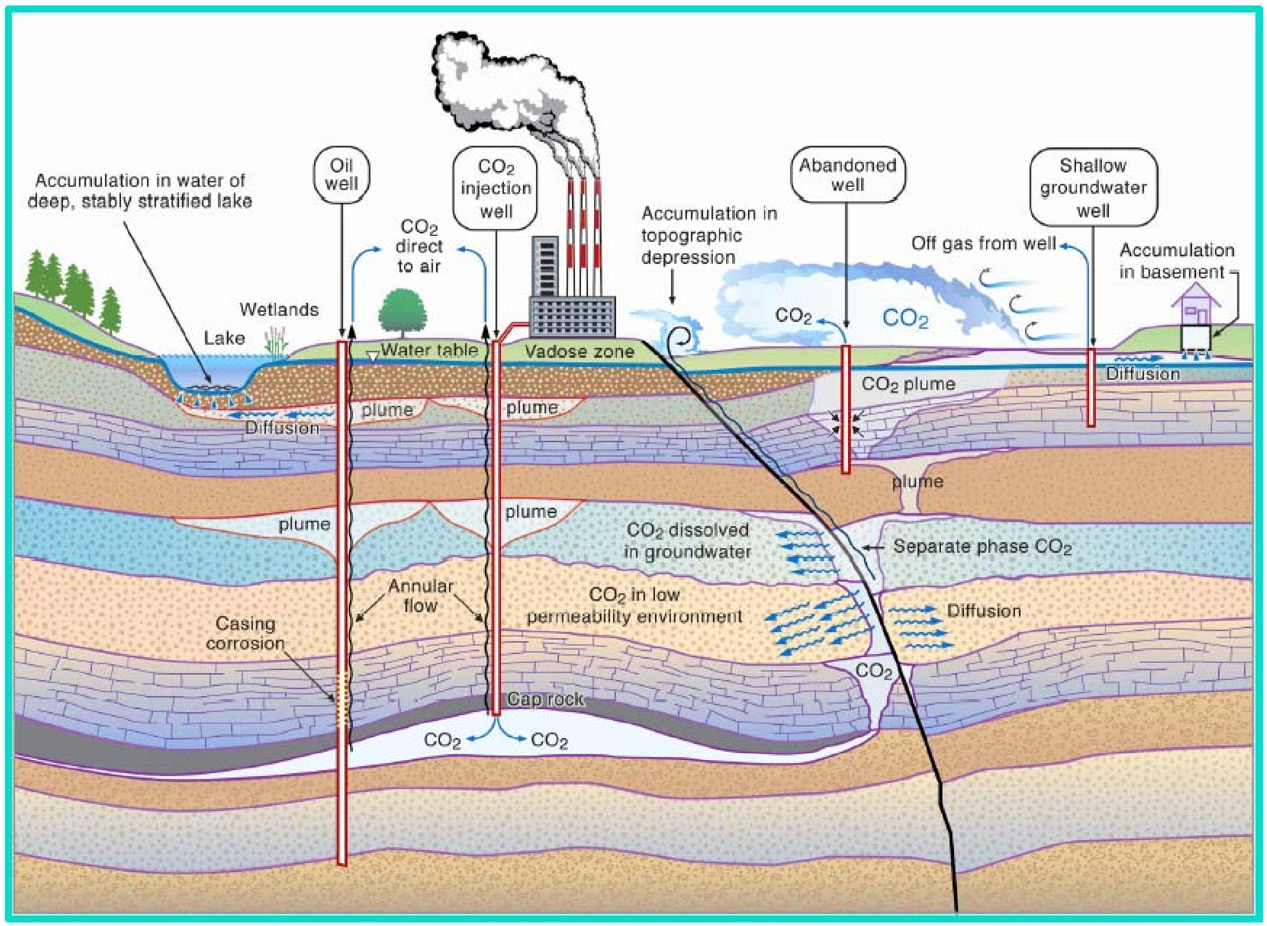
- **Frede Cappelen, Statoil**
- Joint API/IPIECA Project
- GHG Inventory Experts and CCS Experts
- May, 2007



API/IPIECA CCS Project Emission Reductions

Common issues

- Boundary
- Baseline
- Additionality
- Methodology
- Monitoring

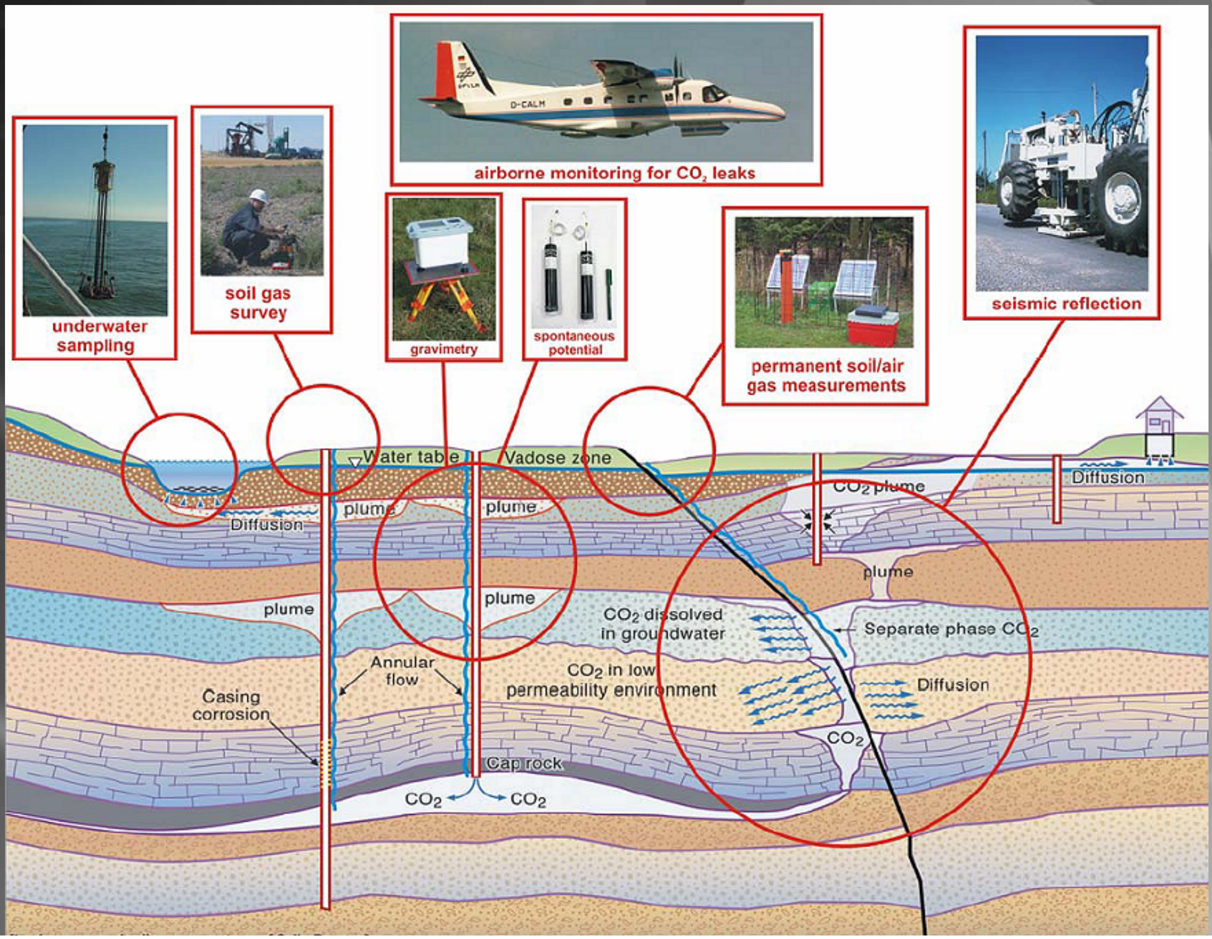


API/IPIECA Project Guidance Objectives

- Provide guidelines on identifying, assessing, and developing candidate projects that would lead to credible emission reductions
- Develop a framework for assessing emission reductions associated with specific project "families", including references to relevant methodologies or guidance
- Requires the application of oil industry expertise
- Guidance to be regime neutral

Example Monitoring Techniques

- Tailored to site specific characteristics
- Provide data to update modeling & risk assessment



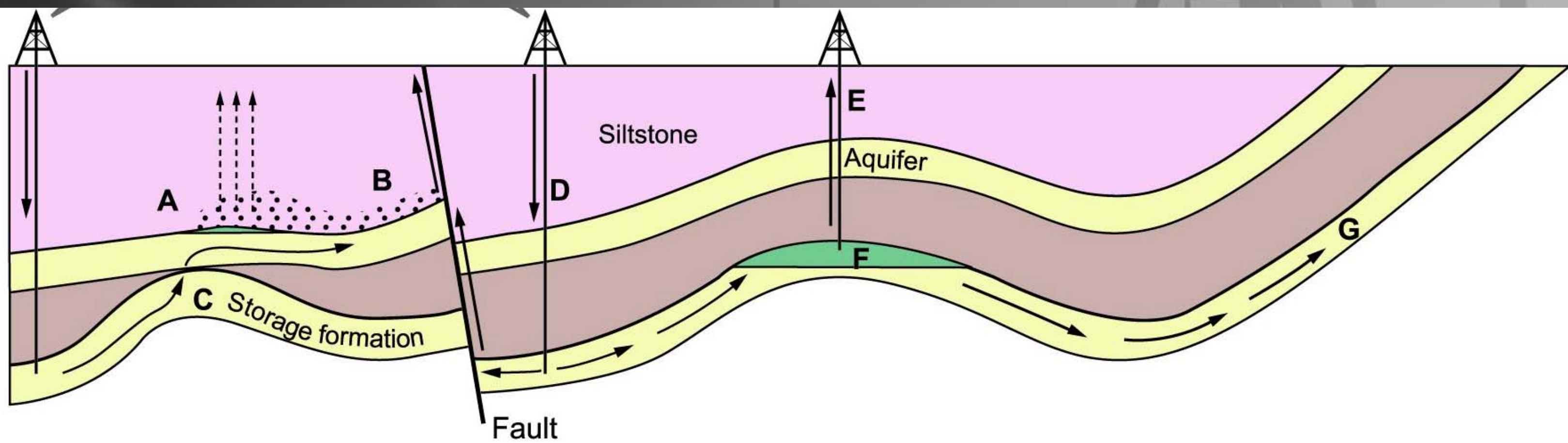
API RP 90 Committee - Phil Smith, Shell

Annular Casing Pressure Management for Offshore Wells

- Well Planning & Design (refers to API RP-65 for barriers)
- Pressure Containment Design Considerations
- Maximum Allowable Wellhead Operating Pressure
- Detection and Monitoring of SCP and APB (thermal ACP)
- Diagnostic Testing
  - Determines Severity & Need for Remediation
  - SCP Pathways & Source Zones (more in RP 65-3)
- Well Barriers and Barrier Elements
- Casing Integrity Pressure Testing
- Record Keeping
- Risk Analysis Considerations

RP 65 Task Group - Ron Sweatman, Halliburton

- Drilling, Production and Other Experts such as Regulators, Academia
- Studying Well Casing Pressure Prevention and Remediation Practices
- Recommended Practices intended for US Federal Regulations
- RP 65-2 (relevant for preventing CO_2 leaks during well construction)
  - Pressure Barrier and other Related Well Construction Practices
  - Passed letter ballot Feb'07 with comments to resolve
- RP 65-3 (includes prevention and remediation of CO_2 leaks)
  - Pressure Barrier Practices for Well Injection, Production and Abandonment
  - Started last year and expect publication in late 2008 or 2009



Potential Escape Mechanisms

SCP Sources

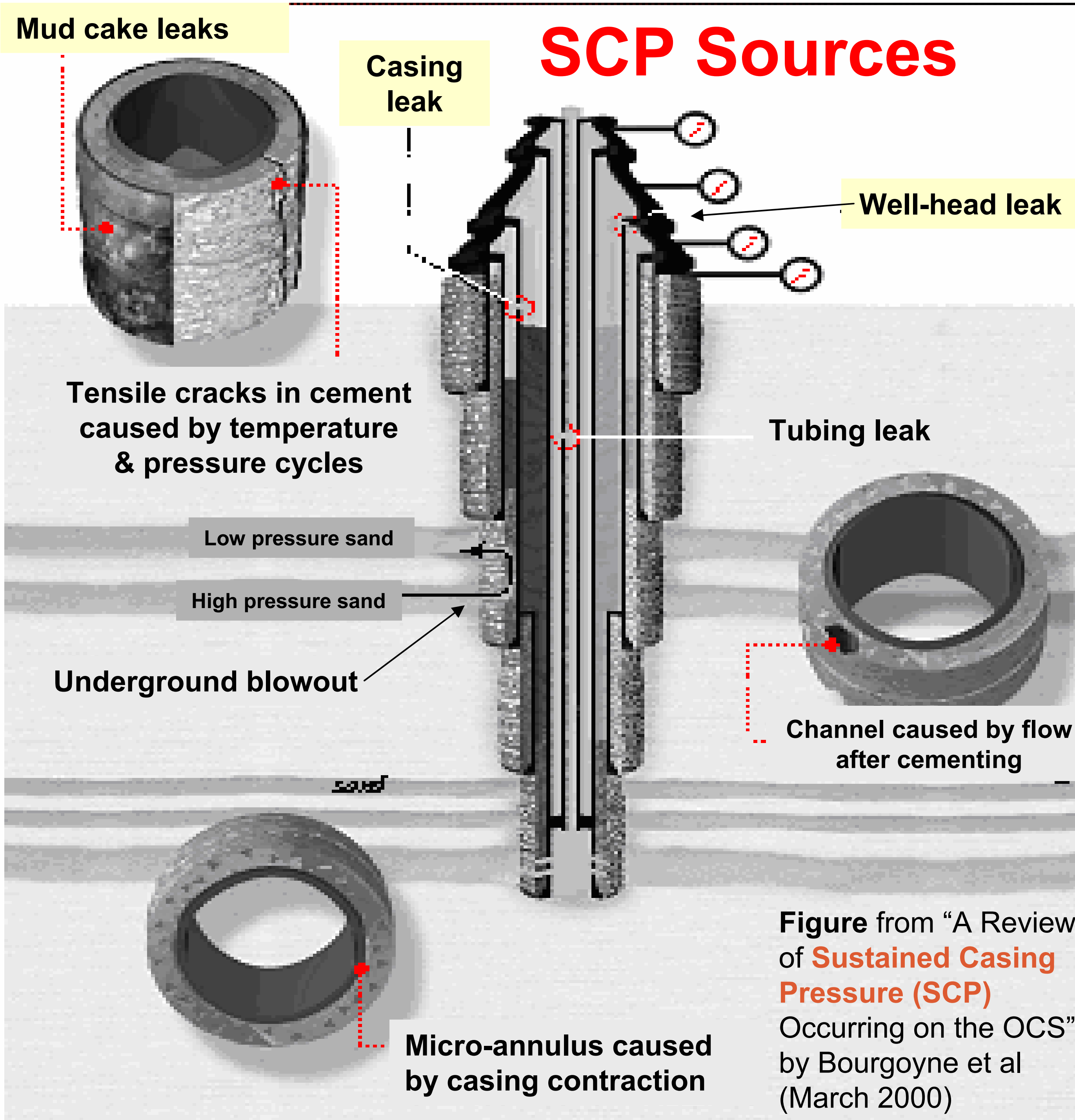


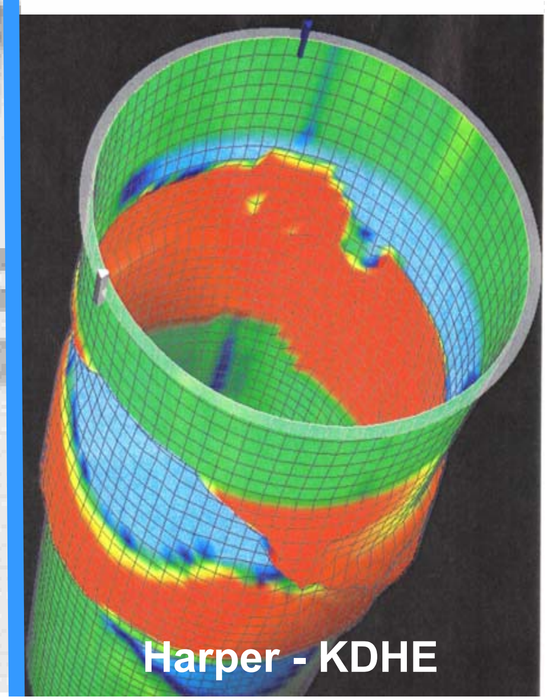
Figure from "A Review of **Sustained Casing Pressure (SCP)** Occurring on the OCS" by Bourgoyne et al (March 2000)

APB

Csg.

Burst

Corrosion Damage



RP 65-3 Draft Outline (Summary)

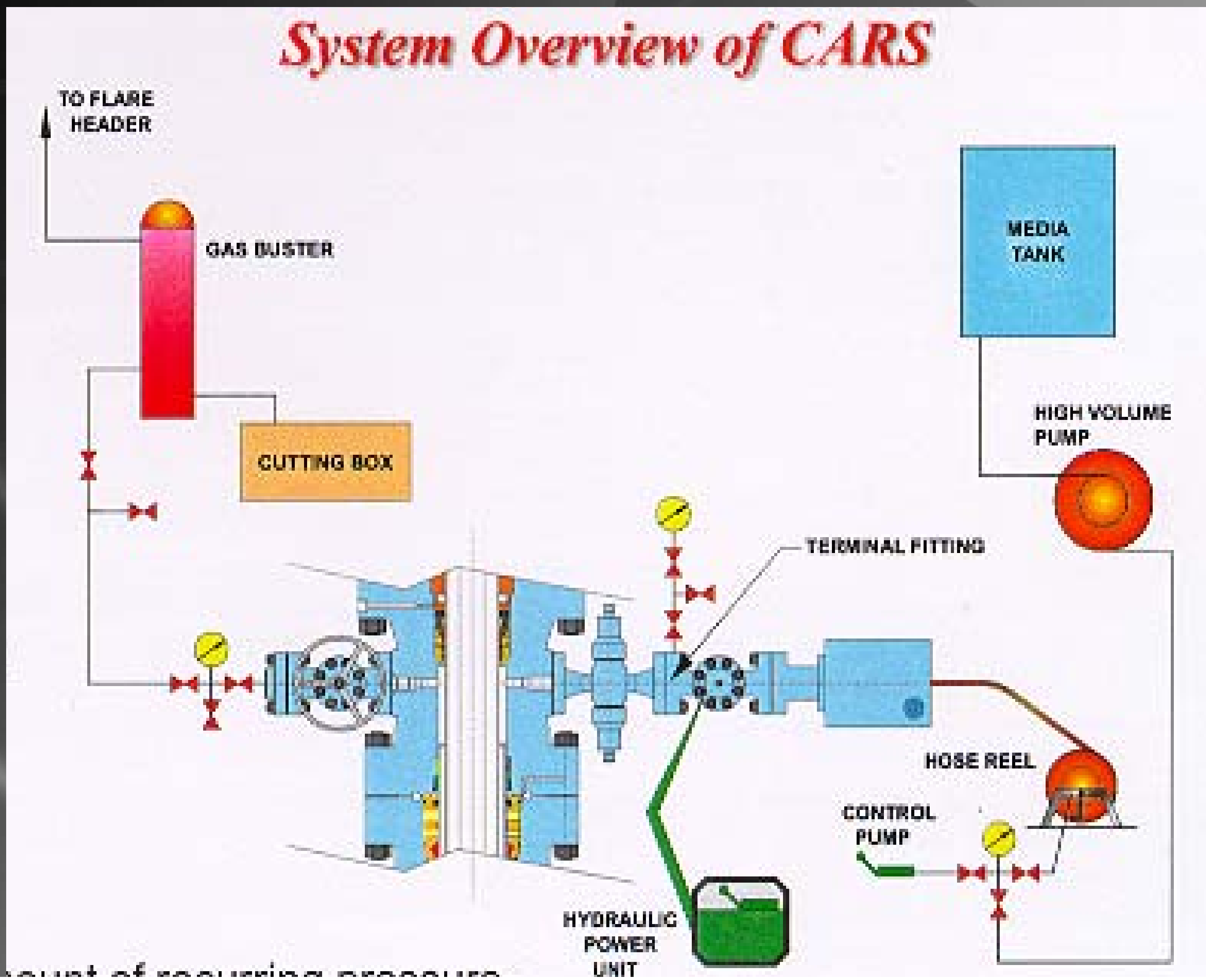
Preventive Practices for Well Construction & Production

- ✓ Well Planning & Design (not in API RP 90, 65-2 or ISO)
- ✓ Detection & Diagnostics: SCP Sources and Pathways
- ✓ SCP Barriers: Mechanical, Cement, Rock & Chemical Sealants
- ✓ Thermal ACP or APB (Annular Pressure Build-Up): Avoidance, Prevention & Venting
- ✓ Well Integrity Testing (Pipe, Shoe, Lap, Packer, etc.)

Remedial Practices for Workovers & Abandonment

- ✓ CP Detection & Diagnostics: Sources, Pathways, etc.
- ✓ Annular Barrier Sealing Methods and Materials (Rig & Rig-less)
- ✓ Rock Permeability Barriers
- ✓ Casing/Liner Pipe Repair Methods and Materials
- ✓ Pressure Seal Evaluation Methods

RP 65 Study - Example of Remediation



Questions, Comments, and New Members are Welcome

RP 65-3 Scope and Objective

Title: **"Practices to Prevent or Remediate Annular Casing Pressure"**

Scope & Objective:

Communicate proven practices to prevent, detect, diagnose, and remediate annular casing pressure (ACP) during well construction, production, injection, & abandonment:

- **Sustained Casing Pressure (SCP) by formation or injected fluids (hydrocarbons, CO_2, H_2S, H_2O, brine, etc.)**
- **Thermal induced ACP (TIACP) caused by trapped fluid pressure inside or near the wellbore**

Include other practices that may:

a) Positively or negatively affect pressure barriers

b) Help avoid or vent TIACP

c) Increase or decrease the occurrence of SCP and TIACP

RP 65-3 Draft Outline

Preventive Practices for Sustained Well Integrity

- Well Planning & Design
  - Avoiding & Venting Annular Pressure Traps
  - Pressure Barrier Selection & Design
  - Corrosion Prevention Methods to Maintain Integrity
- Detection & Diagnostics During Well Construction
  - Find & Record SCP Source Zones
  - Unexpected Annular Pressure Traps (low TOC, etc.)
- Mechanical Barriers (sealing devices & tubulars)
- Cementing Barriers (primary & secondary applications)
- Formation Barriers Near the Wellbore
  - Unplanned Casing Seats Across Weak Zones
  - Unexpected Pore Pressures Higher Than Shoe Tests
  - Borehole Integrity Strengthening Methods
- Chemical Sealant Barriers
  - SCP Source Zone Permeability Barriers
  - Annular Chemical Packers

Preventive Practices (cont'd)

- Well Integrity Verification Evaluation and Testing
  - Types of Tests: Casing & Shoe, Liner Lap, Packer, etc.
  - Positive vs. Negative Pressure Tests
  - Casing Pressure Tests Just After Cementing
  - Cement Evaluation Logs (Refer to API 10TR1)

Remedial Well Integrity Practices

- ACP Detection & Diagnostics (Expand RP 90 Sections)
  - Logging Methods to Identify SCP Flow Paths
  - Casing/Liner Caliper & Inspection Logs
  - Gauge Ring Tests
  - Straddle Packer Pressure Tests
  - Downhole Cameras
  - Pressure & Temperature Monitoring by Permanent Downhole Sensors
  - Others (Preventive Practices above)
- Well Integrity Monitoring After Abandonment
- Annular SCP Flow Path Sealing Methods and Materials
- Rock Barriers (Sealing Methods for Permeability, Fissures, Fractures, etc.)
- Cementing Barriers (Squeeze & Plug Cementing)
- Casing/Liner Pipe Repair Methods and Materials

RP 65-3 Appendices:

- Background: API activity on SCP and TIACP
- Case histories, studies & statistics
- Lessons Learned
- Underground storage history: Acid gas, CO_2, natural gas, brines, etc.
- CO_2 injection well applications: miscible vs. immiscible pressure for EOR, EGR, ECBM, etc.
- References
- Definitions
- Etc.

IEA Greenhouse Gas R&D Programme

3rd Well Bore Integrity Network Meeting

12 & 13 March 2007 Santa Fe, New Mexico

"A Review of Injection Well Mechanical Integrity Testing Data and Implications for Geosequestration"

Jonathan Koplos, Chi Ho Sham, and Shari Ring

The Cadmus Group, Inc.

Study Objective

- Draw lessons for CO_2 injection and geosequestration from the Underground Injection Control (UIC) Program's mechanical integrity tests (MITs) of well performance

- Assess the availability and adequacy of data on mechanical integrity testing

Outline

- Introduction – Mechanical Integrity Testing (MIT) and CO_2 injection
- Underground Injection Control (UIC) Program -- Class I and II wells
- Sources and availability/adequacy of MIT information
- MIT failure rates, types, consequences from existing studies
- MIT failure rates from Texas UIC Class II EOR wells
- Conclusions and Discussion Points

Injection Well
Mechanical Integrity

An injection well has Mechanical Integrity (MI) if there is:

- no leakage in the casing, tubing, or packer (internal MI)
- no fluid movement vertically along the outside of the wellbore
(external MI)

Importance of MI for CO_2 Injection

- CO_2 corrosivity can affect well tubing, packers, casing, and cement
  - "*Leakage from the injection well…is one of the most significant potential failure modes for injection projects*" (IPCC, 2005)
  - *Existence of IEA Well Bore Integrity Network (!)*
- Corrosive CO_2 requires design, operation, and risk considerations regarding the mechanical integrity of CO_2 injection wells

UIC Program

- Maintaining MI is the protective cornerstone of the UIC Program
- UIC objective: prevent endangerment to Underground Sources of Drinking Water (USDWs)
- Since the 1980s, the UIC Program has regulated injection of fluids into the subsurface

UIC Class I and II Wells

- Regulations define 5 classes of injection wells
- Class I and II wells are CO_2 injection analogues
  - Class I - long-term storage, high volumes injected
    - Class I Hazardous Waste Injection Wells (no-migration)
    - Florida Class I Municipal Wells (buoyant, treated water)
  - Class II - oil & gas production-related fluids
    - Enhanced Oil/Gas Recovery (EOR/EGR) wells (CO_2)
    - Acid Gas Injection (AGI) wells (CO_2 + H_2S)

UIC Requirements

- Injection wells are subject to requirements for siting, construction, operation, monitoring, MITs, and closure (plugging)
- Class I well requirements are more stringent, especially for wells that inject hazardous waste
- Class II well requirements can be more flexible and varied; SDWA Section 1425 requires that State programs be “effective preventing underground injection which endangers drinking water sources”
- Class I and II wells are required to formally demonstrate MI prior to and throughout injection operations

Class I and II Injection Well MIT and Monitoring Requirements

Well Class	Mechanical Integrity Tests		Other Tests	Monitoring and Reporting Frequency
	Part I (Internal MI)	**Part II (External MI)**		
Class I – Hazardous	Pressure test annually and after each workover	Temperature, noise or other approved log at least every 5 years	Radioactive tracer, pressure fall-off -- *Annually* Casing inspection log -- *After each workover* Corrosion testing -- *Continuous*	Continuous injection press., flow rate, volume, temp., and annulus pressure + fluid chemistry + GW monitoring as needed. -- *Quarterly reporting*
Class I – Non-Hazardous	Pressure test or alternative test at least once every 5 years	Temperature, noise or other approved log at least every 5 years	Pressure fall-off test -- *Annually*	Continuous injection press., flow rate, volume, and annulus pressure + fluid chemistry and yearly pressure fall-off test. -- *Quarterly reporting*
Class II	Pressure test initially and every 5 years for brine disposal wells	Adequate cement records may be used in lieu of logs	Fluid chemistry -- *Annually* Other tests as needed or as required by permit	Injection pressure, flow rate and cumulative volume, observed weekly for disposal and monthly for ER -- *Annual reporting.*

EPA Approved MITs

Tests for internal MI (40 CFR §146.8(b)):

- annulus pressure or annulus monitoring test
- radioactive tracer test
- water-brine interface test
- pressure test with liquid or gas
- monitoring records showing the absence of significant changes in the relationship between pressure and injection flow rate (certain Class II wells only)

Tests for external MI (40 CFR §146.8(c)):

- temperature log
- noise log
- oxygen-activation log indicating lack of fluid migration behind the casing
- radioactive tracer survey indicating lack of fluid migration behind the casing
- cement bond log showing gamma ray, transit time, collar locator and variable density log
- cementing records (in lieu of any tests or logs) that demonstrate the presence of adequate cement to prevent migration of fluids into a USDW (Class II wells only)

Sources of MIT Information – State data

- There is no national database of UIC MIT data
- Many States maintain electronic UIC databases
- State databases may have data on 90 percent of Class II wells
- State data are not nationally compiled, readily accessible, or comparable

Studies of MIT Failure Rates

- A Class I Injection Well Survey (Phase II Report): Survey of Operations *(UIPC, 1987)*

- Hazardous Waste-Controls Over Injection Well Disposal Operations *(GAO, 1987)*

- Class I Well Failure Analysis: 1988-1992. *(USEPA, 1993)*

- Class I Mechanical Integrity Failure Analysis: 1993-1998. *(USEPA, 1999)*

- Analysis of the Rate of and Reasons for Injection Well Mechanical Integrity Test Failure. (Class II wells) *(USEPA, 1993)*

What An MIT Failure Is and Is Not

- MIT failure is a measure of well performance
  - it does not indicate well failure
  - it does not indicate a release to a USDW

Class I MIT Failures: Rates

- Rate of internal MIT failures/active well have declined from:
  - 32% in 1988-1992 to
  - 23% - 28% in 1993-1998

    (proportion of failed tests per active number of wells; not MIT failure rate or percentage of wells with MIT failures)
- Less than 2% of active wells have external MIT failures
- MIT failure rates for hazardous waste injection wells are 2 to 3 times that of non-hazardous waste wells, possibly due to more corrosive injectate

Class I MIT Failures: Types

- Types of internal MIT failures
  - from 1998-1992:
    37% tubing, 21% packer, 17% casing
  - from 1993-1998:
    37-42% tubing, 20-25% packer, 34-23% casing
- Hazardous waste injection wells had slightly higher rates of casing failures than non-hazardous waste wells

Class I MIT Failures: Consequences

- No reported USDW impacts associated with wells with known internal or external MIT failures in the 1988 to 1998 study period
  - ground water observation/monitoring well systems for identifying fluid releases or migration are rare

Class II MIT Failures: Rates

- 1983-1992 study:
  - 10.5% of MITs performed failed

    (percentage of tests that resulted in failures;

    not percent of wells with MIT failures)
  - very incomplete information (data from 4 States)
  - covers period where "grandfathered" older wells were being phased out

Class II MIT Failures: Types

- Only half the records reviewed identified the type of failure

- MIT failure types were:

  54% casing, 25% tubing, 19% packer

Class II MIT Failures: Consequences

- No reported USDW impacts associated with wells with any known internal or external MIT failures in the 1983-1992 period
  - for the wells with casing MIT failures ~25% were plugged within 60 days, suggesting that failures were serious and that well re-working was expensive and not worthwhile
  - ground water observation/monitoring well systems for identifying fluid releases or migration are rare

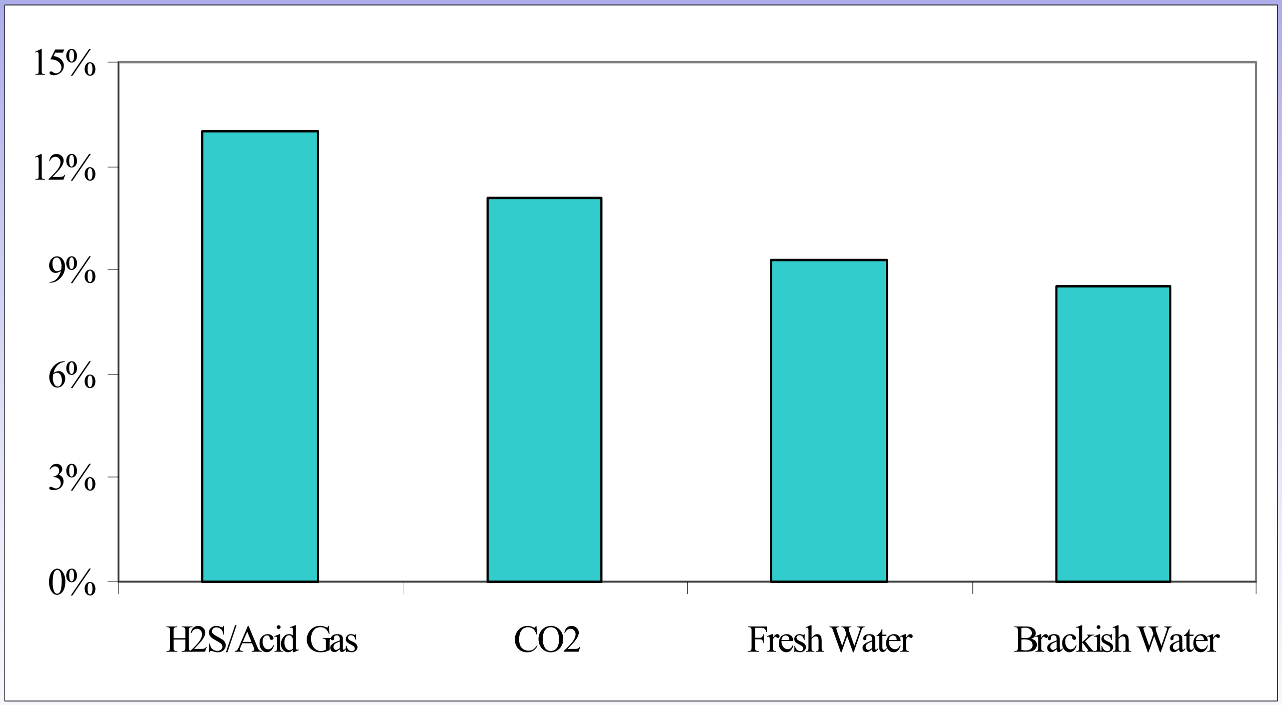
CO_2/EOR Wells in the US: Location, Depth, & General Geology				
State	**# fields**	**# inj wells**	**depth (ft)**	**injection zone**
CO	1	262	6,000	SS
KS	1	3	2,900	LS
MI	3	5	5,400 - 5,500	LS/dolo
MS	6	89	10,300 - 11,000	SS
NM	3	168	4,200 - 4,550	dolo
OK	5	211	6,200 - 9,400	SS
TX	50	3,521	2,680 - 8,000	Mix, mostly LS/dolo
UT	2	130	5,600 - 5,700	dolo/LS
WY	9	215	1,150 - 9,000	Mix, mostly SS
Total	**80**	**4,604**	**1,150 – 11,000**	**LS/dolo & SS**

Summarized from "Oil and Gas Journal," April 17, 2006; Biannual EOR Survey, pg. 48, Table C

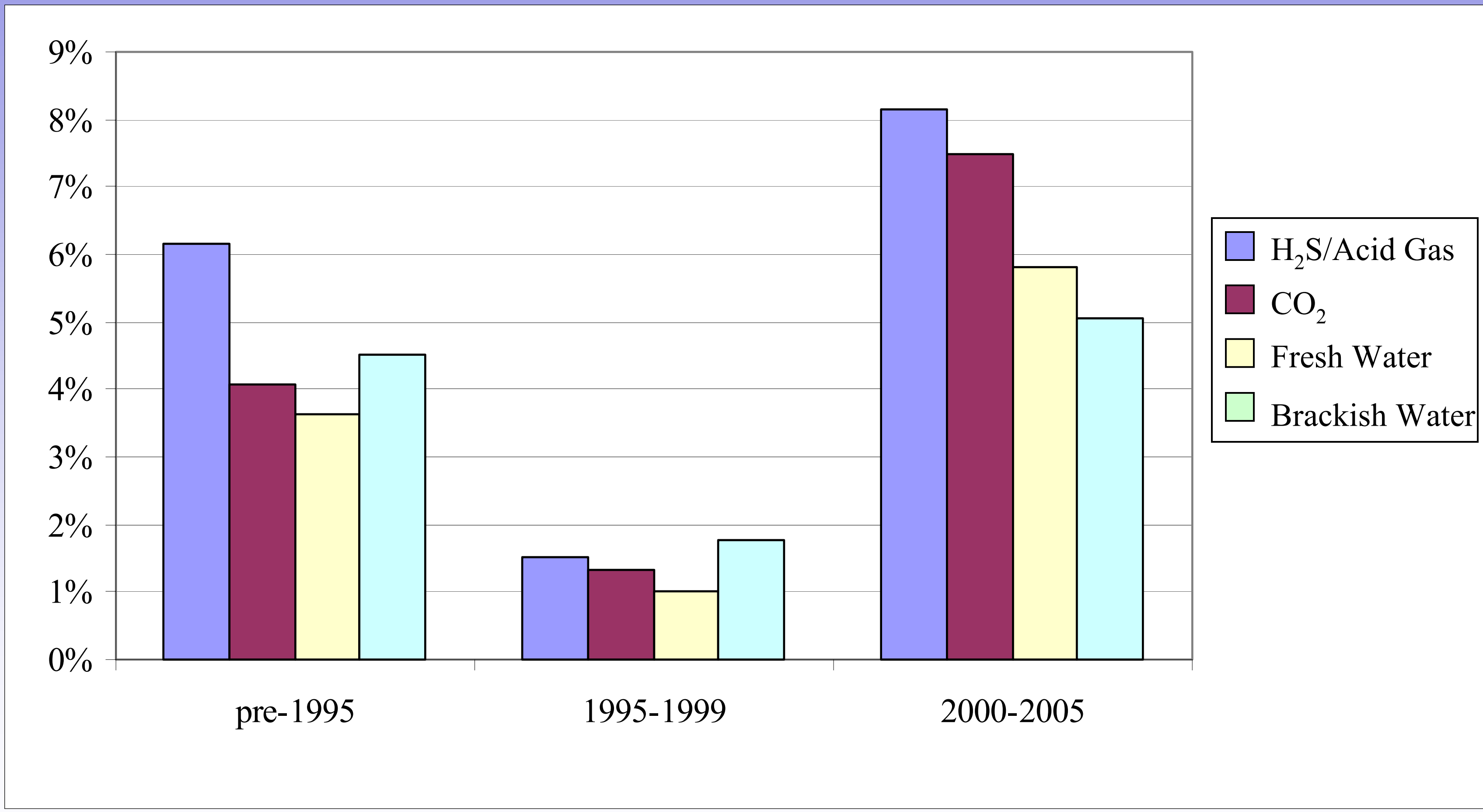
Texas UIC Data - Class II EOR Wells (1983-2005)

Injection Type	Years	Total # of Wells	Total # of Wells with MIT Failure	% Wells with MIT Failure
acid gas	pre-1995	568	35	6.2%
	1995-1999	594	9	1.5%
	2000-2005	748	61	8.2%
	All Years	**752**	**98**	**13.0%**
CO_2	pre-1995	3,324	135	4.1%
	1995-1999	3,432	46	1.3%
	2000-2005	3,978	298	7.5%
	All Years	**4,105**	**455**	**11.1%**
fresh water	pre-1995	5,395	197	3.7%
	1995-1999	5,703	57	1.0%
	2000-2005	6,175	359	5.8%
	All Years	**6,400**	**596**	**9.3%**
brackish water	pre-1995	10,713	483	4.5%
	1995-1999	12,715	223	1.8%
	2000-2005	14,488	731	5.0%
	All Years	**16,060**	**1,366**	**8.5%**

Percent TX Class II EOR Wells with MIT Failures (1983-2005)



Percentage of Active TX EOR Wells with at least one MIT Failure: Trends over Time



Regulatory and Operational/Economic Context

- **1985 – Standardized and fully documented MIT procedures were implemented in TX (MIT failures up)**
- **1990s – The TX MIT program was being refined and expanded**
- **1995 -- 3rd 5-year MIT cycle shows old wells not worth repairing? (MIT failures down?)**
- **1995 – Operators required to post bonds for inactive wells and bring inactive wells into compliance before getting new permits (MIT failures up?)**
- **2000 – Rule change limited the use of TCAM (tubing-casing-annulus monitoring), an alternative to full MIT (MIT failure up?)**
- **1995-1999 – below average oil prices (effect on well use/MIT failures?)**
- **2000-2005 – above average oil prices (effect on well use/MIT failures?)**

Conclusions & Discussions

- A key component of the success of the Class I and Class II injection well programs is maintaining and monitoring injection well mechanical integrity
- Injection well mechanical integrity is a concern for CO_2 injection and storage due to corrosivity of CO_2 (and potential impurities) on injection well materials especially given the very large volumes and very long time frames anticipated for CO_2 geosequestration

Conclusions & Discussions (cont.)

- Although better constructed, EOR wells that inject acid gas and CO_2 have somewhat higher MIT failure rates than EOR wells that inject primarily water
- MIT failure data reflect many influencing factors beyond injectate type (in other words, regulations and economics affect well performance)
- MIT failure rates provide general trends in injection well performance across a variety of regulatory and operational conditions

Conclusions & Discussions (cont.)

- Have any Class II wells that inject CO_2 experienced leakages along the borehole either to the surface, or into USDWs or other formations?
- What well performance data are necessary to support risk assessments or FEP (features, events, and processes) analyses for the development of a management framework for commercial scale CO_2 injection and geosequestration?
- How are the variety of lab, field, and historic well integrity studies synthesized in support of a management framework?

Conclusions & Discussions (cont.)

- How might information from injection well MIT assessments apply to assessments of abandoned wells within proposed CO_2 storage reservoirs?

- What types of well construction and integrity data will be generated during the DOE Pilot Projects?

- Do operational, geological, risk, or other factors suggest a management framework with MIT guidelines or standards? Well construction guidelines or standards?

EPA has published the guidance for using

The Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects

http://www.epa.gov/safewater/uic/wells_sequestration.html

T. L. WATSON & ASSOCIATES INC.

Alberta Oil and Gas Regulations The Key to Wellbore Integrity

Presented by

Theresa Watson

at the

Third Wellbore Integrity Network Meeting

Santa Fe, New Mexico

March 13, 2007

Overview

- Alberta Oil and Gas Wells
- Regulation History
- Regulation Protecting Groundwater and Atmosphere
- Wellbore Construction
- Wellbore Abandonment
- Alberta Advantage
- Skeletons
- What Next?

Oil and Gas Wells in Alberta

End of 2006

362,265 total

116,550 abandoned

Oldest: 1883

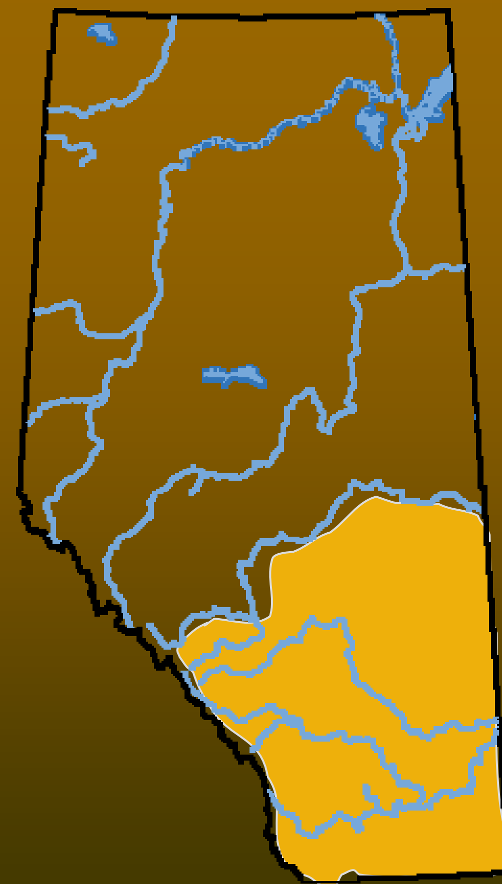
Area: 664,332 km^2
(256,610 sq.mi)

Major Historical Events

- 1670 Hudson Bay Company (HBC) granted most land in Western Canada
- Building the railway
- Federal to provincial ownership of resources

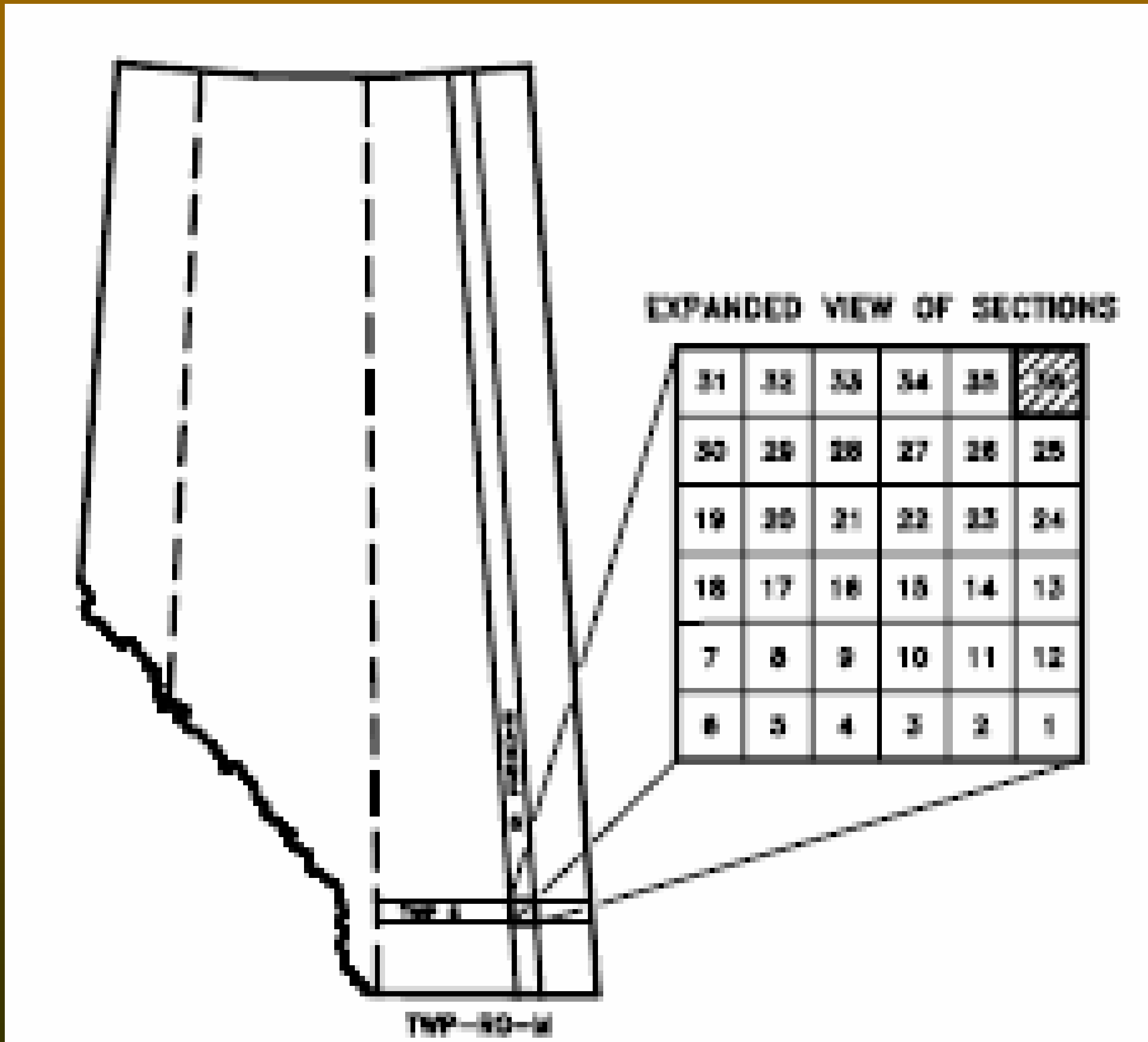
Hudson Bay Company

1870 HBC surrenders land to Dominion of Canada and retains 1/20 of Fertile Valley Land Belt (Bounded by USA border, North Saskatchewan River, Rocky Mountains and Lake Winnipeg) Sections 8 and 26

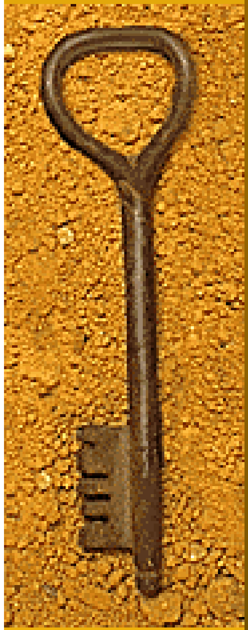


Company eventually formed
Hudson Bay Oil and Gas
Dome Petroleum
Amoco

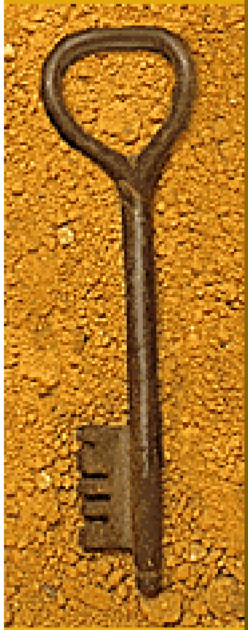
Dominion Land Survey



Canadian Railway



Canadian Pacific Railway (CPR) and other rail companies were granted odd numbered townships except 11 and 29 in exchange for development of the railroad.



CPR Hits Gas

1883 CPR hits gas while drilling for water to supply the steam engines.

Individual Landowners

- The rail companies and HBC sold off some land to individuals, who obtained the mineral rights with their purchase.
- After 1887 mineral rights were not issued with the homestead grants on the remaining 18 sections of a township.
- The government retained ownership of the minerals.

Major Historical Events

- 1922 the Federal Government implements drilling spacing requirements.
- October 1, 1930 the Federal Government turns over mineral ownership to the provinces.
- 1931 Alberta enacts legislation to control drilling activity
- 1932 Turner Valley Conservation Board
- 1938 Alberta Petroleum and Natural Gas Conservation Board (precursor to the EUB)
- 1950 Alberta Oil and Gas Act

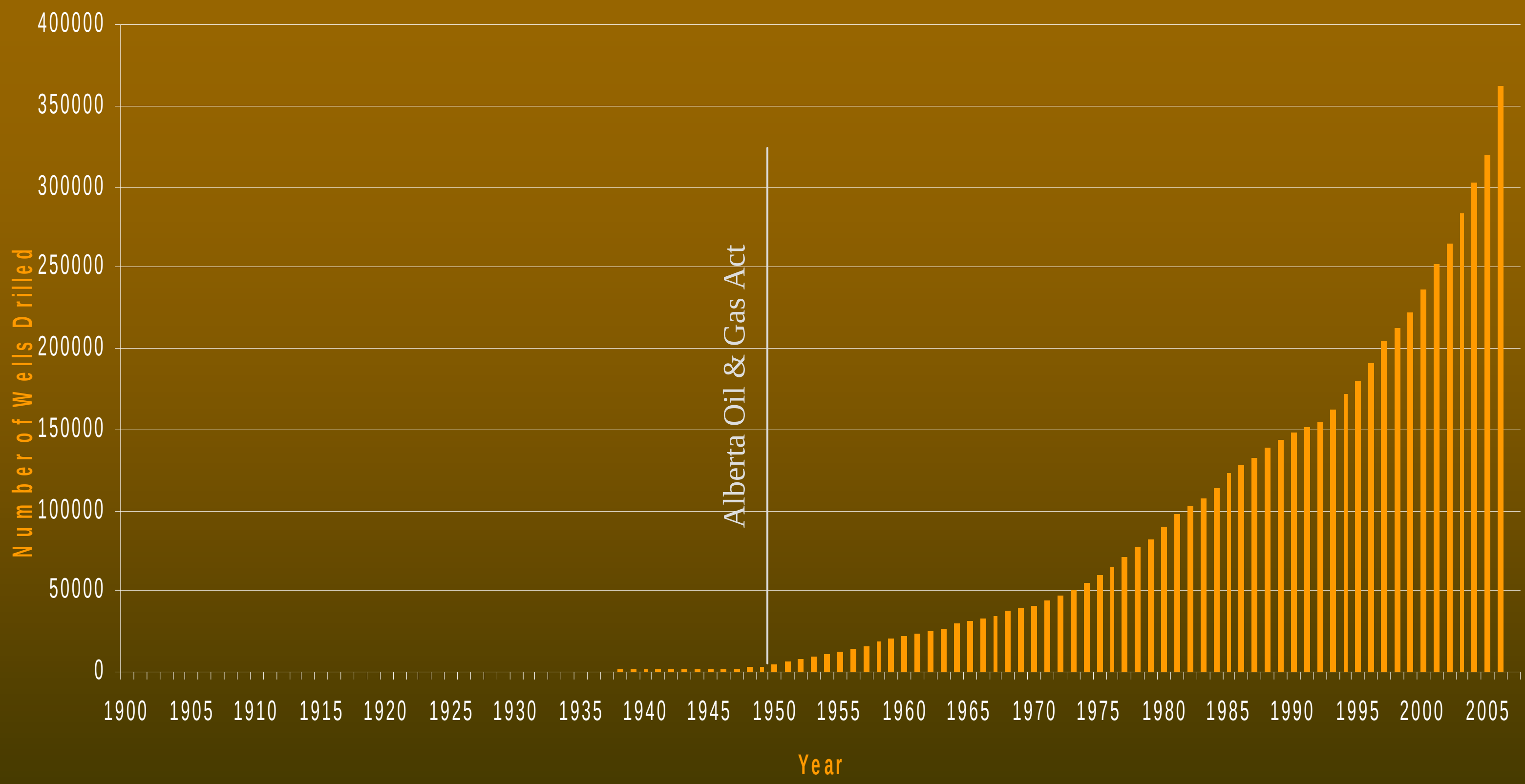
What This Means

- The government had a vested interest in keeping track of any oil and gas activity, for royalty payment.
- HBC and the rail companies also needed good records to make sure they would be adequately compensated.
- From the beginning, licenses were issued and records were kept regarding drilling, completion and abandonment of wells.

Early Drilling Activity

Approximately 850 wells were drilled prior to 1938 in Alberta.
Records for these wells were gathered and retained by the regulator after 1938

Cumulative Wells Drilled

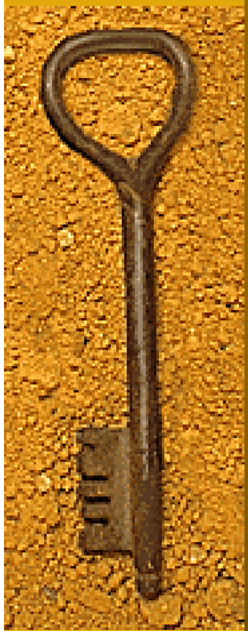


Extensive Data Repository

- Licensing Information
  - Depth, licensee, location, deviation, classification, etc.
- Wellbore Construction
  - Casing, cementing, perforating, equipment, dates
- Geology
- Production
  - Gas analysis, reserves, volumes, water, allowables, etc.
- Abandonment
  - Dates, method, surface casing vent flow and gas migration, pressure test, surface abandonment.

Regulations Impacting Wellbore Construction & Abandonment After the Implementation of the Alberta Oil and Gas Act in 1950

1. Oil and Gas Act
2. First SC requirements
3. First cement requirements
4. Update of SC requirements
5. Update of SC and cementing requirements
6. Intermediate casing
7. Conductor pipe requirements
8. Update of SC requirements for SE Alberta
9. Update of SC requirements for south-central Alberta
10. Cementing guide
11. Update of cementing guide
12. Requirements for GW protection and SCVF checking
13. 10-year inactive well program initiated
14. Well abandonment guide, sour well licensing
15. Requirements for SCVF/GM testing
16. Long Term Liability program replaces 10-year inactive well program
17. Update of allowable gradient for serious SCVF



Original Oil and Gas Act

- Provisions to notify and obtain approval to drill or abandon a well
- Required proper casing and cementing
- Conservation of gas, oil and water
- Protection of life, property and wild life
- Prevention of fire
- Prevention of well blow out
- Prevention of pollution of fresh water supplies

Historical Protection of Groundwater

- Oil and Gas Act of 1949 required
  - Surface casing be cemented full length
  - Next string of casing to be cemented in compliance
  - Annulus between casings to be left open
  - Water encountered while drilling must be reported.
- 1967 Surface casing must be set 75 ft below potable water (no definition of potable)
- Injection wells must be equipped with a packer.

Protection of Atmosphere

- Main concern is Hydrogen Sulfide leakage
  - Wells with over 5% H_2S must be equipped with packers
- Natural gas leaks to atmosphere were implicated in atmospheric pollution later on.
  - Regulation regarding venting and flaring has been evolving since 1995

1990's

- Major regulation changes started occurring about this time.
- Suspension guidelines (ID 90-04)
- Specific abandonment requirements (Guide 20, 1991)
- Requirements to test wells for leakage prior to abandonment. (ID 95-01)
- Requirements for repair of leaking wells if serious or prior to abandonment. (Guide 20)
- Useable groundwater defined as <4000 mg/l TDS
- Protection of useable groundwater specifically required during well construction and abandonment. (Guide 20)

Wellbore Construction

- 1963 minimum surface casing cementing requirements
  - Last updated 1997
- 1966 minimum production and intermediated casing cementing requirements
  - Last updated 1990
- 1990 casing design requirements
  - Update in progress

Testing & Reporting Requirements

- 1989 Casing failure (ID 89-19)
  - Updated 2003
- 1989 Packer isolation testing (ID 89-09)
  - Updated 2003
- 1990 Segregation tests (ID 90-03)
  - Updated 2006
- 1995 Surface casing vent flow testing
  - Updated 2003

Abandonment

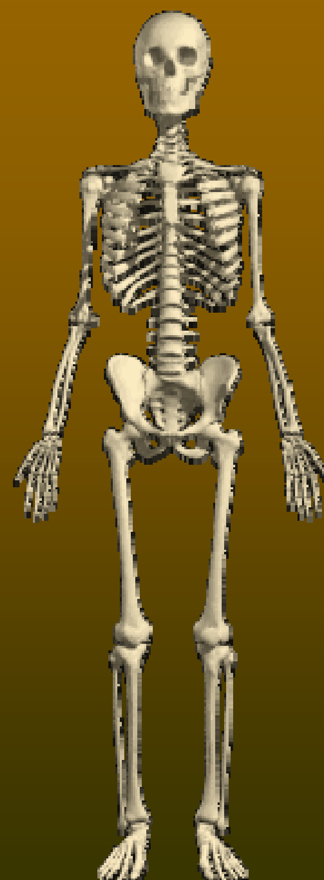
- First comprehensive guide issued in 1991
  - Current issue 2004
- Specified porosity cutoffs for plug setting in open hole abandonment
- Specific requirements for wells penetrating bitumen reserves
- Plug setting requirements for cased hole
- SCVF/GM testing requirements
- Pressure testing requirements
- Zonal isolation requirements
- Ground water protection requirements
- Surface abandonment requirements

Alberta Advantage

1. Alberta has excellent historical records of wellbore location, construction and depths.
2. Regulation has historically been strong in ensuring wellbore integrity, both for resource management, depletion and public/environmental protection
3. We know where we've been.
4. We know where the skeletons lie.

Skeletons in the Closet

- Regulations were developed for the depletion of the resource in a safe and equitable manner.
- Technology changes redefine "resource"
  - Coal bed methane
  - Tight gas sands
  - Shales
  - Hydrates
- Changes in reservoir uses
  - CO_2 storage
  - EOR projects
  - Acid gas storage
  - Nuclear waste storage
- Testing and reporting requirements
- Cased hole abandonment methods
- Surface abandonment methods



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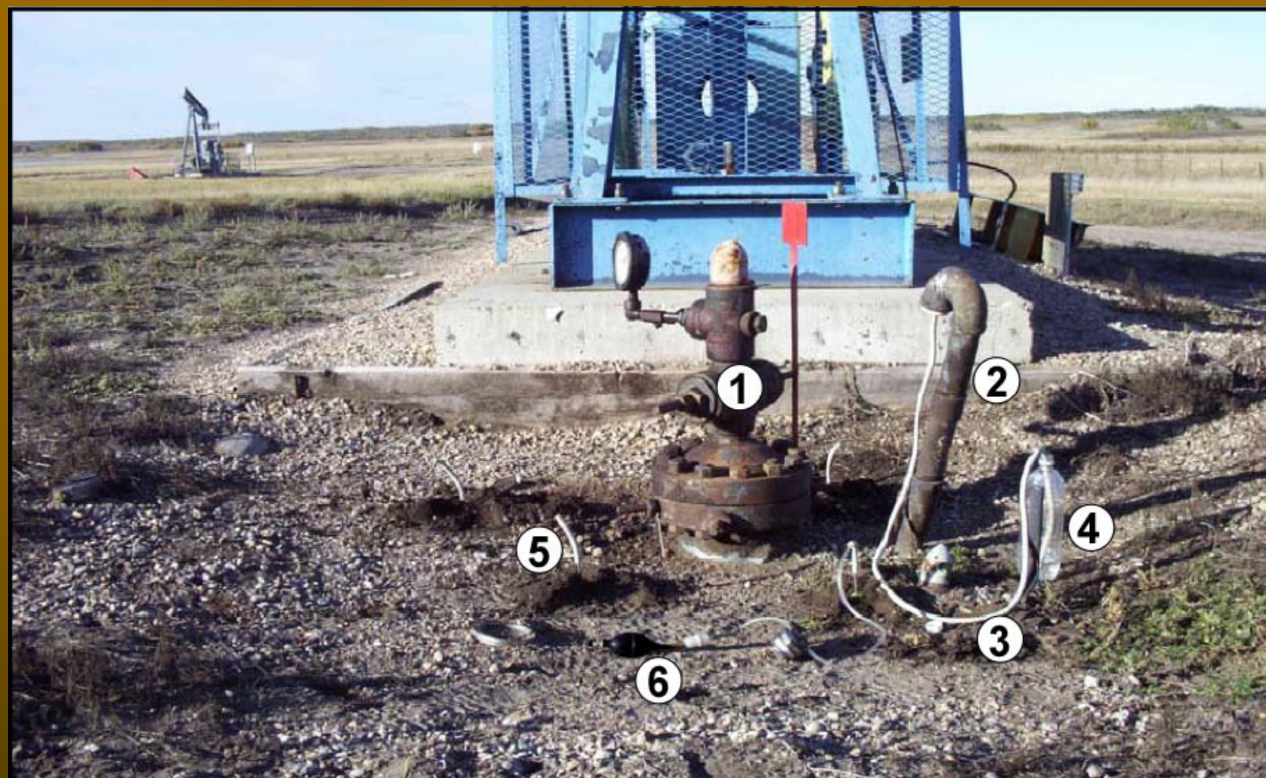
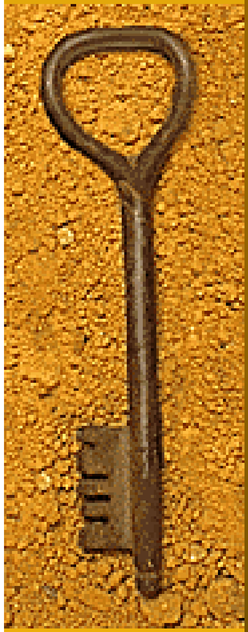
Example of SCVF and GM Testing

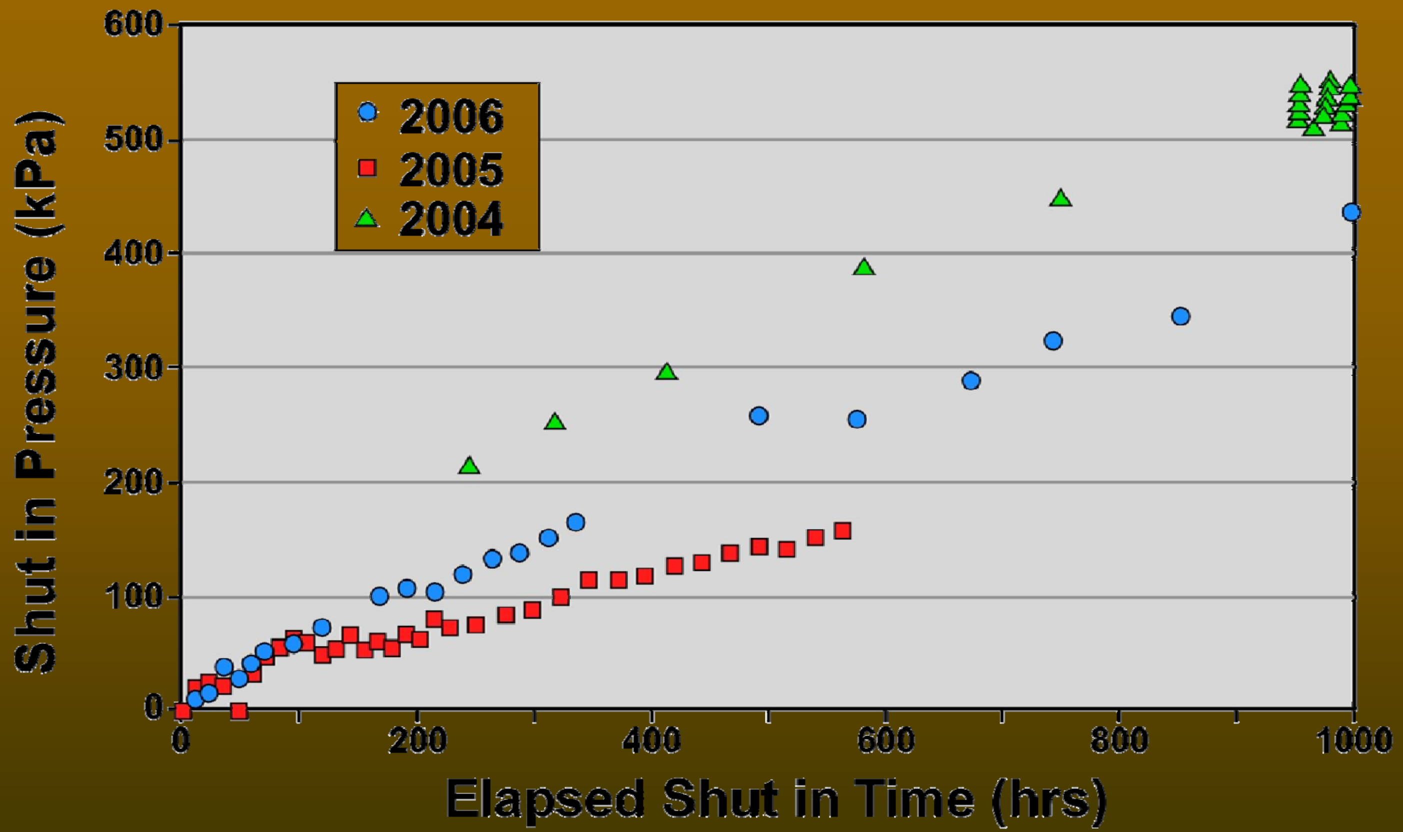


1: Wellhead
2: Surface casing vent (SCV)
3: Hose connected to SCV to direct flow

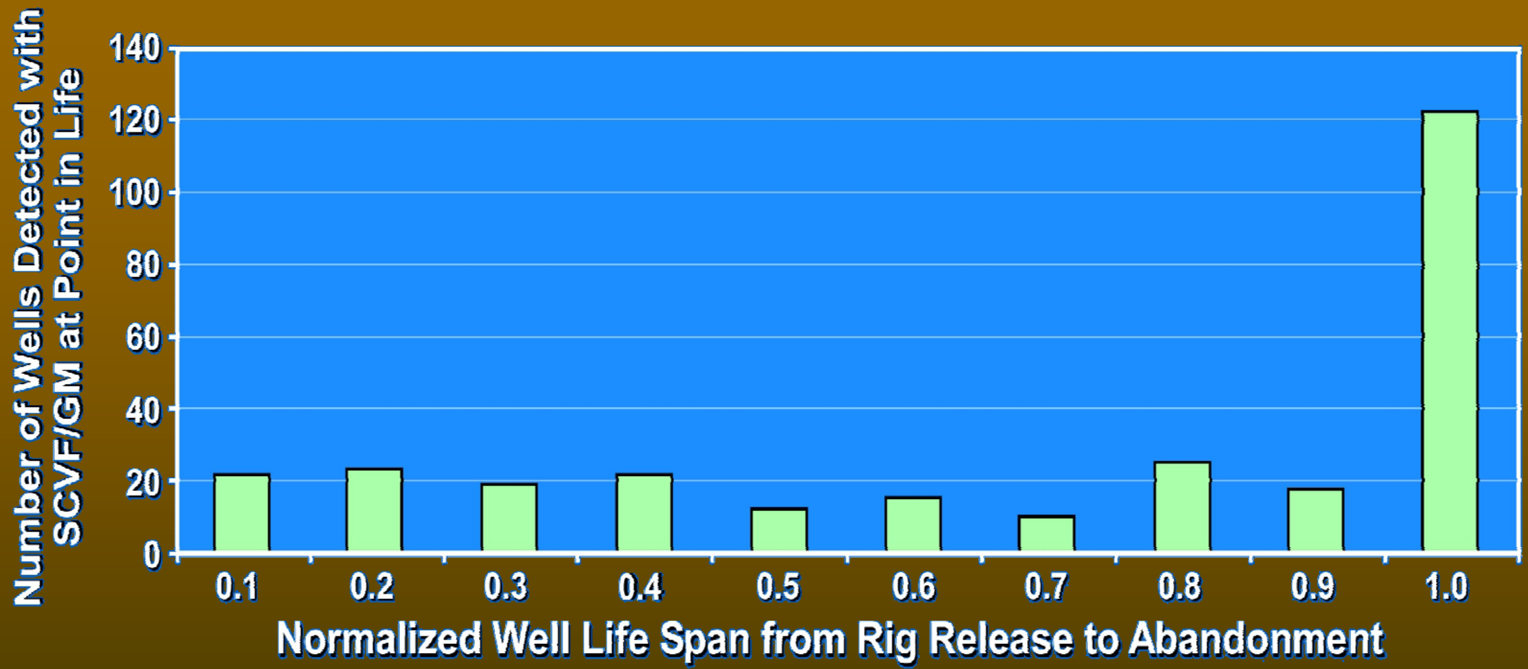
4: Container with water to observe gas bubbles
5: Gas migration test hole
6: Hand pump to direct the accumulated gas to the LEL meter (LEL: Lower Explosion Limit)

Annual Pressure Build-up Tests for SCVF in a Well which Passed the Bubble Test

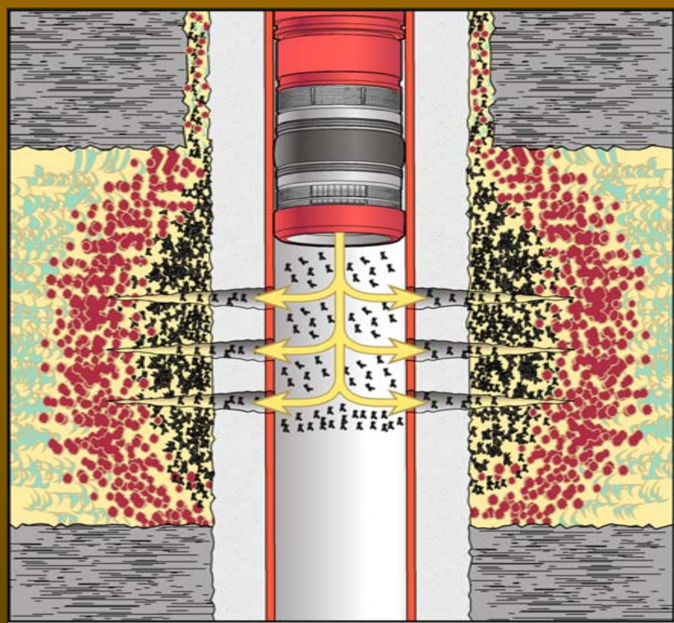


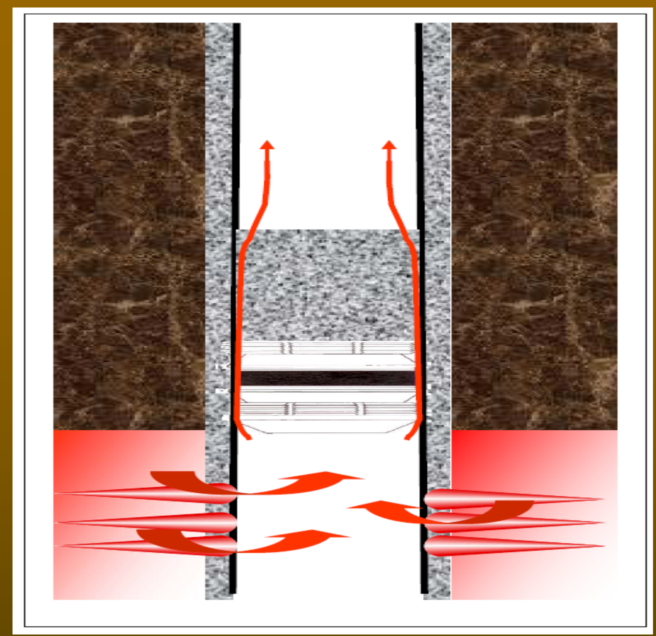


Time to Detect SCVF/GM



Cased Hole Abandonment Methods

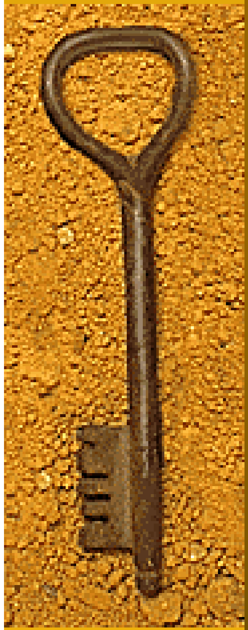


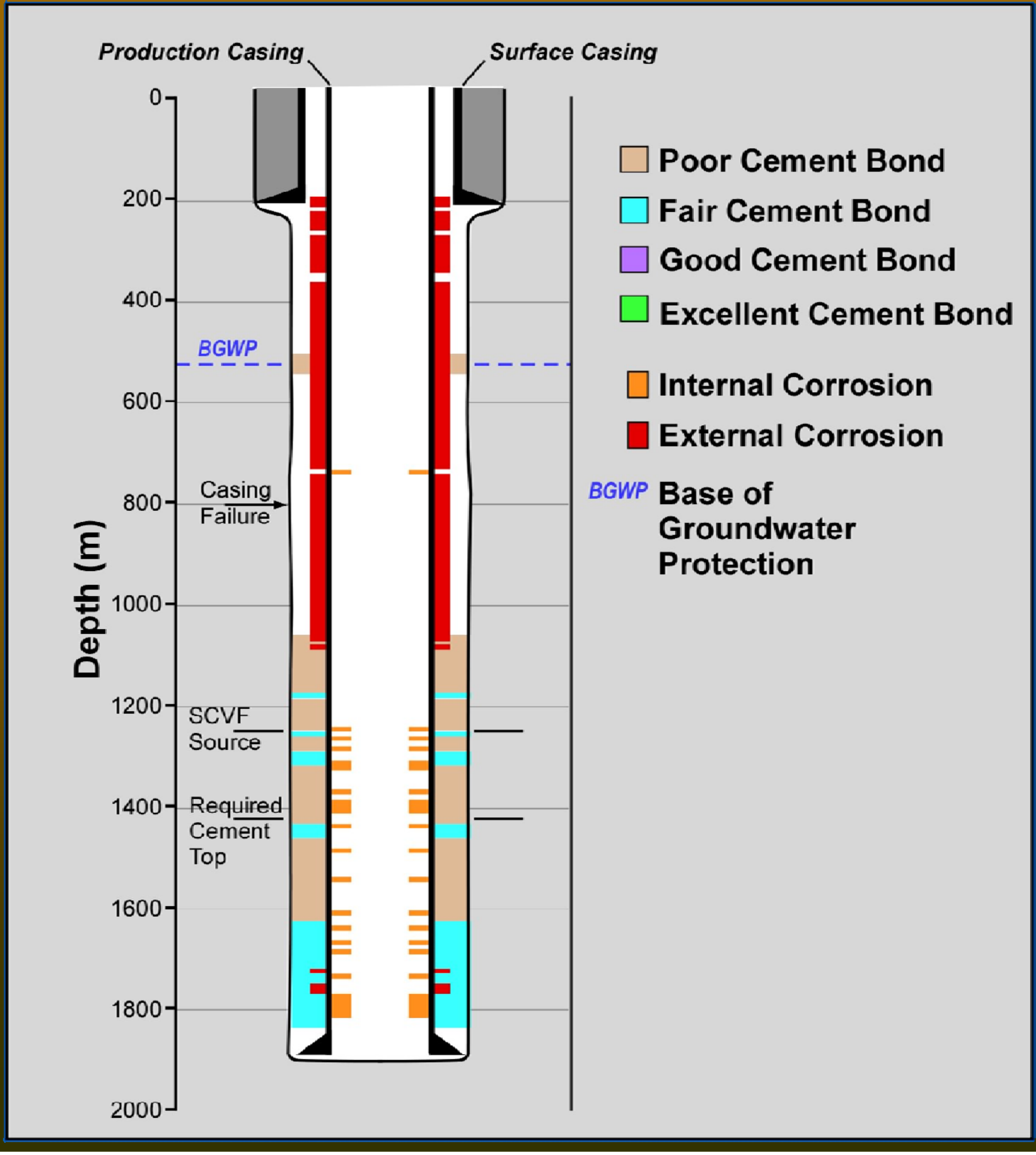


Most secure method of cased hole abandonment:
Cement retainer and squeeze cement to seal sand face, perforations and wellbore.

Typical zonal abandonment:
Bridge plug capped with cement. Reservoir fluids can attack metal and elastomers and eventually leak to surface.

Example of Cement and Casing Quality in a Well in the Haynes Field, Alberta





Casing Failure

Installation of Surface Abandonment Caps

Capping production casing

Capping surface casing

Surface Abandonment Issues

- Undetected wellbore leakage or failure of zonal abandonment can lead to high pressures beneath the well cap.
- In conjunction with casing failure gas or fluid may breach the surface casing shoe and/or infiltrate ground water
- High contained pressure in wellbores poses a public safety risk in the event of accidental strikes
- Practice of placing corrosion inhibitors in the wellbore may place ground water at risk if casing fails.

Where Do We Go From Here?

- Work is ongoing to amend regulations going forward to address future use of reservoirs and wellbores
- Changes in surface abandonment requirements
- Discussions regarding zonal abandonment methods and products
- Well inhibition after abandonment
- Cementing requirements
- Industry proactive on many issues
- Alberta’s Advantage in information will provide the means to identify and rectify future problems

Alberta is looking forward to a bright future, where…….

Life is good!!