2nd Well Bore Integrity Workshop

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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 international research network on Well Bore Integrity is organised by IEA Greenhouse Gas R&D Programme in co-operation with BP. The organisers acknowledge the financial support provided by EPRI and CMI for this meeting and the hospitality provided by the hosts Princeton University.

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)
Bill Carey, LANL
Mike Celia, Princeton
Darryl Kellingray, BP
Rick Chalaturnyk, University of Calgary
Idar Akervoll, Sintef
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Summary Report of

2nd Well Bore Integrity Network Meeting

Date: 28– 29 March 2006
Princeton University,
New Jersey, USA

Organised by IEA GHG, BP and Princeton University
with the support of EPRI

INTERNATIONAL RESEARCH NETWORK ON WELL BORE INTEGRITY

SECOND WORKSHOP
Princeton, New Jersey, USA

Executive Summary

The second meeting of this Network was held in Princeton, New Jersey, USA in March 2006. The meeting was again well attended and as well as research groups attracted a considerable number of industry experts who have direct experience with well operations.

There were a number of reports that indicated that well integrity may be a current issue within the oil and gas industry. A detailed study on production wells in the Gulf of Mexico indicated that up to 60% of wells had casing pressure problems, which could indicate that the integrity of the wells had been compromised. Experience from the Permian basin in the USA indicated that when fields were changed over to CO_2 flood that significant remedial work was needed to pull and re cement wells that had not seen exposure to CO_2. It was considered that many of the problems in both the Gulf of Mexico and the Permian basin resulted from poor well completions at the outset. This may be due to cases where the casings were not cleaned properly prior to CO_2 injection and the presence of residual mud in the wells led to poor seals between the cement and the formation and the cement and the casing liner (steel). Similar issues could arise due to too rapid curing of the cement, or poor cement squeezing. Where poor seals occur ingress of saline water from overlying aquifers can results in chlorine induced corrosion of the steel casing liner. The API has recognised this as a major problem and in response it is developing a new set of standards for well completions. A further set of standards for wells in CO_2 floods us also being developed but this is at an early stage.

Laboratory experiments on Portland cement samples have indicated that the integrity of the cement is rapidly decreased in the presence of CO_2 due to chemical reaction. However, when the laboratory samples are compared with samples of cement taken from a well at SACROC (a CO_2 flood in the Permian basin in the USA) whilst some cement degradation is observed it is not as severe as in the laboratory experiments. The conclusion is that the laboratory experiments maybe designed incorrectly (i.e., the conditions are not comparable to field conditions) and may be over exaggerating the problem. Schlumberger have designed a new cement that is resistant to CO_2 attack under laboratory conditions. Whilst the industry people welcome this development, they suggest its higher cost may prohibit its use and they have concerns that it may have other properties that may mean that it seals less effectively in the well casing.

A number of groups including the CCP2 and Weyburn are developing field experiments to monitor CO_2 degradation in the field in individual wells. The results of these experiments, although several years away, are eagerly awaited.

SECOND WORKSHOP OF THE INTERNATIONAL RESEARCH NETWORK ON WELL BORE INTEGRITY

1. Introduction

A number of the risk assessment studies completed to date have identified the integrity of well bores, in particular their long-term ability to retain CO_2, as a significant potential risk for the long-term security of geological storage facilities. To assess how just how big an issue well bore integrity is, a workshop was held in April 2005 to bring together over 50 experts from both industrial operators and from research organisations[1]. The workshop identified that ensuring well integrity over long timescales (100's to 1000's tears) has not been attempted before and therefore represents a new challenge to the oil and gas industry. One conclusion from the workshop was that it will probably not be possible to promise a leak-free well since it is well known that conventional Portland cements are degraded by CO_2. Rather, the emphasis should be on designing wells employing state-of-the-art technology which should reduce the risk of CO_2 release. It is unfortunate that some of the most desirable potential storage sites are hydrocarbon fields, which are proven traps and have the economic potential for tertiary enhanced recovery. However, these same sites are also penetrated by numerous wells which could be susceptible to erosion/corrosion. The effectiveness of CO_2 storage at such sites may, therefore, not be as high as originally thought.

The inaugural workshop of the network clearly identified that well bore integrity was a key issue which needed to be addressed further. A number of issues were identified which were:

- The frequency of failure. It was concluded that little data was available from oil and gas operations that enabled failure frequency estimates to be made. This was due to several reasons including commercial sensitivity and inconsistent definitions of failure. However, some estimates could be made; for example if failure was defined as loss of fluids to the surface, then it was suggested that perhaps 1 in 100000 wells may fail in this way. One possible way to obtain information on frequencies would be to approach regulators.
- The mechanism of failure. Several mechanisms have been suggested during the meeting but little is currently known about detailed processes on the small scale that lead ultimately to leakage.
- The consequences of failure. These could be very different depending on rate of CO_2 loss, total amount lost, location of well (populated, onshore, offshore, agricultural land etc).

One of the main conclusions from the meeting was the clear need to establish a research network on well integrity issues to consider such activities further. It was therefore agreed to form an international research network under the auspices of the IEA Greenhouse Gas R&D Programme. The aim of the network was to further our

[1] A report from this workshop has been published. The report is entitled IEA Greenhouse Gas R&D Programme, Report No 2005/12, Well bore Integrity workshop, October 2005.

understanding on the issue of well bore integrity in general and begin to attempt develop answers to the main issues identified. This report provides a summary of the second meeting hosted by Princeton University at the University Campus in Princeton, New Jersey, USA between 28th and 29th March 2006.

2. Network Aims and Objectives of Second Workshop

The international research network on well bore integrity has been established with a five year tenure to achieve its aims. The principal aim of the network is to address the three key issues related to well bore integrity with the objective of: providing confidence for stakeholders that the mechanisms of well bore integrity are understood, that the safety of storage in relation to well bores can be assured because the risks can be identified and that the well bores can be monitored and it is possible to successfully remediate a leak should one occur.

The network set itself the goal of addressing the three key issues which are:

- Understanding the problem – There are a number of laboratory based activities that are currently underway but results are yet far from complete. We need to develop our knowledge of they key problems that lead to well failure.
- Monitoring wells – Procedures for testing cements and a protocol for well bore Integrity monitoring need to be established.
- Remediating leaks if they arise – this is essential to demonstrate that if well failures do occur they can be remediated quickly and with little impact on operator safety and the local environment

The main aim of the second workshop was to focus on developing our understanding of the problem.

3. Workshop Programme and attendees

An agenda was developed (see Table 1) that was designed to produce the following outcomes:

- Review of the current state of knowledge of field based statistics ,
- Clarify the current status of laboratory investigations,•
- Follow industry experience in the development of resistant cements,•
- Summarise current experiences of modelling well bore integrity,•
- Identify existing remediation techniques,
- Introduce planned well bore integrity projects.

Brief reviews of the state of the art were given by invited speakers followed by discussions of relevant points, issues and way forward.

Table 1 – Workshop Agenda

Day 1	
Session 1. Introduction	
Welcome/ Safety/ Context	Charles Christopher, BP, John Gale IEA GHG, Mike Celia Princeton
Session 2. Studies of Well Bore Integrity	
K12-B CO_2 Injection Site	TNO – Frank Mulders
North Estes Field in Texas	Chevron – Mike Powers
Weyburn Well Study	University of Alberta - Rick Chalaturnyk
MMS Studies on Wells	BP – Walter Crow
API Activity including Sustained Casing Pressure and Field and Regional Area Studies.	Halliburton – Ron Sweatman
Session 3. Field Experiences **Chair: Daryl Kellingray, BP**	
Introduction/Remediation of Wells with Sustained Casing Pressure	Daryl Kellingray, BP
Advanced Wireline Logging Techniques for Well Integrity Assessment	Schlumberger – Yvonnick Vrignaud
Repairing Wells with Sustained Casing Pressure	CSI – Fred Sabins
Dealing with Wells with Poor Annular Integrity	BP – Jo Anders *Teleconference from Alaska*
Session 4. Laboratory Studies of CO2 - Cement Reactions **Chair: Bill Carey, LANL**	
Corrosion of Cement in Simulated Limestone and Sandstone Formations.	Princeton – George Scherer
Core-flood and Batch Experiments on Carbonation of Casing-Cement-Shale Composites.	LANL – Marcus Wigand
Quantifying CO_2-related Alteration of Portland cement: experimental approach and microscopic methodology.	Schlumberger – Gaetan Rimmele

Table 1 – Workshop Agenda, cont'd

Day 2	
Degradation of Well Cement Under Geologic Sequestration Conditions.	NETL – Barbara Kutchko
Resistant Cement for CO_2 storage Process.	Schlumberger – Veronique Barlet - Gouedard
Session 5. Modelling Well Bore Integrity Chair: Mike Celia, Princeton University	
Reactive Transport Modelling of Cement-Brine-CO_2 systems: Application to SACROC	LANL – Bill Carey
Recent developments for a geochemical code to assess cement reactivity in CO_2/brine mixtures	Princeton – Jean Prevost
Effect of Well Operations and Downhole Conditions on Cement Sheath	Halliburton – Kris Ravi
A Large-scale Modelling Tool for Leakage Estimation and Risk Assessment	Princeton - Mike Celia
CO_2 Storage Well bore Integrity Field Study: A CCP2 Proposal	Chevron - Scott Imbus
Session 6. Breakout Sessions - Ensuring Well Bore Integrity in the Presence of CO2	
Introduction to Breakout Sessions	
Reports from Breakout Sessions and Discussion	
Session 7. Summary, Discussion and Close Chair: Charles Christopher, BP	
Concluding discussions, next steps and proposals for next meeting	
End of Meeting	

The workshop was attended by some 57 delegates. An attendance list for the second meeting is given in Appendix 1 for reference.

4. Results and Discussion

4.1 Technical Presentations

The workshop was structured into 4 sessions of technical presentations; the results of each of these sessions are summarized in the following text.

4.1.1 Studies on well bore integrity

Walter Crow of BP presented an overview of a study commissioned by the Mineral Management Service[2] (MMS) in 2001 that reviewed data on sustained casing pressures (SCP), in wells 8100 wells in the Gulf of Mexico[3]. The study showed that problems of sustained casing pressure are widespread in the Gulf of Mexico (both on and offshore) with up to 60 to 70% of wells affected. The pressure behind the casing cannot be bled off. Note: these wells have not seen CO_2 rather they are natural gas production wells. Gas flow through the cement matrix is believed to be the main cause of SCP. Causes include gas flow through unset cement and due to cement shrinkage after completion – the latter factor is thought to be a major contributor. Surveillance options for SCP appear to be limited. Remediation by injecting high density brine in the annulus has been attempted with limited success, another approach tried has been to pump high density fluid into the casing but the approach cannot be used in deep wells. The best form of remediation is considered to be elimination of the problem in the first place which would be consistent with the goal of containment for CO_2.

> *Questions* asked included whether in the light of these results MMS had changed any of their protocols, the answer was no. Other questions focused on what could be the contributory issues, one was felt to be poor mud removal which could lead to gas channeling another was poor cement curing which could lead to poor bonding between the cement and the rock and the cement and the tubing. Overall, it was considered that improved operational practice was needed to overcome this problem. It was noted that in practice leakage is often observed after pressure tests are undertaken. Well pressure tests are standard procedure for wells to be accepted by MMS, but this procedure could be a source of SCP problems. Various ways of overcoming these problems were proposed for instance; the use of foam based cements could be a way of overcome cement shrinkage. Finally, the comment was made that even if you use the best cement in the world you need to get everything right in the well first – then you use the best cement for the formation.

Ron Sweatman from the API[4] reviewed new practices that they intended to introduce to isolate flow zones. The API activity was stimulated by the results of the MMS study. Statistics from field operations in the Gulf of Mexico indicated that 56% of incidents that lead to a loss of well control were linked to cementing operations. Further some 45% of some 14,927 operational wells in 2004 had SCP problems and

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[2] The Mineral Management Service in Louisiana is the regulatory body responsible for oil and gas and mineral extraction.

[3] The study was undertaken by Louisiana State University for the Mineral Management Service.

[4] American Petroleum Institute

about 33% of the SCP problems were linked to the cementing process. It was noted that in the Gulf of Mexico the leaks are mostly contained and can be remediated, however in Russia where similar problems exist the leaks are not contained. Cementing problems that could cause SCP were:

- Micro annuli caused by casing contraction and/or expansion,
- Channels caused by improper mud removal prior to and during cementing,
- Lost circulation of cement into fractured formations during cementing
- Flow after cementing by failure to maintain an overbalance pressure,
- Mud cake leaks,
- Tensile cracks in cement caused by temperature and pressure cycles.

In API's experience it is not just the cementing process that causes the problem, for instance residual mud in a well may cause problems because it can degrade and cause flow paths. Mud channels are considered to be a serious cause of failure and good mud removal practices are essential to well integrity. Several other root causes listed above may also impair cement sealing in the well annulus between casing and the borehole.

API had now produced a set of standards incorporating best practice and lessons learned to reduce these incidents, API RP-65 part 1 was published in 2001. Part 2 that deals with loss of well control is now out to review and Part three that deals with SCP is under development. Part 3 addresses issues relating to gas containment whether it's CO_2, H_2S or hydrocarbons. Part 2 will help enforce better drilling and well design practices as well as aiming to improve cementing practices. The API RP-65 publications are destined to become U.S.A. federal regulations by the MMS rule making process and will require operators to consider RP-65 in his drilling plan to get a permit and will also require them to provide data on why they intend to deviate from it. Part 3 will reinforce zone isolation requirements to prevent and thus remediate casing pressure problems. The International Standards Organization is considering adopting API -65 as ISO standard practice.

One promising idea for old hydrocarbon fields that may allow them to become economic and effective candidate sites for CCS projects is based on well integrity testing and remediation technology. This process utilizes proven oilfield technology to locate potential leak paths and/or potentially corrosive zones in order to apply sealing fluid treatments such as deep penetrating water-like sealants that convert over time into effective pressure barriers inside the rock formations surrounding the well bore. The API plans to study the successful well integrity remediation case histories in oil and gas well operations to help develop a set of standards for the process in RP-65 Part 3.

> *The key question* asked was how these rules would be extended to CO_2 geological storage, where there could be thousands of wells which require sealing for 100's of years. Ron replied that for initial operations there will be a need for extensive, monitoring and surveillance until they have the data to set design criteria. He felt that CO_2 could be contained by wells with improved practice and there were ways to remediate wells should they leak.

Michael Power of Chevron reviewed experiences from converting a mature oil field in West Texas[5] in 1990 to CO_2 injection. The field was discovered in 1929 and was converted from primary production to water flood in 1950's. Some 165 wells had to be modified in Phase 1 of the CO_2 flood. Four different types of well were encountered, but roughly half were open hole injectors[6] and the other half were cased hole injectors with an average depth of 2750 feet (1250m). Typically the casing extended down to 600 feet (~200m) to isolate any surface sand bodies. There are corrosive aquifer bodies at depths between 700 and 1500 feet (250m to 700m). Of these wells 96 were cleaned out, most had metal liners but some had fibre glass liners. The majority of the fibre glass liners were recovered, whereas only 2% of the metal liners were totally recovered and less than half were partially recovered. All the metal liners showed extensive corrosion below the upper casing layer and this was before CO_2 injection had occurred. The corrosion was considered to be due to chlorine based attack from the brine layers lying at 250 to 700m depth. In re-establishing the wells every effort was made to run a new liner because the costs were considerably less than drilling a new well ($50,000 compared to $225,000 at 1990 prices). All wells were washed out with brine first to ensure good completions were achieved. Mike emphasized that cement squeezing is an art not a science. The personnel on site have a big impact on the success rate for completions. The better trained they are the better the well performance. Of the wells they re-completed about 84% had no leaks the others needed further cements squeezes to be sealed effectively and an acceptable pressure fall off test completed. On reflection, he felt that if all the wells had been cemented from the surface downwards then they would have had a better chance of reusing them. It was noted that personnel need to be aware of the issues of handling CO_2. For instance freezing can occur when lines are blown down and ice plugs can form that can trap pressure.

Comments - Mike closed by saying that before Chevron sold the field they plugged all the old wells, to reduce any future liability. Rick Chalaturnyk made the point that this work showed that we should not underestimate the effort needed to reconvert old oil fields to CO_2 storage.

Well integrity studies at the Weyburn field were reviewed by Rick Chalturnyk from the University of Calgary. As part of the Weyburn Phase I project a database of wells on the Weyburn field has been developed. Operations at the Weyburn field go back to the 1950's and in Saskatchewan records of these operations and the wells drilled are kept by the state government. This should make it easy to build a historical data base that can be related to well operational history. However many of these records leave something to be desired and it was found to be difficult in many cases to populate the data base with the required detailed for many wells. For instance between 1956 and 1961 126 wells were drilled at Weyburn , however for nearly one quarter of the wells the types of drilling slurry used cannot be discerned from the records. Between 1966 and 1967 a further 6 wells were drilled and again 50% of the records are incomplete. The work in Phase I focused on getting as much data as possible into the database which has involved inputting statistics on 100's of wells. Data on failure modes is limited; other work indicates that the main failure mode for wells is cement micro annulus leaks. At Weyburn all the CO_2 injection wells were

[5] The field concerned was the North Ward Estes Field in Ward County, Texas.
[6] Many of the open hole completions were stimulated by dropping nitro-glycerine down the holes to fracture the rock.

cemented to the surface, typically these were class G cements with 2% calcium chloride. There are many abandoned wells will have a cement plug in them but are not cemented to the surface. In Saskatchewan, production wells are not cemented through the cap rock, this is a cost issue not a safety one. In the Weyburn final phase they are developing an analytical model to enable them to predict ph changes and the effect of acid attack on well integrity. The final phase will also aim to undertake some verification work on the data base and compare with field experiments to determine well failure predictions.

Questions addressed the issue of CO_2 breakthrough at the producers since these are not fully cemented through to the cap rock it was felt these were a likely pathway for CO_2 escape. Rick felt this was an issue but at Weyburn there are multiple cap rocks and multiple overlying aquifers so leakage was unlikely to be observed. One issue raised was if there was a protocol for well abandonment in Saskatchewan, which there was. Rick also added that there are several wells due for abandonment at Weyburn and they hope to sample these in the Final Phase.

Frans Mulders of TNO presented results from a study on a CO_2 injection well at the K-12B gas field in the Dutch sector of the North Sea. The well, which was formerly a gas production well, was reconfigured as a CO_2 injector in February 2005. The injected CO_2 is dried prior to injection, water concentrations are at parts per million (ppm) levels. The reservoir temperature is 127^{O}c, the gas contained 13% CO_2 and the produced water 190,000 ppm chlorides which are harsh conditions for a stainless steel well. The well is deviated and has two "dog legs" in it. After one year of injection a caliper analysis was conducted on the well to assess the condition of the production tubing. The inspection showed that pitting of the well had occurred at a depth of around 7000 to 8000 feet (3181m to 3636m). The pit depth was significant and suggests about 25% of the tubing has been eaten away. It is noted that this depth corresponds with a geometry change in the well where there are the two sharp angled turns or "dog legs" in the well. The pitting had increased significantly in the year of CO_2 injection. It was, therefore, inferred this could be the result of CO_2 corrosion or erosion due to hard cables in thee well or a summation of both corrosion and erosion mechanisms.

Questions and comments were directed at the cause of the pitting. The severity of the dog legs was postulated as one cause, the other that the pitting was the result of chloride induced attack; the chloride present in the production water might have stuck on the tubing and continued to corrode it even after production had stopped. Wet CO_2 corrosion was ruled out, although this was the initial feeling of most participants, because the CO_2 was dried before injection. However, minor traces of water which are still present in the CO_2 can be osmotically attracted by the chlorides and enhance localized corrosion. Another train of thought was that the tubing used, 13 chrome, was fairly soft and that the wire line tools themselves might be the cause of erosion especially around the area of the dog legs. Others felt that the caliper used is a simple tool and results can be misinterpreted. A more accurate tool could be used – Frans replied that they were considering using a video tool. Another line of questioning related to the geological formations around the depth of the pitting, if these were soft chalks that might be the cause of misinterpretation

4.1.2 Field experiences

Darryl Kellingray of BP introduced the second technical session and discussed remediation practices for wells with SCP. He emphasized that SCP indicates that there is a failure in the pressure envelope of the well. SCP is measurable at the wellhead of the casing annulus and so can be monitored. The implications of SCP for CO_2 injection are:

- CO_2 could escape outside the tubing which could lead to a corrosive environment around the well casing,
- Connectivity in the formation could occur allow CO_2 migration to shallower formations,
- The cement in or around the well could be exposed to CO_2 and hence it could degrade.

SCP can be detected by pressure testing or case hole logging. Although the diagnosis is not easy and you always have to go into the well to find the problem. Potential remediation techniques include injecting polymers or cement/polymer combinations. Other options include expandable tubular patches and injection of high density fluids. The issue becomes whether such techniques would be acceptable to regulators.

Fred Sabins of CSI Technologies reviewed field experiences of repairing wells with SCP. A number of features can result in cement sheath failure that can lead to SCP. These include stresses in the well bore, which can occur during pressure tests of the casing and during operational interventions and can occur as a result of thermal cycling. Stresses in the well bore can lead to cement deformation. There are a number of materials that can be used to remediate SCP including micro fine cements and low solid density sealants (polymers, gels and resins). Materials need to be injected or squeezed into the wells. A research project using a polymer has been reported[7] to significantly reduce SCP, although several treatments were needed. Gels can be used to remediate cement bond failure, tubing and casing leaks etc. There is a reported case of a gel repairing a casing leak which had not been successfully repaired with cement. Resins can also be used to seal casing leaks and SCP as well as for shutting off gas for abandonment. Again, there are case histories of their use where they have successfully sealed gas leaks. Expandable tubulars can also be used; in this case you run in a smaller ID pipe and expand against the existing well. Overall there are a number of products that can be used to remediate SCP, most work but their applicability is situation dependent. There are problems with these techniques; like placing the product, accessing the leaking annuli, the need in cases to cut holes in the liner etc., and there is also an expense associated with their use. Many of these options are good short term solutions but we are not sure about their long term sealing potential. Also we cannot be sure if such techniques they would be acceptable to regulators. It is likely that we will still need cements. There are several new cements available which are ultra fine and can be injected into smaller pores but we are not sure about their long term resistance. The ultimate option is a well work-over, these will be expensive but at least you have a degree of confidence that they will seal.

[7] SPE Paper 91399, Micro-annulus leaks repaired with pressure activated sealant.

Bull heading[8] can also be used to solve the problem but you may only be bottling up the gas and you might get a down hole leak somewhere.

> *Questions* referred to the use of expandable packers for leakage remediation, it was felt that this was not standard industry practice to apply them in this way and this may not be acceptable to promote them for this application. Also the limited life of polymers was questioned, 4 years at 400^0c was quoted, which may make them inappropriate for this remediation purposes

Yvonnick Vrignard of Schlumberger discussed the tools that his company had developed for logging well integrity. These tools can be used for isolation assessments or assessing the integrity of the piping. Tools for isolation assessments include sonic logging, pulse echoe techniques and annulus scanning. Acoustics are the most commonly measurement used. Piping assessments can use mechanical evaluations such as calipers, ultrasonics and electromagnetic techniques. All techniques are employable down hole. All the techniques have strengths and weaknesses but can be used in combination to determine well integrity.

Joe Anders of BP summarized their experience on well performance. BP has 2100 wells in the North Sea but 21,000 wells on the North Slope of Alaska. Based on their experience metal corrosion is more of a problem than cement. If you get a good cement completion then the well normally works well. On the North Slope, they have some pretty severe conditions with both high CO_2 and H_2S contents and large temperature variations. BP's approach to well integrity is that it is not just a drilling issue and they have a lot of staff employed on well integrity operations. In part this is brought about by ecological sensitivity in the Artic region. These staff are all certified and there are set procures and documentation on well bore performance. BP has experienced SCP on wells on North Slope and as many as 500 wells could be affected, about 120 of these wells are still operating but over 300 are no longer suitable for operation. Common failure occurrences on the North Slope are erosion, well subsidence[9], leaking elastomers and external corrosion. Joe summarized by setting out a number of points that he thought were relevant to long term well integrity, which were:

- A good cement completion is essential,
- Elastomer problems and casing corrosion are problems that occur after well completion,
- Tubing needs to be replaced at 5-20 years intervals and after 3 replacements you should plug and abandon the well.

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[8] Bull heading is an intervention technique where you forcibly pump fluids into a formation, usually formation fluids that have entered the well bore during a well control event. Though bullheading is intrinsically risky, it is performed if the formation fluids are suspected to contain hydrogen sulphide gas to prevent the toxic gas from reaching the surface. Bullheading is also performed if normal circulation cannot occur, such as after a borehole collapse. The primary risk in bullheading is that the drilling crew has no control over where the fluid goes and the fluid being pumped down hole usually enters the weakest formation. In addition, if only shallow casing is cemented in the well, the bullheading operation can cause well bore fluids to broach around the casing shoe and reach the surface. This broaching to the surface has the effect of fluidizing and destabilizing the soil (or the sub sea floor), and can lead to the formation of a crater and loss of equipment and life.

[9] Well subsidence is a particular feature of operations in Artic regions and is not typically found elsewhere.

For long term integrity he felt it was essential to know how old wells have been plugged and abandoned. To abandon a new well he would recommend pulling the tubing and casing, then cement all the way to the surface, but that will need a lot of cement. Of course the issue of abandoned wells is a big one, one question that needs to be faced is do you go back and reseal all old abandoned wells to ensure their integrity?

4.1.3 Laboratory experiments

Four presentations were given on laboratory experiments on Portland cement samples. George Scherer of Princeton University. George considered the greatest leakage risk is acid flow between the well casing and the cement rather than through the cement itself. Any reservoir model that can be used to predict leakage must to be able to predict the composition of brine in an aquifer that will come into contact with the cement in the well. Then we need to consider how the cement responds to the acidic brine, which is the focus of his laboratory work. This will enable you to model the brine in the annulus and determine how quickly the leak increases. Cement samples exposed to brine solutions in flow-through laboratory experiments showed that different layers were formed. An outer orange brown layer in which the calcium in the cement sample was heavily depleted a narrow white transition layer where calcium depletion was occurring and an un-reacted central grey layer. On removal the outer layer was found to have little or no mechanical integrity. Sensitivity studies indicated the calcium depletion was strongly accelerated by lower ph and higher temperatures[10]. It was considered that under typical conditions for a sandstone formation at 1km depth the rate of attack on cement would be 2-3 mm per month, assuming fresh acid was flowing over the cement. Batch experiments indicate that the depth of attack is diffusion controlled. Even under diffusion control the attack is evident in cement samples within weeks under typical conditions for a sandstone formation. The attack however is much less rapid in limestone formations. The rate of attack also slows as the layers develop, which could infer that a protective calcite layer is developing. Efforts to model the batch experiment data will now commence.

Marcus Wigand from LANL outlined the results of several experimental laboratory studies performed on well bore cement. These experiments were designed, in part, to understand the implications of observations of carbonation in SACROC[11] cement samples obtained from a well with 30 years of CO_2-exposure. Batch experiments and flow through experiment were performed on dried and water-saturated, intact and fractured cement cores using supercritical carbon dioxide ($SCCO_2$) at in-situ reservoir conditions. During these experiments the diffusion rate of $SCCO_2$ into the cement and the reactivity of the different cement phases were determined. Additionally geophysical and mechanical properties of the well bore cement before and after exposure to $SCCO_2$ were measured. The results indicated that the porosity decreased and compressive strength and density increased due to the reaction with $SCCO_2$. The

[10] The range of conditions tested were,: pH 2.4 to 3.7 and temperature 20^0c to 50^0c

[11]The SACROC unit was the first miscible CO_2 flood in the Permian Basin. The SACROC Unit, which was developed by Chevron, covers 50,000 acres and was formed to optimize secondary and tertiary recovery of oil in the Canyon Reef, a Pennsylvanian age reservoir. The reef has an average porosity of 4% and mean permeability of 19 millidarcies. It initially had 3 billion barrels of oil in place and has recovered 1.4 billion barrels to date.

reaction of the hydrated cement phases (portlandite and calcium silicate hydrates) with $SCCO_2$ resulted in the formation of calcite ($CaCO_3$), aragonite[12], vaterite[13], and dolomite ($CaMg(CO_3)_2$). The $SCCO_2$ migrated into the Portland-based cement several millimeters. The decrease in porosity was a result of calcium carbonate replacing portlandite. Precipitation of amorphous SiO_2 formed a low-permeability barrier impeding further movement of $SCCO_2$ into the cement. Flow-through experiments on fractured cement core resulted in partial healing in some regions and an opening of the fracture due to calcite precipitation in others. All results indicated the well bore cement kept its integrity and showed no signs of dissolution. The goal of future experiments will be the study of migration behavior of $SCCO_2$ along the cap rock/cement and casing/cement interfaces.

> *Questions* concerned the impacts of variables on the experiments. When asked if the water saturation has an impact on the reactions of cement phases with the $SCCO_2$ - the answer was yes. Also whether the Hassler-type core holder caused compaction of the sample and self healing to occur which may explain the differences observed in these experiments and those at Princeton? – the answer was yes with the comment that the idea behind using a Hassler core holder was to simulate in-situ reservoir conditions whereas the experiments performed at the University of Princeton were performed at atmospheric pressure. The source of the magnesium for the dolomite formed was questioned; Marcus Wigand pointed out that the experiments were performed under in-situ reservoir conditions and the source for the magnesium could be the brine which had a composition comparable with the formation water of oil reservoirs of the Permian Basin[13].

Gaëtan Rimmelé presented the work that Schlumberger had been doing on the alteration of Portland cements by CO_2. The work was aimed at obtaining a better understanding of the alteration processes for Portland cement that occur in a CO_2 environment and under down hole conditions. High pressure tests on Portland cements indicated that carbonization was occurring again forming calcite, vaterite and, aragonite. Porosimitry experiments indicated that a rapid decrease in porosity occurred in the cement samples after 8 hours of exposure. The decrease peaked around 500 hours of exposure and then increased again. The porosity decrease occurred around the rim of the sample initially and then gradually moved inwards as exposure time increased. Effectively this was tracking the carbonation front in the sample. The results were interpreted as showing that dissolution of $Ca(OH)_2$ occurred quite rapidly throughout the whole sample. This was followed by a sealing effect as carbonation occurred which was followed by precipitation, which caused the increase in porosity. The carbonization reaction therefore does not continuously plug the

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[12] Aragonite and vaterite are both polymorph $CaCO_3$, i.e. they are both different mineral forms of calcium carbonate.

[13] [13]The Permian Basin is a sedimentary basin largely contained in the western part of the U.S. state of Texas. It reaches from just south of Lubbock, Texas, to just south of Midland & Odessa, extending westward into the southeastern part of the adjacent state of New Mexico. It is so named because it has one of the world's thickest deposits of rocks from the Permian geologic period. The greater Permian Basin comprises several component basins: of these, Midland Basin is the largest, Delaware Basin is the second largest, and Marfa Basin is the smallest. The Permian Basin extends beneath an area approximately 250 miles wide and 300 miles long.

cement. It was suggested that this work identified the need for the development of a CO_2 resistant cement.

> *Questions* again generally concerned the validity of the experimental process. For example, there was some concern about how the carbonic acid got to the centre of the cores if the permeability was only a few mDarcy, the answer was that there was no flowing water but the samples were immersed in water before testing.

Barbara Kutchko, outlined the results of high pressure laboratory tests on cement that NETL were undertaking. She emphasized the need for such work by stating that there were 1.5 million deep holes in Texas alone, of these 360,000 wells were active and registered with the Texas railroad commission. Barbara stressed the need to understand how cement degrades in the presence of CO_2 charged brines. Tests were undertaken on a Class H[14] cement at temperatures ranging from ambient to 50^0c and from atmospheric pressure to 4400 psi (303 bar). The cement was prepared in accordance with API specifications and hydrated for 28 days by immersion in 1% NaCl solution. When exposed to an aqueous phase saturated with water the typical soft outer orange layer was observed on the cement sample which was calcium depleted and with a lower mechanical integrity. Further work will now be undertaken to look at the effect of binders (such as bentonite and fly ash) on cement degradation.

Veronique Bartlet-Gouédard of Schlumberger presented on their work on the development of a CO_2 resistant cement. For long term zonal isolation Portland cement was not favoured because it was not stable in CO_2 environments. This issue she felt was not adequately addressed by current industry specifications. Schlumberger were developing a standard laboratory procedure to assess CO_2 resistant cements and were looking at the long term modeling of the cement –sheath integrity. Their work on CO_2 resistant cement was focused on: finding a durable material that would reduce the amount of portlandite in the cement. In addition, it was felt to be important to have a low water content in the cement system and the cement slurry needed to have a large density range. Their initial tests on a CO_2 resistant cement that they had designed were very positive. The CO_2 resistant cement tested demonstrated little carbonation and was stable under laboratory conditions for 3 months. Note: comparable tests on Portland cement showed that extensive degradation had occurred in similar time scales.

> *Questions* referred to the availability of this new cement, which was quoted as October 2006, and to the properties of the cement. In response, the audience was told that permeability resistance in cement was not sufficient on its own, that chemical resistance was needed. Also the addition of silica (up to 30-40% by wt.,)

[14] Class H cement is cement marketed for use in wells in Texas. It has high sulfate-resistance, is used from surface to depths down to 8,000 feet (3600m) when special properties are not required. It can also be used with accelerators and retardants to cover a wide range of oil well depths and temperatures. The cement is produced to API Standard 10A - Specification for Cements & Materials for Well Cementing 23rd Edition 2002. This standard specifies requirements and gives recommendations for eight classes of well cements, including their chemical and physical requirements and procedures for physical testing. This standard is applicable to well cement Classes A, B, C, D, E and F, which are the products obtained by grinding Portland cement clinker and, if needed, calcium sulfate as an interground additive. The standard is also applicable to well cement Classes G and H, which are the products obtained by grinding Portland cement clinker with no additives other than calcium sulfate or water.

was not sufficient on its own because this still left a lot of free lime which can react with the CO_2.

A general comment was made after the laboratory presentations, which was: that all of the presentations indicated that in the field all the wells in Texas would have been destroyed in a matter of days due to exposure to CO_2. However, in practice there is still a lot of cement in the wells after 30 years of operation. This disparity between laboratory experiments and field conditions needed to be addressed.

4.1.4 Modeling results

Mike Celia of Princeton University introduced the session by briefly summarizing what had been presented earlier. The laboratory experiments had shown various degrees of degradation of Portland cement when exposed to CO_2 and a lot of differences in behaviour. How do we make sense of this and compare these results to the field cases? This is the role of modeling to allow us to compare the different approaches.

Bill Carey of LANL, then outlined the work they were doing on reactive transport modeling of cement –brine - CO_2 systems. The work was aiming to simulate the cement carbonation observed in a sample of cement removed from the SACROC field that had been exposed to CO_2 for thirty years. Where CO_2 saturated brine had diffused along a porous zone along the cement-shale interface. In addition, the work was also modeling the laboratory studies by Princeton, presented earlier by George Schrer. Initial results indicate that diffusion based models can capture the key elements of cement degradation. The results indicate that the behaviour of the cement–brine-CO_2 system is a function of tortuosity[15] and reaction rate. However, to allow the atmospheric pressure laboratory experiments to be modeled significantly higher reaction rates and tortuosity factors are needed to explain the depth of penetration observed compared to the field sample. Next steps will be to try and translate cement degradation into effective leak rates.

Bruno Huet from Princeton University presented the work they were undertaking to develop a geochemical code to enable them to model cement reactivity in CO_2/brine mixtures. Bruno stressed the need for a coupled geochemical transport model to allow them to model multi phase transport along potential high permeability pathways in well bores and the model cement degradation through contact with CO_2 rich brine solutions. Currently the work was looking to incorporate data such as homogeneous chemistry and temperature effects into the code and reaction kinetics. Future work will aim to incorporate multiphase transport flow, using PU flash and then undertake 2D simulations to model CO_2 flow up the well bores.

Kris Ravi of Halliburton discussed the physical effects that will need to be considered when modeling well bores. SCP was induced due to a number of operational shortcomings. In particular, careful attention to hole cleaning and cement slurry placement during well installation should significantly reduce SCP. Well operations such as pressure testing, hydraulic stimulation, production and injection and down

[15] Tortuosity is the single most important characteristic of flow through porous media that determines several flow and transport phenomena. For unsaturated media, tortuosity factor (ta) is defined as the ratio of the specific air-water interfacial area of real and the corresponding idealized porous medium.

hole conditions particularly if chemicals are present as well as pressure and temperature in the well can also affect SCP. Several post drilling operations can affect the integrity of the well. These can include:

- Cement slurry hydration leading to hydration volume reductions
- Completions which can cause pressure decreases inside the well casing
- Pressure testing which can cause pressure increases inside the casing
- Hydraulic fracturing – again can lead top pressure increases,
- Production which can lead to pressure/temperature increases inside the tubing

Laboratory experiments performed by Halliburton indicate that in cases such operations can lead to damaged cement sheaths, or debonding between the casing and the cement sheath or between the rock and the cement.

Mike Celia of Princeton provided the final lecture on large scale modeling of leakage along wells. Princeton University has developed a semi-analytical model. The components of the model consist of: an injection plume evolution code, a leakage dynamics code a post injection redistribution code and a code to establish leakage via wells. The model has been tested using a field situation in the Wabamun lake area of the Alberta basin near Edmonton. The area has a large number of CO_2 sources and would be an ideal region for CO_2 storage. The area has been extensively drilled. Initial simulations are based on assumed permeability data, part of the discussion was aimed at eliciting from the experts in the audience the key data that should be included in the model and trying to find source data that could be used in the model. Modeling art this scale presents a challenge, but a challenge that needs to be addressed especially in areas of high drilling density like the Alberta basin where they are many wells and many geological layers all of which need to be included in the model.. Along side the modeling programme Mike advocated the need for a comprehensive experimental programme of to determine the important properties of existing wells that need to be modeled so that leakage can be predicted.

4.2 Breakout Groups

Three breakout groups were planned to address the following issues:

Group 1 – Historical well bore integrity issues

This group was led by Stefan Bachu (AUEB) and Mike Celia (Princeton). The remit of the group was to consider historical well integrity issues and how well integrity issues are identified. The group aimed to synthesise what we had learnt and identify gaps or additional issues that need to be addressed

The group focused its discussions on all existing wells; they also felt it was important not to forget about integrity issues with wells that have noting to do with CO_2. The group felt that it needed to remember that old wells were drilled shallower than current wells, and we have a pretty good knowledge of depth of drilling versus time. This information puts constraints on the age of wells we need to worry about –the location/existence of many older wells may not be known. The group also felt it needed to consider the well integrity situation globally, but recognizing geographical (historical) differences for instance in North America and the North Sea and other parts of the world.
The group noted the following issues regarding the integrity of historical wells:

1. The question was raised if there is a 'history' of well construction technology and practices, in easily accessible form? Such information could give a snapshot/synopsis, including statistics that might be useful when designing well characterisation/monitoring/remediation plans?

2. It was acknowledged that well analysis will have to be a central component of site characterization and selection. Inherent issues here are:
   - How many off-set wells will be reached by the CO_2 plume?
   - Also there is an economic issue – will all/some wells have to be remediated a priori?

3. Can we assign broad classifications to wells? If we can then we can group 'like' wells and therefore have a simpler categorization for historical wells? Issues to be considered include:
   - What set of parameters should we assign to each of the well categories?
   - We need to link the well categories with (statistics of) properties/characteristics of the wells (for example, permeability, etc.) But we do not know what statistical properties/characteristics exist and which are significant?

4. How to obtain representative information will be a big issue. There is the usual problem of how to access records that exist in the oil industry. Some potential sources of information include: surface casing vent flows (inside casing), gas migration (outside casing) and SCP. It was noted that it is not obvious how best to use this information, or if there are other measurements that could be done to help us understand the behaviour and properties of old wells. Regulators in various countries track this kind of information and this information needs to be accessed. Well blowouts data might be another valuable source of information – however it was noted that most land-based well blowouts are reported but not published.

5. It was felt that it could be valuable to examine catastrophic releases of CO_2 and other fluids (natural gas) to understand the limits of possible risk and damage.

Other points noted included

- The importance of modern well testing tools to identify problems in wells needs to be considered.
- It was pointed out that in the future CO_2 wells will be purpose designed for that activity, whereas existing wells will not.
- We must not forget about water wells, which can be important in many regions (at least secondarily) as leakage conduits in shallow zones, but also can be important as possible monitoring opportunities.
- Integrity includes seals more generally, not just the wells, but wells are likely to be much higher risk than seals.

Group 2 – Well bore materials and mechanisms of attack.

This group was led by Bill Carey (LANL) and Darryl Kellingray (BP). The remit of the group was to consider what we know about well bore materials and how they are attacked by CO_2. The group aimed to synthesise what we had learnt and identify gaps or additional issues that need to be addressed

As far as well bore materials were concerned, we know that Portland cement reacts rapidly with CO_2 and that most additives such as fly ash and silica flour don't help with mechanical integrity. For monitoring cement integrity, cement sheath evaluation/surveys important and pressure and SCP history data would also be helpful in identifying problems.

As far as the casing is concerned, steel and elastomers are as important to consider as the cement, since the steel will go first. One question raised, however, is that if the well is abandoned and casing is surrounded by cement, perhaps casing issues may not a problem. We know that erosion control measures can affect casing quality and pipe connections are weak points for attack

Clearly abandonment procedures are very important to the long term integrity of a well. Well intervals that aren't cemented may actually collapse with time, mud logs for the evaluation of formation damage, but we do not know if damage around well bore matters. How much of the abandoned well is cemented will be a big issue as will finding the old abandoned wells on fields.

Another important issue that needs to be known is how previous well operations could have affected the wells integrity?

As far as mechanisms of attack are concerned the location of the attack by CO_2 will be a factor. Attack on the cement from the bottom of the well should pose less of a problem if we have 10 m of cement will it really degrade all the way through in a timescale that we need to worry about? It is likely that micro annuli in the cement may always be present which is important because this will contribute to the scale of the attack.

Questions that we need to address are:

- What is the most aggressive CO_2-brine attacking fluid?
- How wet is the CO_2? Because we can't displace the oil we probably can't displace all of the water.
- Does the cement develop a low permeable deposition zone that "protects" the cement?
- Can reservoir choice help pacify the CO_2?
- Are other components of CO_2 stream e.g. H_2S or hydrocarbons, may be important
- The nature of reservoir may be important, wells in traps concentrate the CO_2 and pressurize formation may be more at risk than wells in open migrating systems
- Can we depend on cement as the ultimate barrier, as the pipe doesn't offer protection?
- Do fractures heal or open with CO_2 flow?

Information that would be helpful would be a survey of actual leaks-to-surface of CO_2 along with costs of work-overs and SCP data records

In summary the group felt that overall a poor cement job is probably the most fundamental issue determining well integrity. If we get a poor cement job maybe we need to focus on other materials like the steel first. Also, we need an accelerated test methodology to be able to predict degradation in wells.

Group 3 – Well bore integrity experiment

Group 3 were led by Charles Christopher(BP) and Rick Chaltaurnyk (University of Calgary). The group were given the remit of designing an experimental programme to assess well bore integrity.

The aim was therefore was to select a well and determine if CO_2 has attacked it. The group approached this activity in a step wise manner. The steps considered were:

- How do we choose a well?
- How do we characterise it?
- What do we do to the well?
- What do we do with samples?
- What modelling and simulation is needed?

As far as well selection was concerned we need to decide whether you select a producer or an injector? For CCS operations we will only use injectors, but old producers converted to injectors will likely be main source of problems

Wells selected should have the following features:

- Access is required,
- It should be scheduled for abandonment, but should still be controllable,
- Need to consider reason for abandonment, i.e. it should have failed a mechanical integrity test or watered out,
- Good history - historical data must be available, particularly on issues such as type of cement used, production history and mud cleaning. Petrophysical analyses would be beneficial,
- If the well had SCP,
- Whether other well types are also available with different characteristics,
- A minimum to 4 to 4.5" diameter to get widest range of tools available.

Well characterisation - non destructive – tests could include the following

- Logging suite logs (tubing then casing)
    - Mechanical, sonic and electromechanical
- Fluid analysis
- In well micro-seismic (active source)
- Casing analysis
- Video camera
- Gas analysis

Well Intervention tests could include

- Sidewall cores – multiples
    - Next to aquitards, aquifer
- Kick off cores – multiples
- Tracers – to identify flow paths in cement
- Pulse tests (cross well)

- Collect fluid samples from various formations
- Hydrojeting out a vertical large slot of tubing and casing
- Special sampling conditions need to be considered to preserve samples
- Core preservation

Sample analysis would include:

- Petrographic and geochemical (water, core etc.,) & mechanical/thermomechanical analyses
- Micro mechanical strength
- CAT scans on cores
- Cement analysis
- Metallurgical analysis
- Elastomers – packers etc.,
- CO_2 reaction kinetics – cement , rock

The next step would be to find a suitable well that has been exposed to CO_2. Options considered included: Penn west/Weyburn in Canada, Tea pot dome and Sheep Mountain in the USA and a Petrobras well in, Brazil

4.3 Large scale projects

At the end of the day Scott Imbus from Chevron presented the outline of a field study that was being prepared by CCP2. An integrated CO_2 well bore integrity field study is proposed to assess well condition, and document and model the degradation processes and rates in the well. The data will then be used to simulate future well

The study would comprise the core of a more "comprehensive well integrity program" and the basis for new, cost-effective well designs and remediation and intervention techniques.

Major tasks include:

- Well selection & evaluation
- Well sampling, analyses & experiments
- Model construction with history match
- Forward simulation
- Engineering solutions

Scott invited the participants at the workshop to provide ideas and recommendations for the study.

This study was in part stimulated by the results from the previous well bore integrity meeting held in Houston in 2005.

5. Summary

Charles Christopher of BP summed what had been achieved at the meeting. The task before us concerns risk management and risk reduction. We need to convince the regulators that CCS is safe. To do that we need to assess areas of risk and we know that well bores pose a major risk issue.

This group can play a role by bringing together statistical and mechanistic data that the modelers can use to tell what the long term risks are. But we also need more samples and in particular cement samples from wells that have been exposed to CO_2 and from some that have not. We especially need more samples because we see a disconnect between the results pf laboratory experiments which indicate very rapid cement degradation and field experiments where degredation is much less marked. We need to be able to resolve these differences.

Another option is to ask the operators to use cement that is resistant to CO_2. However they will be reluctant to use a new material because they have years of experience with Portland cements and we need to prove to them that there is an issue that needs to be resolved.

Regarding the steel degradation observed in Texas can corrosion inhibitors be used to protect the steel, but is this an issue if we get a good cement job?

6. Key Conclusions

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

1. There is clearly a problem with well bore integrity in existing oil and gas production wells, worldwide. The main cause of this problem appears to be poor cementing practices. This problem has been recognized by the industry and new standards are being introduced to reduce this problem in the future. However, this leaves a legacy of old wells in oil and gas fields which may need extensive reworking be fore they can be considered suitable for use in CCS operations and to ensure their long term integrity.

2. It is established that cement can be degraded by CO_2, however the degree of degradation observed in laboratory tests and from the limited field samples available show large differences. Laboratory experiments infer that the cement in the wells will be degraded in a matter of days, whereas field data shows some degradation has occurred but nothing like as severe. More field based samples are required and better correlation between reservoir conditions and the laboratory experiments are needed.

3. Whilst cement is one issue, potential corrosion problems with the steel casing and elastomer failures should not be overlooked as possible causes of leakage in wells. Improved well completion practices may help by reducing CO_2-brine access to the metal casing, by improving cement integrity within the well. However, for the long term i.e. after abandonment it might be best to remove the tubing and fully seal with cement.

4. New CO_2 resistant cements are now coming onto the market, but we need to establish cost issues and the suitability of these cements to provide good casing and rock seals in real applications.

Issues to be considered in the future include:

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

Appendix 1. Delegates List

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Appendix 2

Day 1	
Session 1. Introduction	
Welcome/ Safety/ Context	Charles Christopher, BP, John Gale IEA GHG, Mike Celia Princeton
Session 2. Studies of Well Bore Integrity **Chair: Rick Chalaturnyk, University of Alberta**	
K12-B CO_2 Injection Site	TNO – Frank Mulders
North Estes Field in Texas	Chevron – Mike Powers
Weyburn Well Study	University of Alberta - Rick Chalaturnyk
MMS Studies on Wells	BP – Walter Crow
API Activity including Sustained Casing Pressure and Field and Regional Area Studies.	Halliburton – Ron Sweatman
Session 3. Field Experiences **Chair: Daryl Kellingray, BP**	
Introduction/Remediation of Wells with Sustained Casing Pressure	Daryl Kellingray, BP
Advanced Wireline Logging Techniques for Well Integrity Assessment	Schlumberger – Yvonnick Vrignaud
Repairing Wells with Sustained Casing Pressure	CSI – Fred Sabins
Dealing with Wells with Poor Annular Integrity	BP – Jo Anders *Teleconference from Alaska*
Session 4. Laboratory Studies of CO2 - Cement Reactions **Chair: Bill Carey, LANL**	
Corrosion of Cement in Simulated Limestone and Sandstone Formations.	Princeton – George Scherer
Core-flood and Batch Experiments on Carbonation of Casing-Cement-Shale Composites.	LANL – Marcus Wigand
Quantifying CO_2-related Alteration of Portland cement: experimental approach and microscopic methodology.	Schlumberger – Gaetan Rimmele

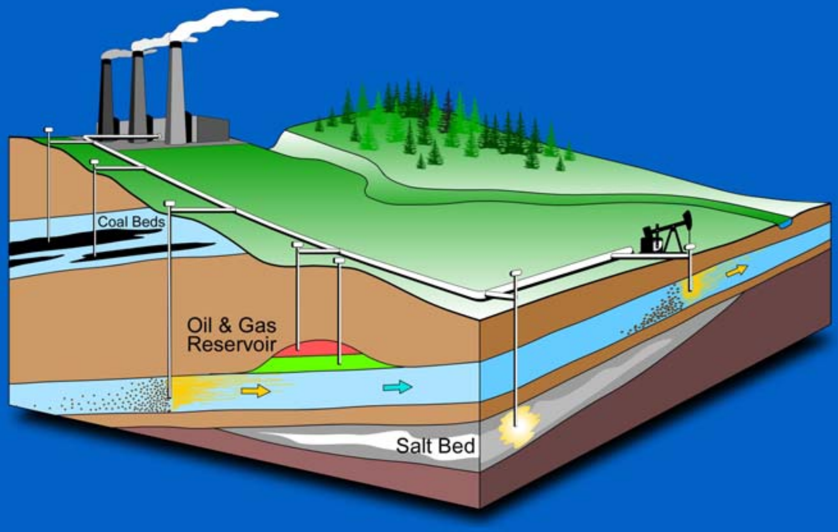
Day 2	
Degradation of Well Cement Under Geologic Sequestration Conditions.	NETL – Barbara Kutchko
Resistant Cement for CO_2 storage Process.	Schlumberger – Veronique Barlet - Gouedard
Session 5. Modelling Well Bore Integrity **Chair: Mike Celia, Princeton University**	
Reactive Transport Modelling of Cement-Brine-CO_2 systems: Application to SACROC	LANL – Bill Carey
Recent developments for a geochemical code to assess cement reactivity in CO_2/brine mixtures	Princeton – Jean Prevost
Effect of Well Operations and Downhole Conditions on Cement Sheath	Halliburton – Kris Ravi
A Large-scale Modelling Tool for Leakage Estimation and Risk Assessment	Princeton - Mike Celia
CO_2 Storage Well bore Integrity Field Study: A CCP2 Proposal	Chevron - Scott Imbus
Session 6. Breakout Sessions - Ensuring Well Bore Integrity in the Presence of CO2	
Introduction to Breakout Sessions	
Reports from Breakout Sessions and Discussion	
Session 7. Summary, Discussion and Close **Chair: Charles Christopher, BP**	
Concluding discussions, next steps and proposals for next meeting	
End of Meeting	

Wellbore Integrity Workshop: Introductory Remarks

Michael A. Celia
Princeton University

Outline

- Safety Moment
- Overview of Princeton University and CMI
- Comments on the Workshop



Safety Moment

- Exit out back of room, turn left, go up stairs and out doors.
- Fire Alarm: Very loud siren

Princeton University

- Small university in central New Jersey
  - Approximately 4,500 undergraduate students
  - Approximately 2,000 graduate students
- Founded in 1746
- School of Engineering and Applied Science is one of the Professional Schools at Princeton.
- Princeton Environmental Institute formed in 1992.
- Carbon Mitigation Initiative began in 2001.



Carbon Mitigation Initiative at Princeton

Carbon Capture

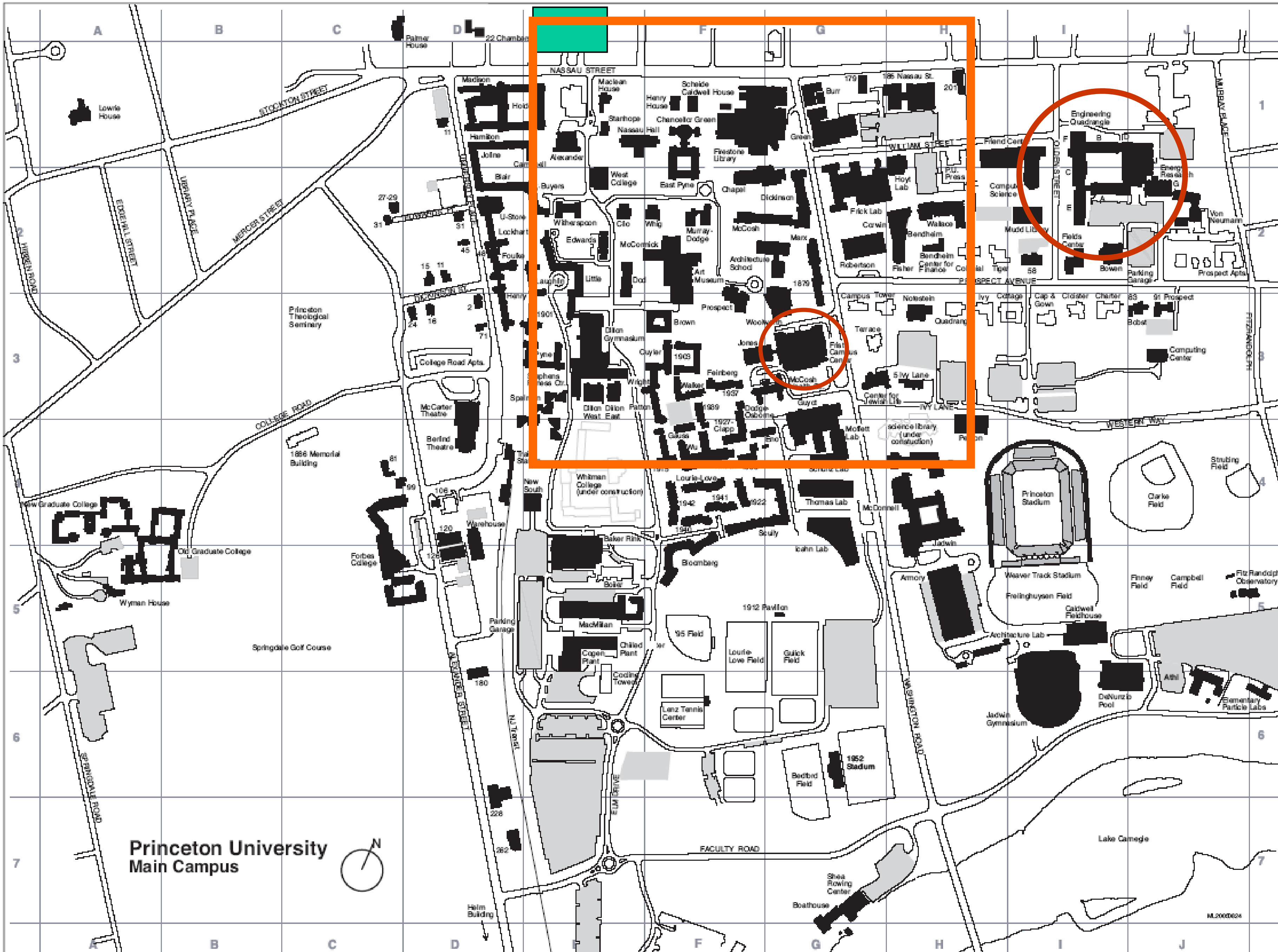
Carbon Storage

Carbon Mitigation Initiative
CMI
Carbon Mitigation Initiative
Princeton University

PEI
PRINCETON
ENVIRONMENTAL
INSTITUTE

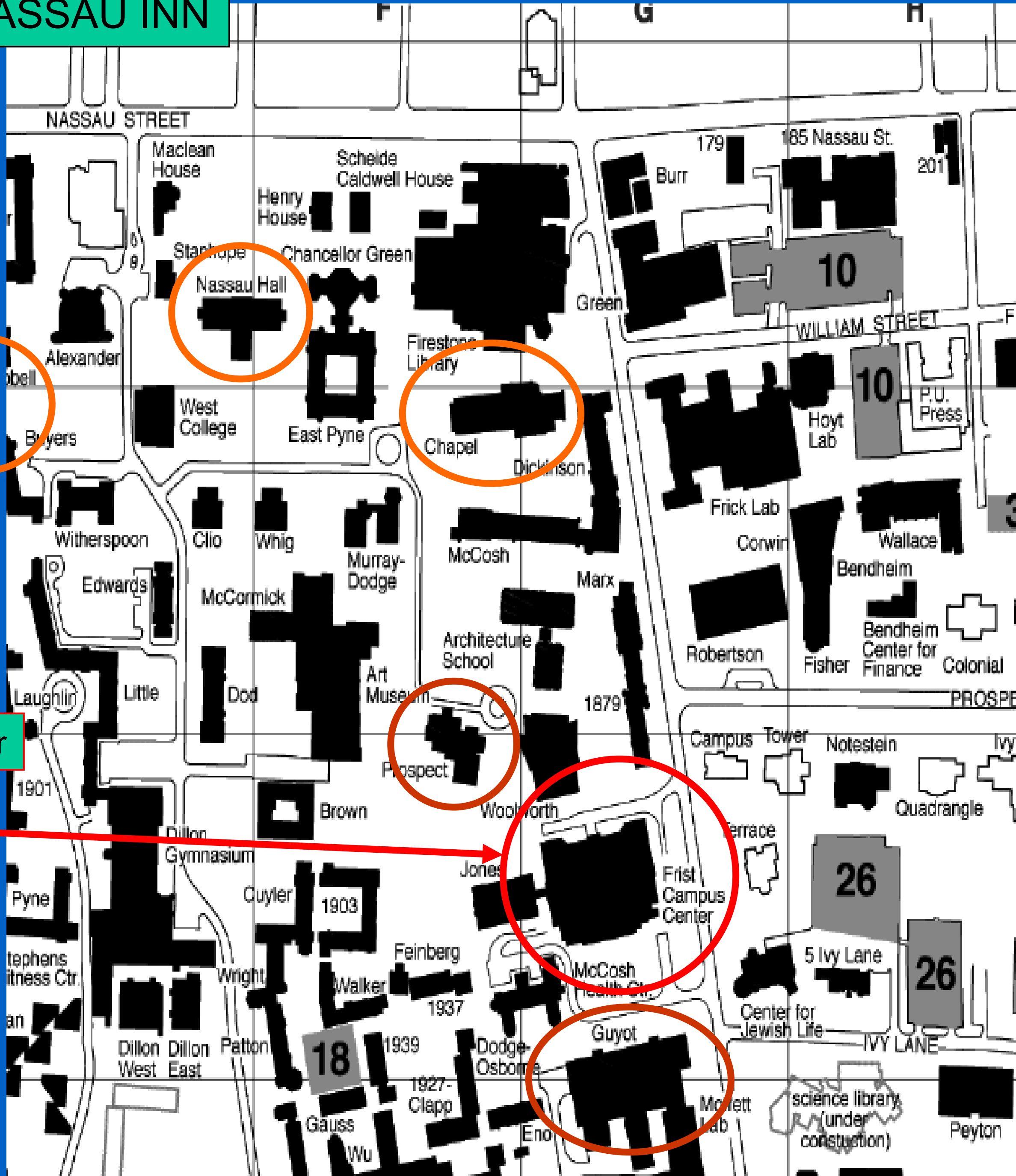
Carbon Science

Carbon Policy



Princeton University
Main Campus
NASSAU STREET
STOCKTON STREET
MERCER STREET
LIBRARY PLACE
EDGEHILL STREET
HIBBEN ROAD
COLLEGE ROAD
UNIVERSITY PLACE
ALEXANDER STREET
WILLIAM STREET
PROSPECT AVENUE
OLDEN STREET
MURRAY PLACE
FITZRANDOLPH
IVY LANE
WESTERN WAY
WASHINGTON ROAD
FACULTY ROAD
ELM DRIVE
SPRINGDALE ROAD
DICKINSON ST.
NJ Transit
Palmer House
22 Chambers
Lowrie House
Madison
Hamilton
Joline
Blair
Buyers
U-Store
Lockhart
Foulke
Henry
1901
Laughlin
Little
Witherspoon
Edwards
Alexander
West College
East Pyne
Chapel
Firestone Library
Nassau Hall
Stanhope
Maclean House
Henry House
Scheide Caldwell House
Chancellor Green
Clio
Whig
Murray-Dodge
McCosh
McCormick
Dod
Art Museum
Architecture School
Dickinson
Marx
1879
Prospect
Brown
Dillon Gymnasium
Cuyler
1903
Jones
Woolworth
Frist Campus Center
Feinberg
Walker
1937
Wright
Patton
1939
1927-Clapp
Dodge-Osborne
Guyot
Moffett Lab
Dillon West
Dillon East
Spelman
Stephens Fitness Ctr.
Pyne
Burr
179
185 Nassau St.
201
Green
Frick Lab
Hoyt Lab
P.U. Press
Corwin
Wallace
Bendheim
Robertson
Fisher
Bendheim Center for Finance
Colonial
Tiger
58
Friend Center
Computer Science
Mudd Library
Engineering Quadrangle
Energy Research
Von Neumann
Fields Center
Bowen
Parking Garage
Prospect Apts.
Campus Club
Tower
Notestein
Quadrangle
Ivy
Cottage
Cap & Gown
Cloister
Charter
83
91 Prospect
Bobst
Terrace
Computing Center
5 Ivy Lane
Center for Jewish Life
science library (under construction)
Peyton
Princeton Theological Seminary
College Road Apts.
McCarter Theatre
Berlind Theatre
1886 Memorial Building
New Graduate College
Old Graduate College
Wyman House
Forbes College
Springdale Golf Course
Whitman College (under construction)
New South
Warehouse
Baker Rink
Bloomberg
Louis-Love
1942
1941
1922
1915
1940
Scully
Schultz Lab
Thomas Lab
McDonnell
Icahn Lab
Jadwin
Armory
Princeton Stadium
Weaver Track Stadium
Frelinghuysen Field
Clarke Field
Strubing Field
Finney Field
Campbell Field
FitzRandolph Observatory
Caldwell Fieldhouse
Architecture Lab
Jadwin Gymnasium
DeNunzio Pool
Elementary Particle Labs
Lake Carnegie
Bolsar
MacMillan
Cogen Plant
Chilled Plant
Cooling Tower
Parking Garage
1912 Pavilion
'95 Field
Lourie-Love Field
Gulick Field
Lenz Tennis Center
Bedford Field
1952 Stadium
Shea Rowing Center
Boathouse
Helm Building
180
228
262
120
126
106
99
81
71
24
16
15
11
27-29
31
45
48
A B C D E F G H I J
1 2 3 4 5 6 7

NASSAU INN



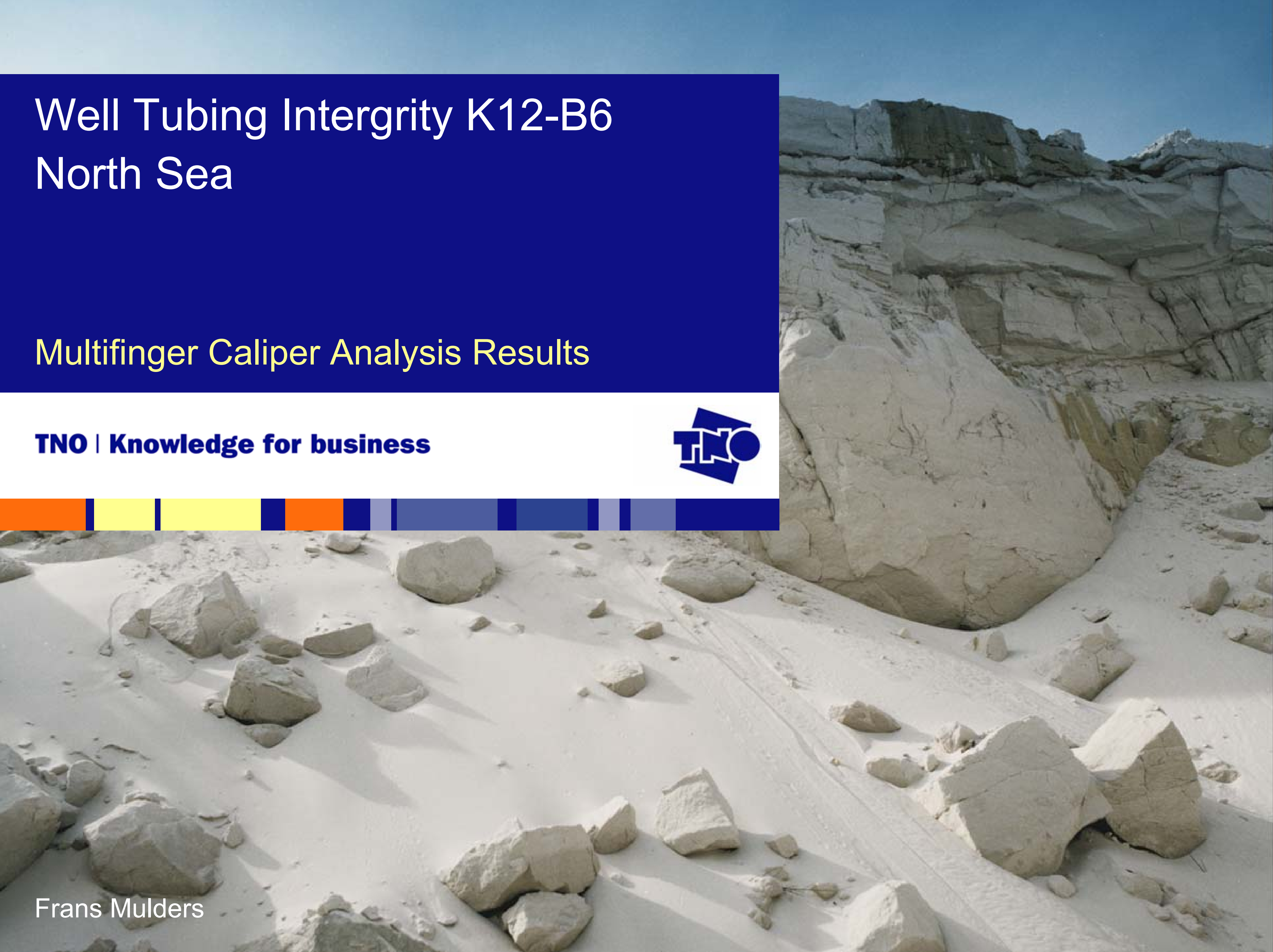
Frist Campus Center


THE PEI-PUP ENVIRONMENTAL PRIZE LECTURES FOR 2006
PRINCETON ENVIRONMENTAL INSTITUTE AND PRINCETON UNIVERSITY PRESS
present
DAVID TILMAN
Department of Ecology, Evolution, and Behavior
University of Minnesota
WEDNESDAY ■ MARCH 29
Stochastic Niche Theory, Neutrality, and the Controls of Invasion and Community Assembly
THURSDAY ■ MARCH 30
The Coexistence Paradox: Ecological and Evolutionary Mechanisms for Earth's Biodiversification
FRIDAY ■ MARCH 31
Biodiversity, Renewable Biofuels, and Ecosystem Services: A Path Toward Energy and Environmental Sustainability
ALL LECTURES ARE AT 8 P.M.
IN FRIEND CENTER 101
A reception will be held in the Friend Center after each lecture

Well Tubing Intergrity K12-B6
North Sea

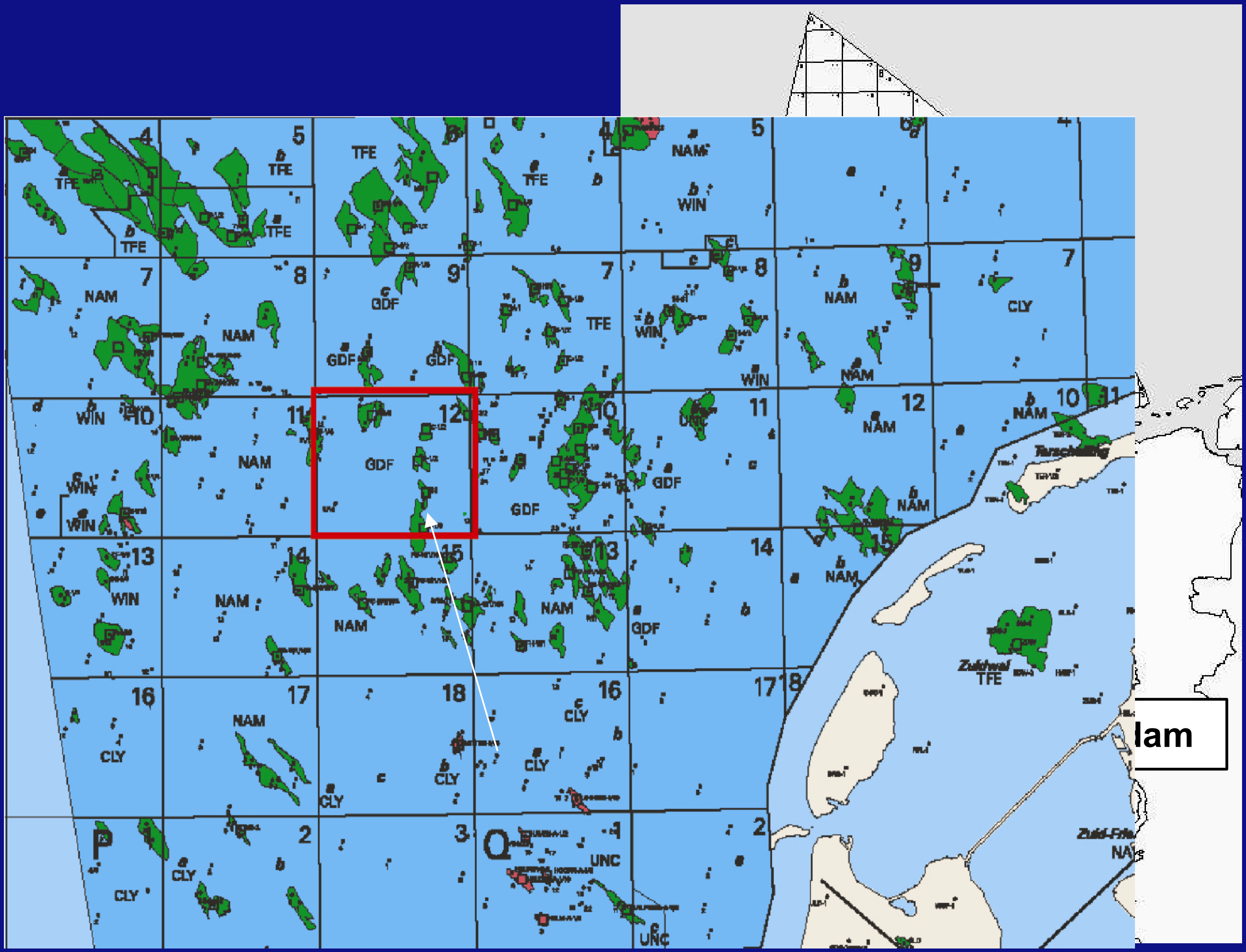
Multifinger Caliper Analysis Results

TNO | Knowledge for business



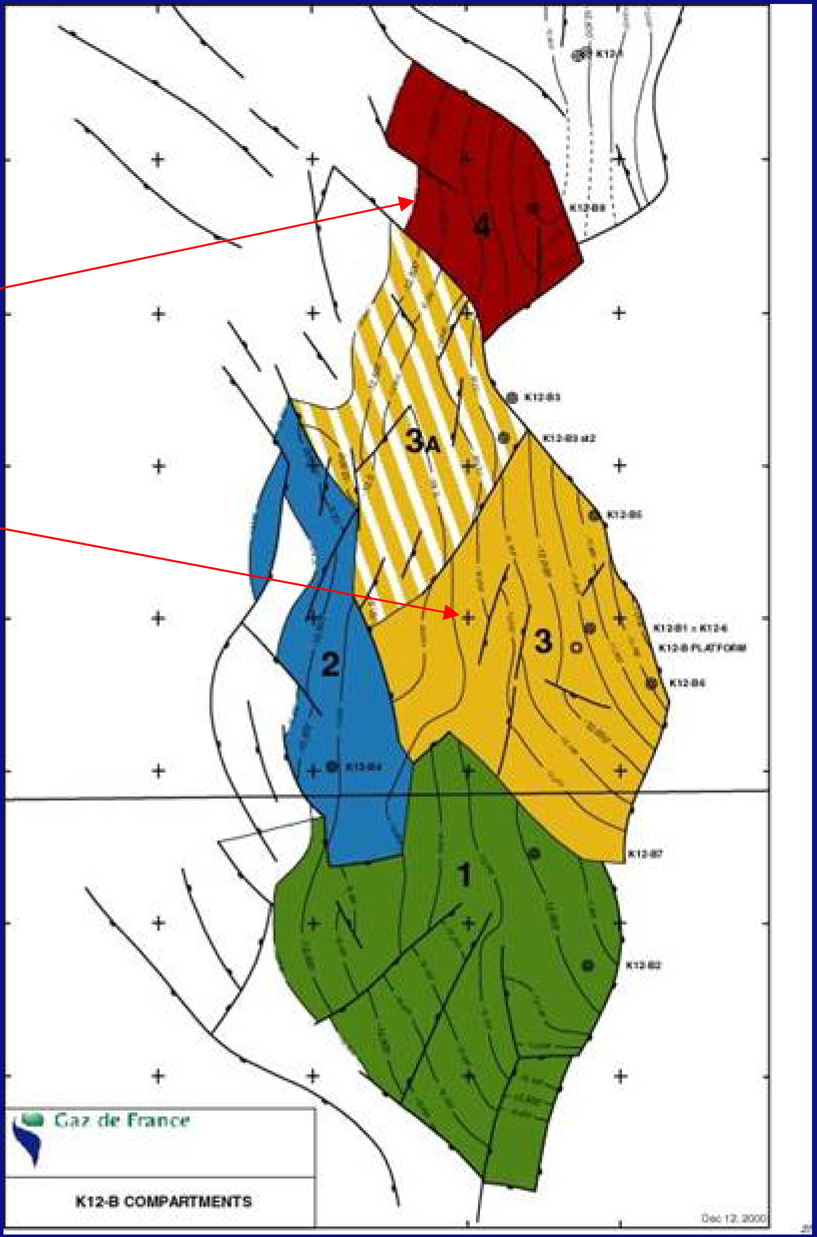
Frans Mulders

Location of K12-B



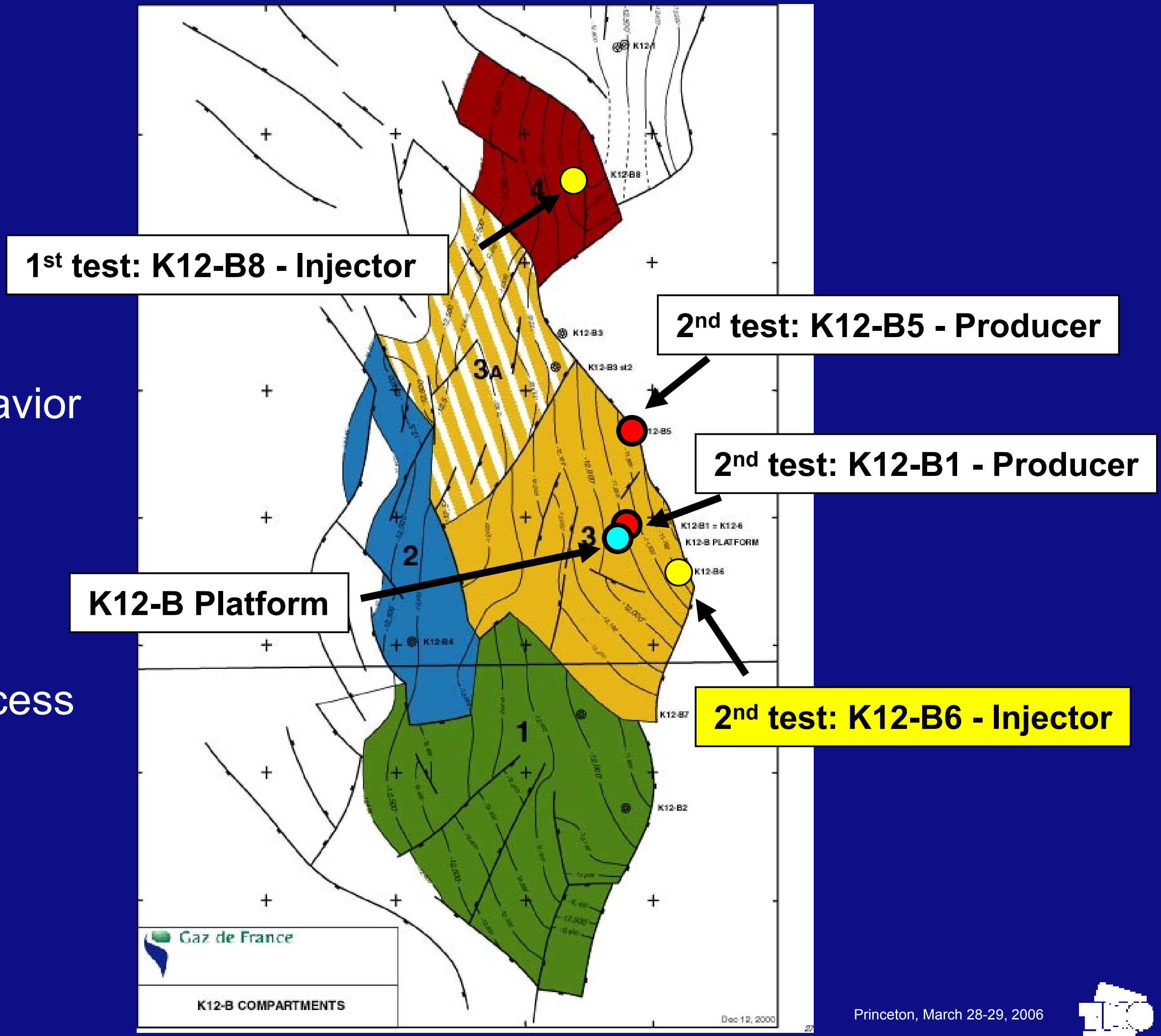
K12-B Compartments

- Single well compartment
- CO_2 injector and gas producers

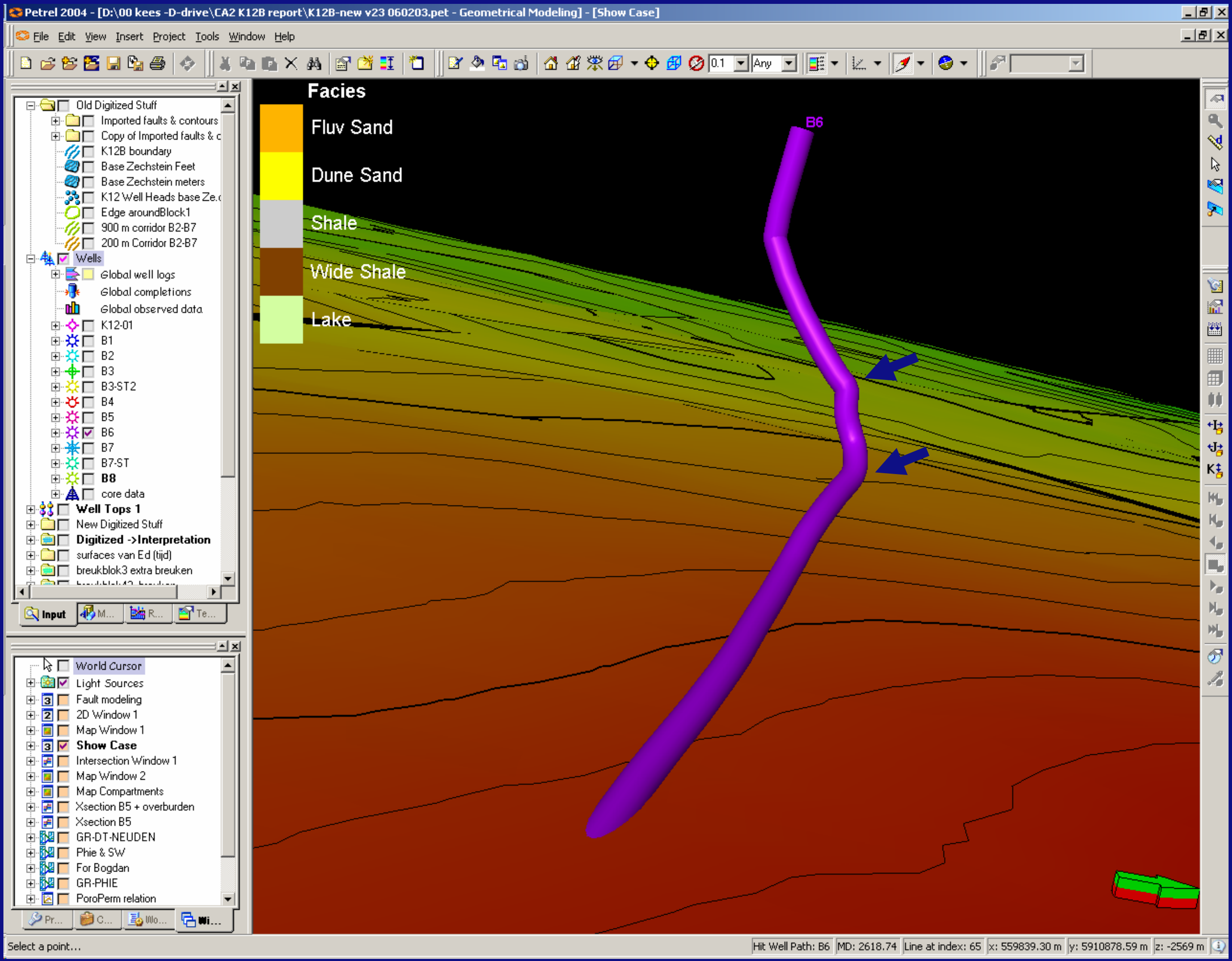


Field Geometry and Well Locations

- Test 1
  CO_2 wellbore behavior
  CO_2 injectivity
- Test 2
  Displacement process
  EGR possibilities
  Economics



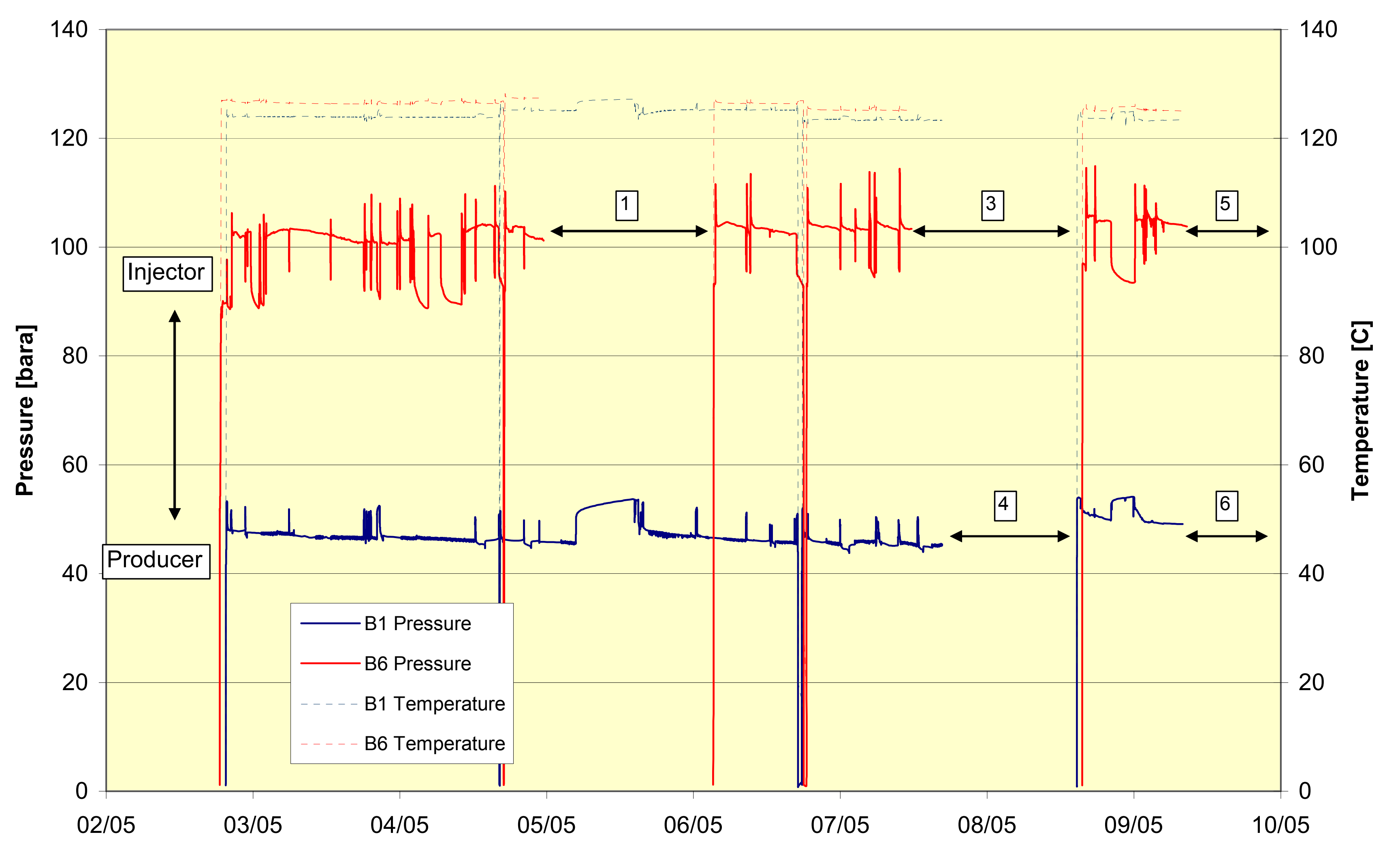
Well K12-B6 - Geometry



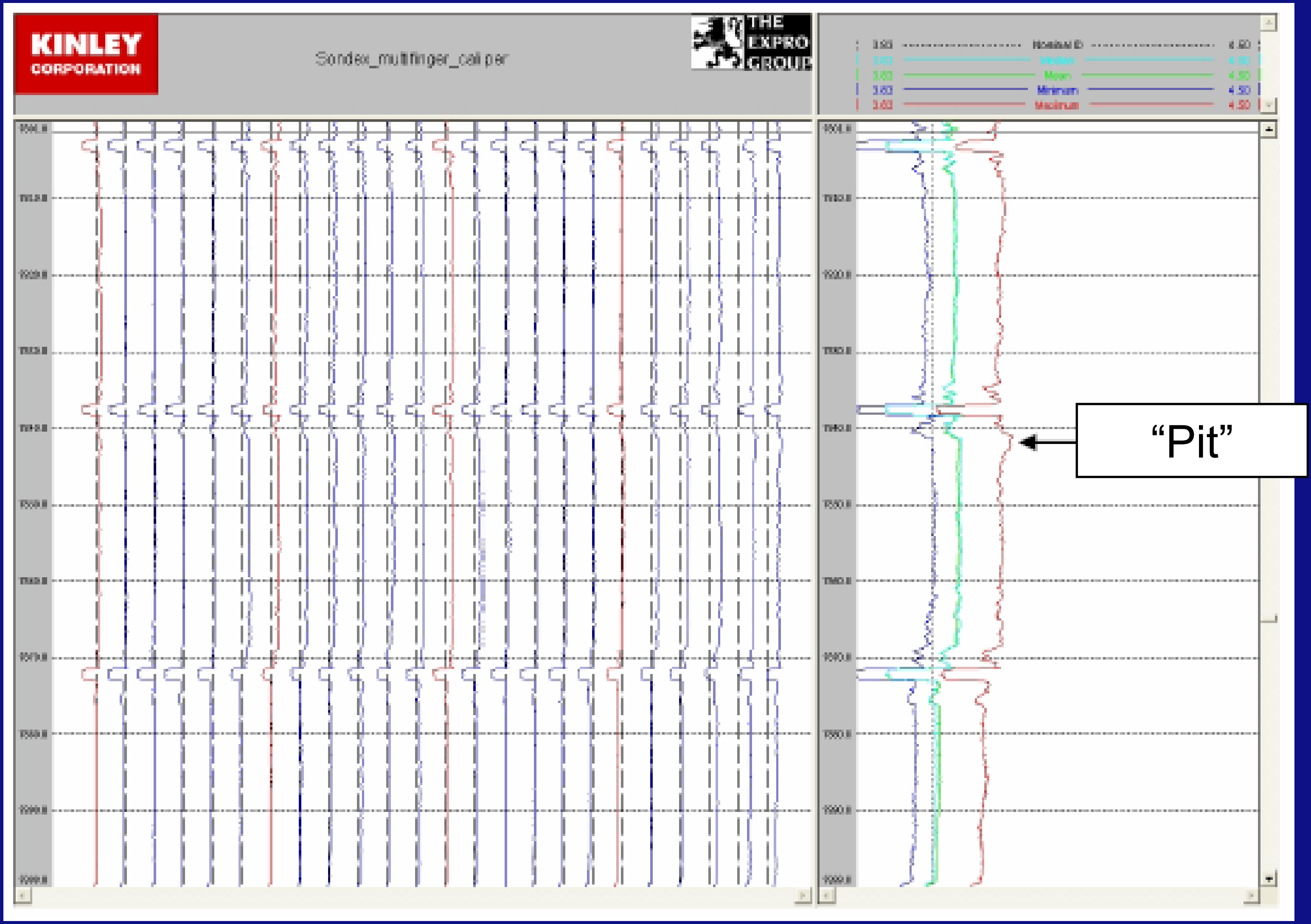
Well K12-B6 - Conditions

- In February 2005 the gas production well K12-B6 has been modified into a CO_2 injection well
- The reservoir temperature is 127 °C
- The original gas composition in the reservoir is sweet natural gas with 13% CO_2; no significant amounts of H_2S are present
- The production water contains up to 190.000 ppm chlorides
- For stainless steel these are very harsh conditions
- At the injection start and after one year of operation the condition of the production tubing has been inspected by caliper analysis

Temperatures and Pressures



Measurements: Multi-Finger Caliper Log

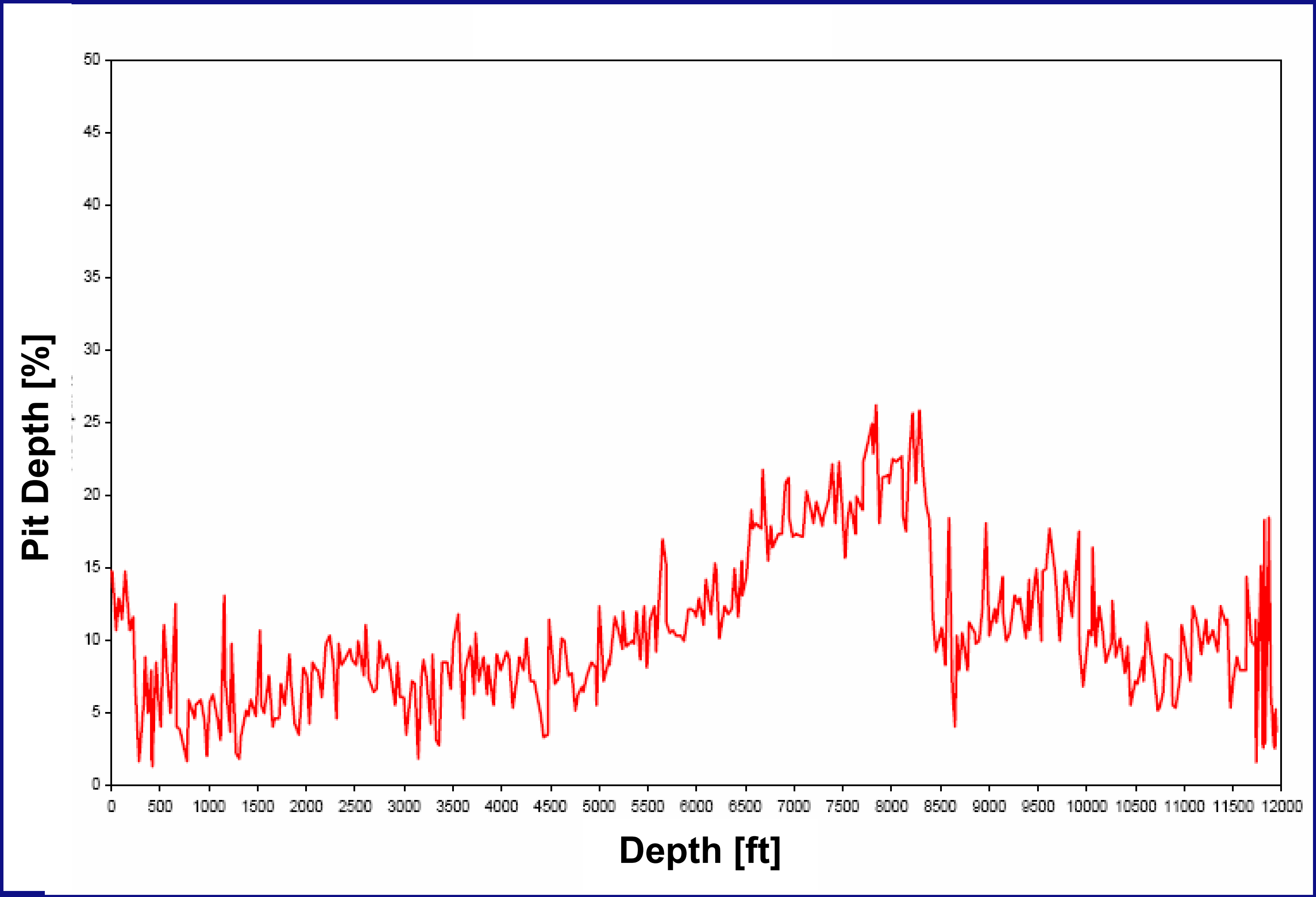


Well K12-B6, North Sea

Example of CO_2 corrosion

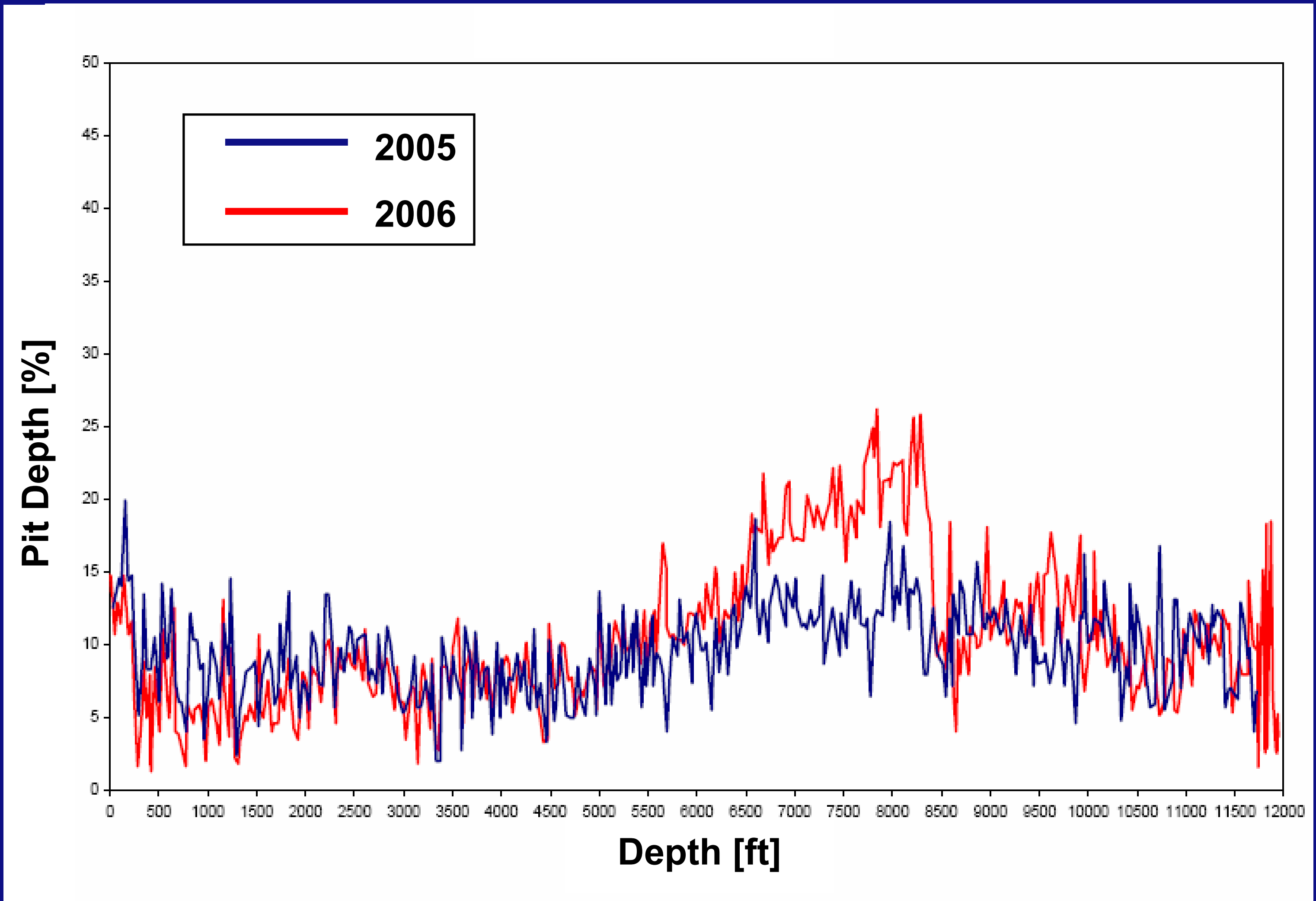
Well K12-B6, North Sea

Pit depth relative to tubing thickness in 2006…

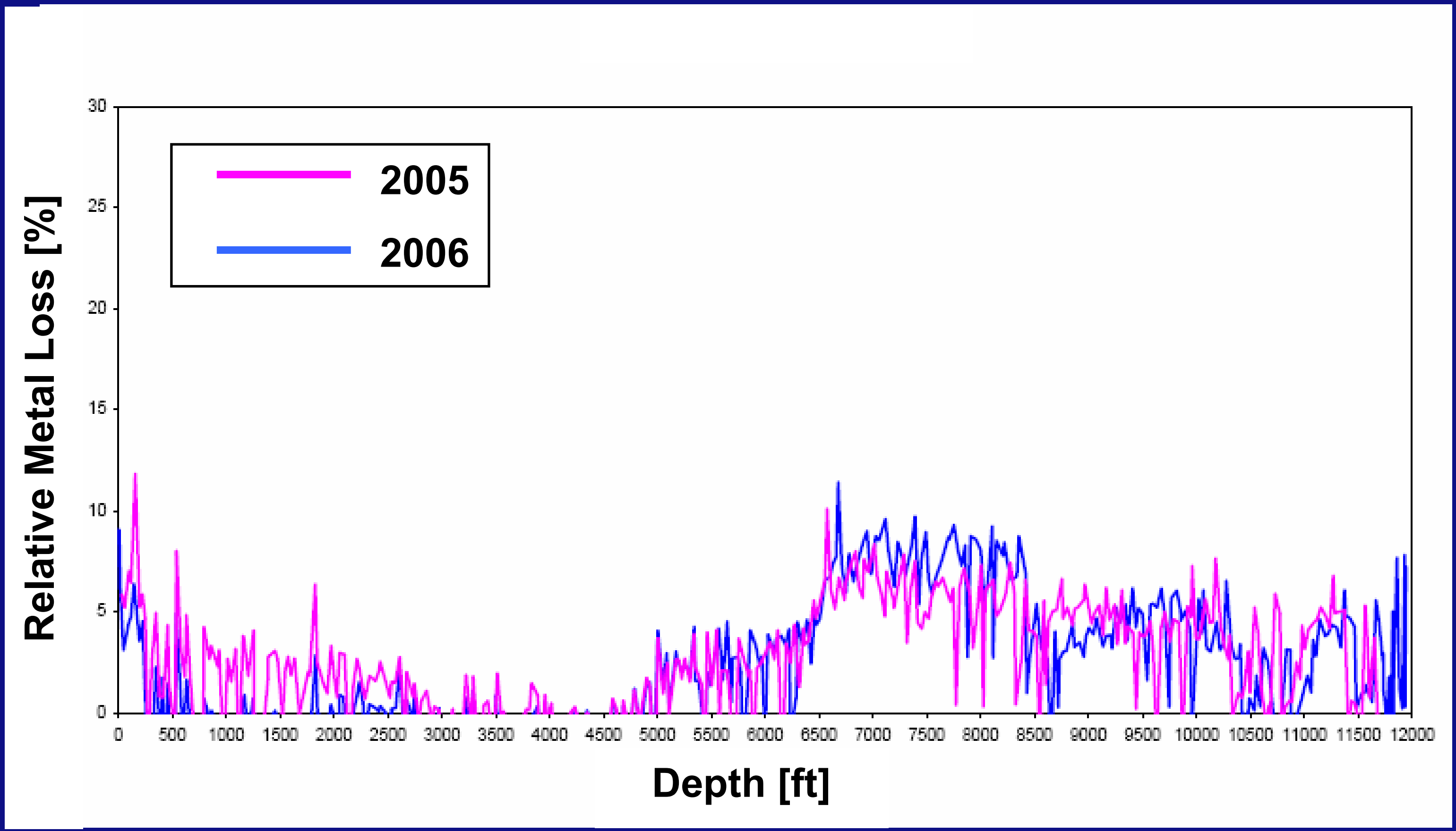


Well K12-B6, North Sea

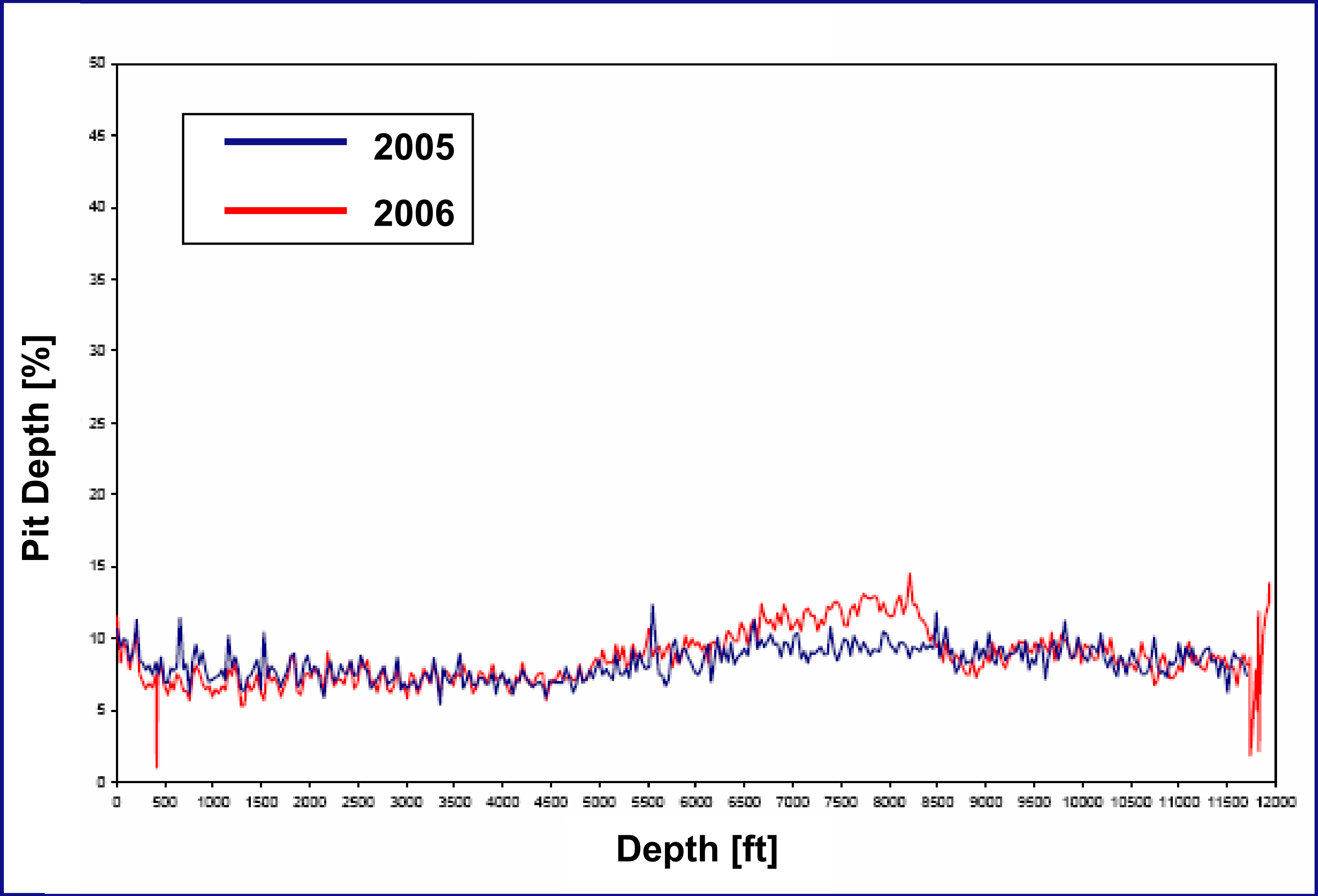
… and compared to 2005



Relative metal loss in 2006 and 2005



Pit depth relative to collar thickness



Possible Mechanisms

- Corrosion, eventually enhanced by
  - "splash zone" effect
  - high concentration of chloride-ions from the formation water
  - Metal particles in the injection fluid causing galvanic effects
- Damage of the passive oxide layer of the relatively weak chrome-tubing by relatively hard cables in the well
- Overtorque

Combinations of corrosion or erosion mechanisms usually cause a dramatic increase in the rate of metal loss compared to the summation of separate mechanisms

Acknowledgements

- GDF Production Nederland B.V. and partners
  - EXPRO North Sea
  - DRC
- Dutch Government (CRUST, CATO)
- European Commission (FP6, CASTOR, CO2GEONET)
- K12-B partners

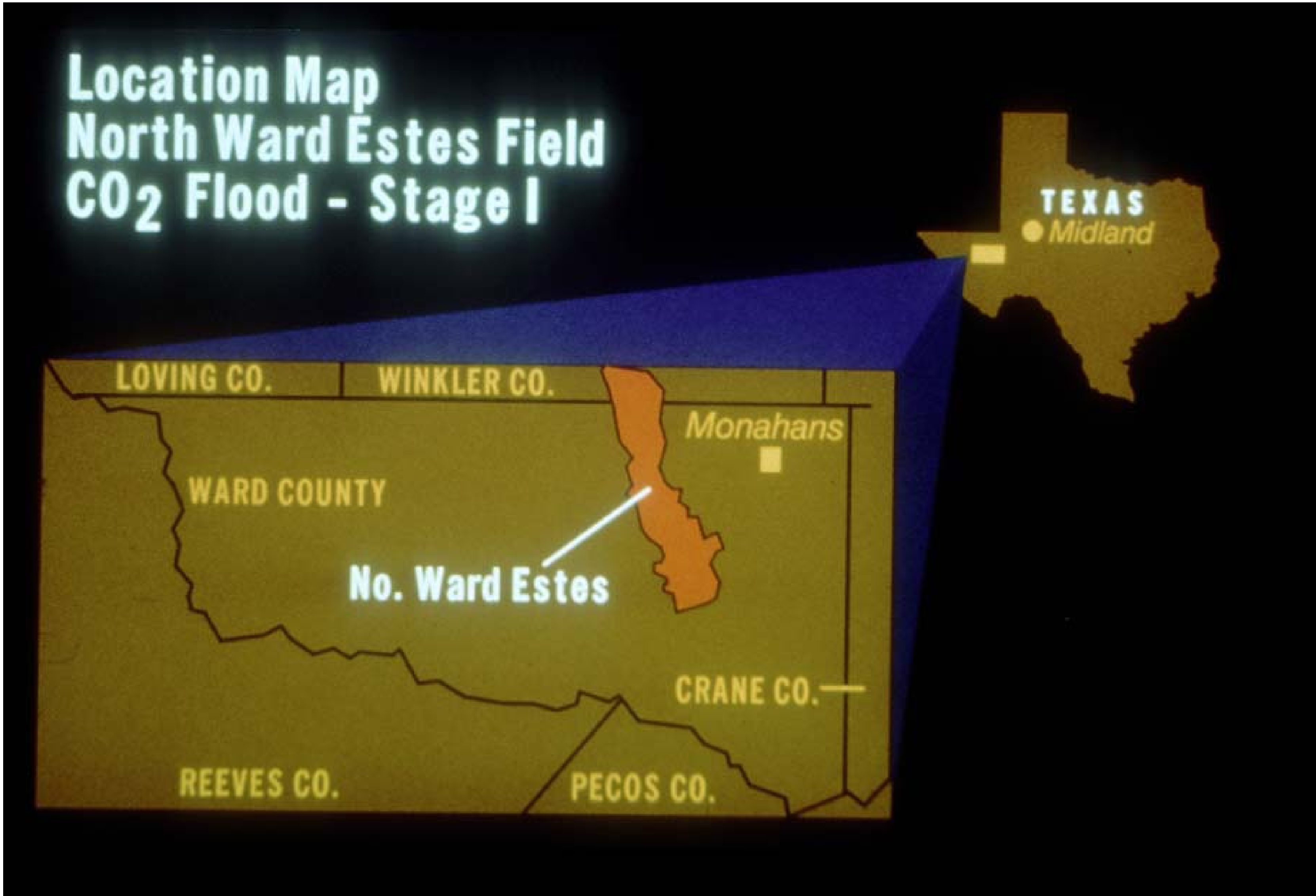
North Ward Estes

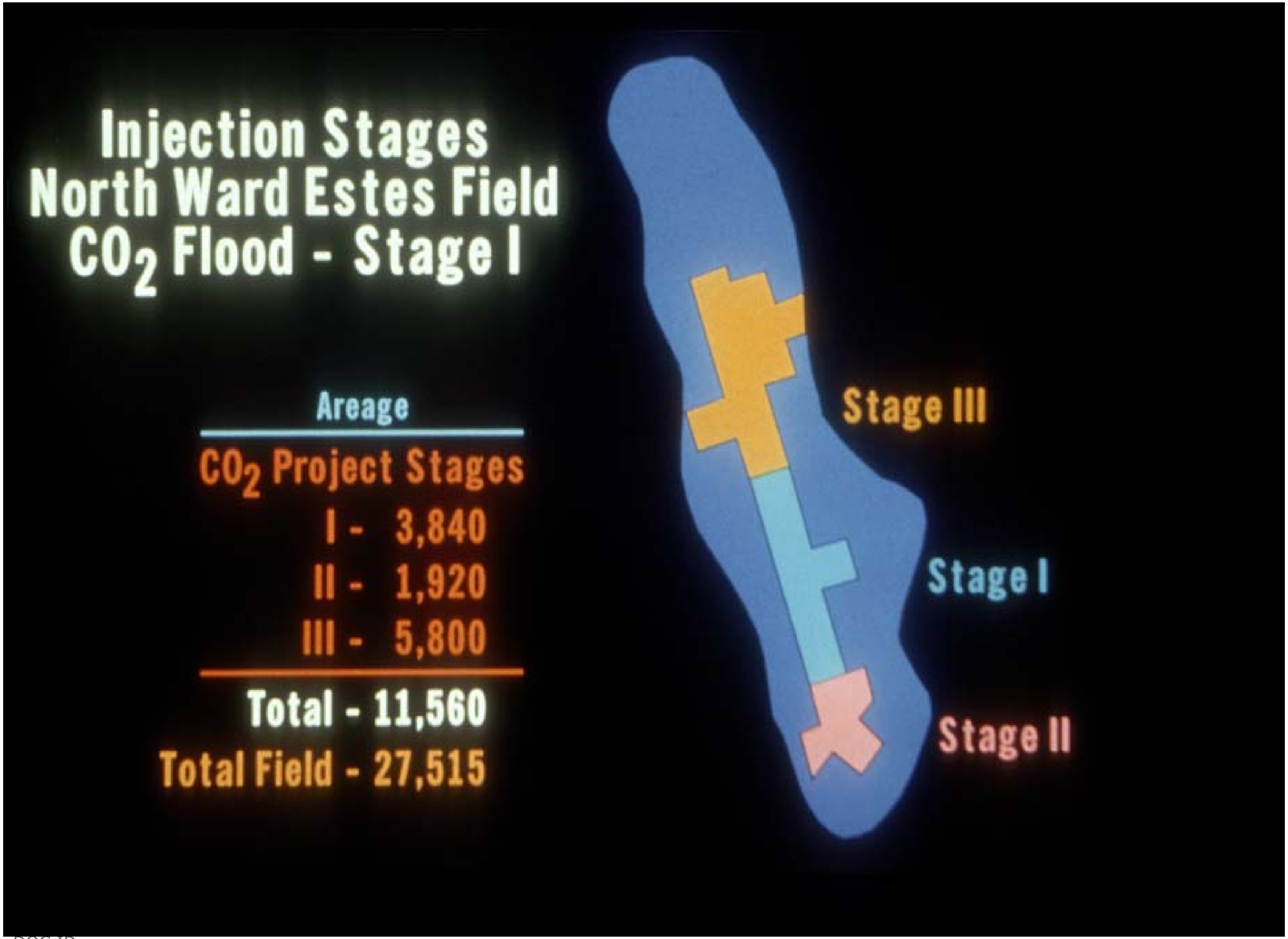
Converting Wells In A Mature West Texas Field For CO² Injection

Michael Power, Monte Leicht, and K.L. Barnett

SPE 20099
March 1990

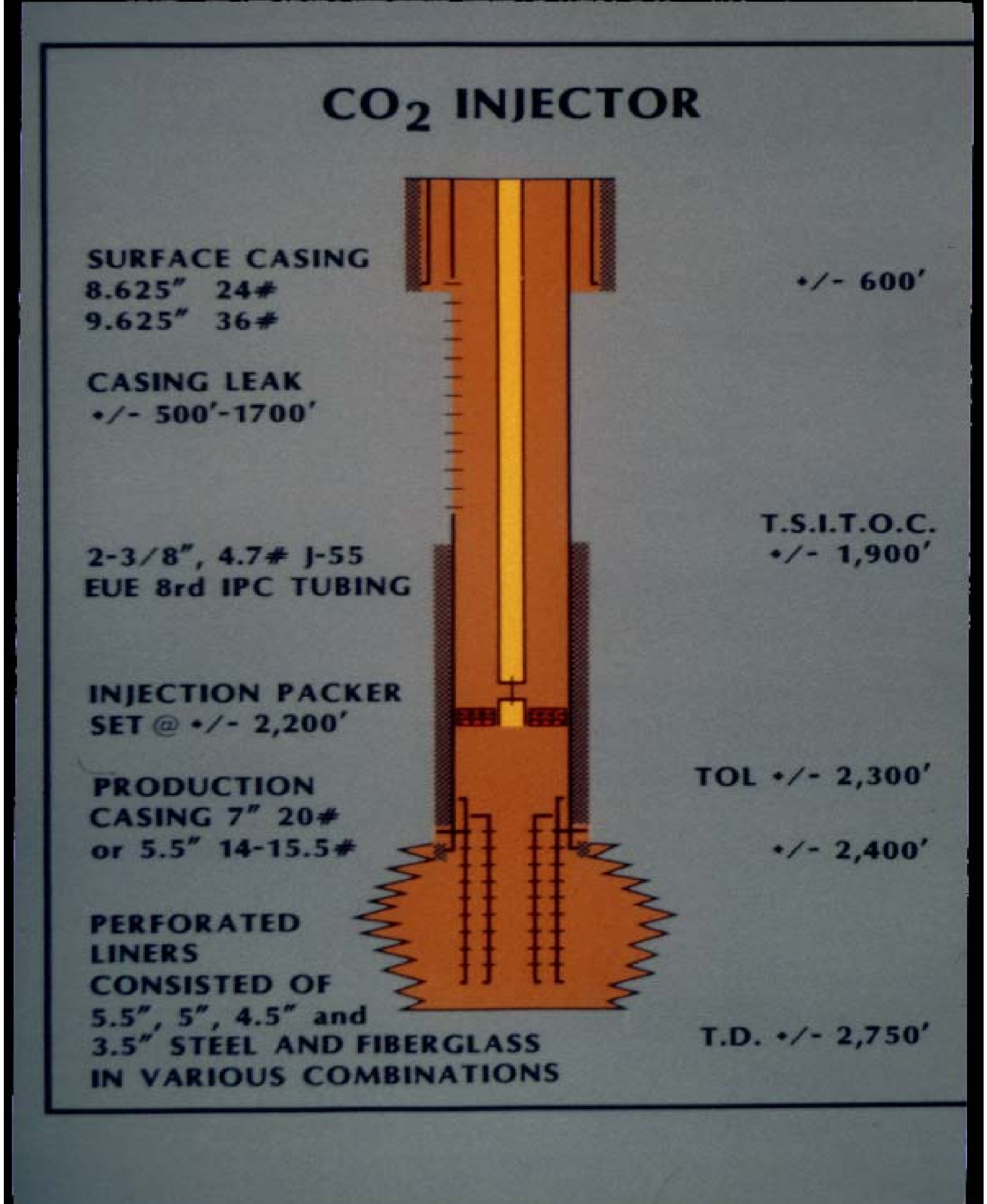
 DOC ID


Location Map
North Ward Estes Field
CO_2 Flood - Stage I
TEXAS
Midland
LOVING CO.
WINKLER CO.
Monahans
WARD COUNTY
No. Ward Estes
CRANE CO.
REEVES CO.
PECOS CO.


Injection Stages
North Ward Estes Field
CO_2 Flood - Stage I
Areage
CO_2 Project Stages
I - 3,840
II - 1,920
III - 5,800
Total - 11,560
Total Field - 27,515
Stage III
Stage I
Stage II

Four Types Of Wells Encountered

1. Nitro Shot Open Hole Injectors (60 Wells)
2. Open Hole Injectors (36 Wells)
3. Cased Hole Injectors With Plugback Requirements For Zonal Isolation (15 Wells)
4. Cased Hole Injectors With No Plugback Requirements (54 Wells)


CO2 INJECTOR
SURFACE CASING
8.625" 24#
9.625" 36#
+/- 600'
CASING LEAK
+/- 500'-1700'
T.S.I.T.O.C.
+/- 1,900'
2-3/8", 4.7# J-55
EUE 8rd IPC TUBING
INJECTION PACKER
SET @ +/- 2,200'
PRODUCTION
CASING 7" 20#
or 5.5" 14-15.5#
TOL +/- 2,300'
+/- 2,400'
PERFORATED
LINERS
CONSISTED OF
5.5", 5", 4.5" and
3.5" STEEL AND FIBERGLASS
IN VARIOUS COMBINATIONS
T.D. +/- 2,750'

NWE CO^2 Project Liner

Fishing Statistics

Open Hole Injectors 36

Nitro Shot Hole Injectors <u>60</u>

Total Open/Shot Hole Injectors 96

Average Depth +/- 2750'

Average Open Hole Length 300' – 400'

Wellbore Clean Out – 96 wells (fishing challenges)

Wells With FG Liner/Metal Outer Liner…8

Wells With 2 Metal Liners……………………33

Wells With 1 FG Liner…………………………25

Wells With 1 Metal Liner……………………..30

Recovery with Spear & Grapple

33 FG Liners – 24 Full Recovery (73%)

96 Metal Liners – 47 Partial Recovery (49%) – 91’ AVG – 2 Full Recovery (2%)

Recovery With Burning Shoe And Washpipe

Used on 66 Wells – 65% Recovery Per Run

Average Clean Out – 4.8 Days

Fishing Results

- Attempted clean out of 96 open hole wells
- 90 cleaned out for injection
- 6 wells required sidetracking


Gul

Casing Evaluation & Repair

- **Casing Inspection Logs – 20 wells confirmed consistent problems**
- **Squeeze Cementing – 31 wells; improved success from 55% to 84%**
- **Excavation and topside replacement – 17 wells excavated/repaired from 10’ to 80’**

Casing Remediation with Cement

- High Volume/Low Pressure (3-6 BPM w/200-500psi) utilize 2 slurry method
- Low volume/High Pressure (1/8- 1BPM w/800-1300psi) use single slurry
- Hesitation squeezing
- Extensive testing (i.e. rheology, pump time, compressive strength timeline)
- Batch mixer and pressurized mud balance

Improving Cementing Success

1. **Slurry Design –** ensure cement & additive quality; understand correlation of rheology & compressive strength properties
2. **Tools –** cement retainers & packers; plug cutters, cementing heads
3. **Technique –** hesitation squeezes; balanced plugs; stair step pressure
4. **Personnel –** knowledgeable & patient

Consequences Of Unsuccessful Squeezes

1. Run A Liner - $50,000 - $60,000
2. Drill A Replacement Well - $225,000
3. Plug And Abandon – Loss of Injection Support To Offset Producers

Tubing Recovered From Converted Wells

Joints Inspected - 11,299

Inspection Results

Yellow	Blue	Green	Silver	Red
5629	641	1285	887	2857
(49.8%)	(5.6%)	(11.4%)	(7.9%)	(25.3%)

Tubing Recovered And Reconditioned For Injection Use

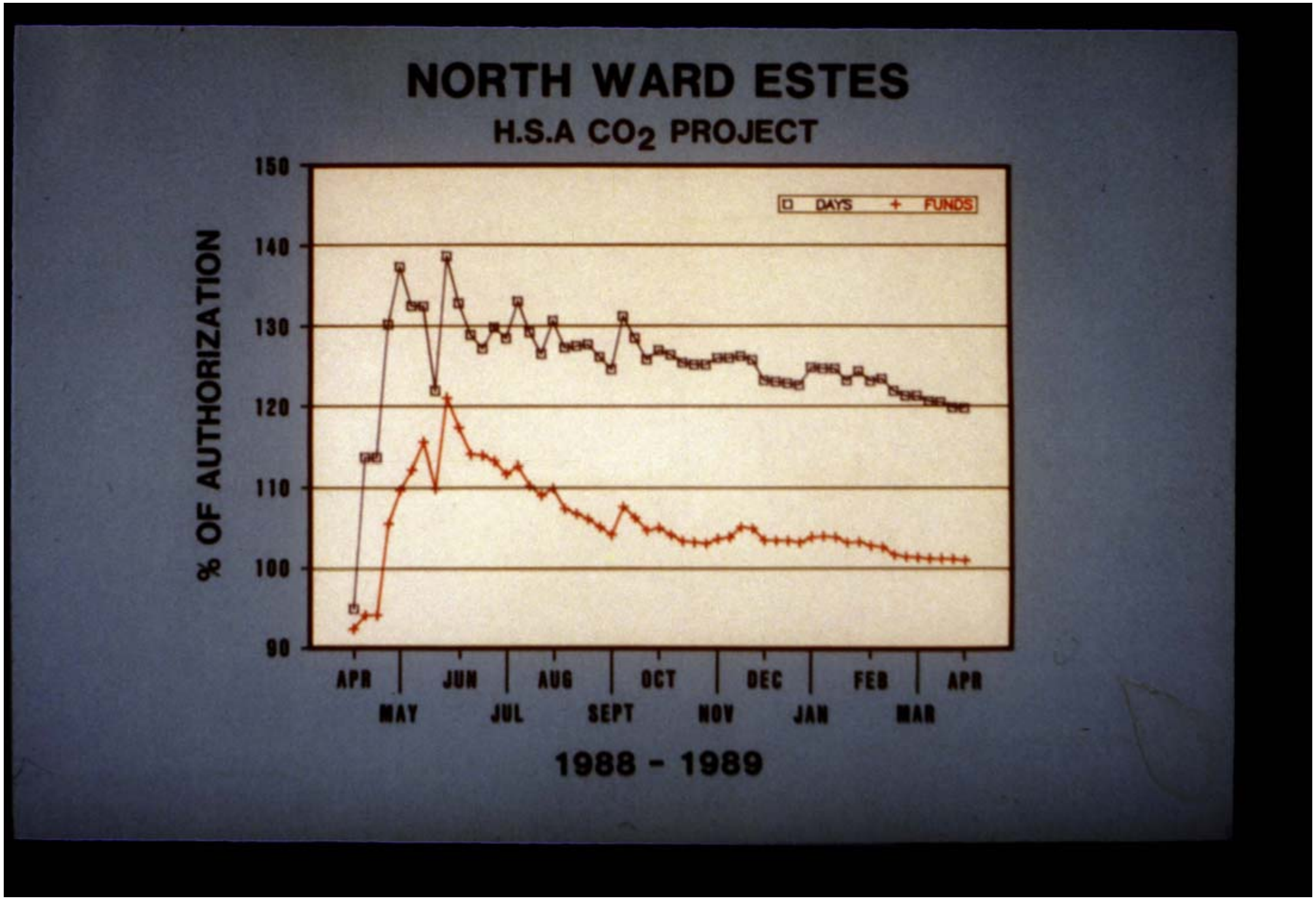
Yellow Band 4160 Joints

Blue-Green Band 1509 Joints

5669 Joints Reused As Injection Tubing

= 59.7% Of Rec. Tubing

Percentage of Authorized Days and Funds versus Project Timeline



CO2 Safety Issues

A slight increase in temperature can dramatically increase the pressure of CO2. Employees have to be aware of shutdowns and what temperature increases can do to their C02 process, and must have proper relief systems in place.

- **CO2 can be extremely corrosive if it contains any moisture.**
- **CO2 will freeze during pressure drops. When bleeding down lines employees must be aware of the possibility of the formation of ice plugs and trapped pressure.**
- **C02 will impregnate most rubbers, must have a management of change process for something as simple as changing O Rings to ensure like and kind replacement**
- **Pressurized CO2 lines inside of a city limit will be under the jurisdiction of the DOT**

Back Up

Slides

Stimulation

15% NEFE HCL

Scale Dissolving Solvent

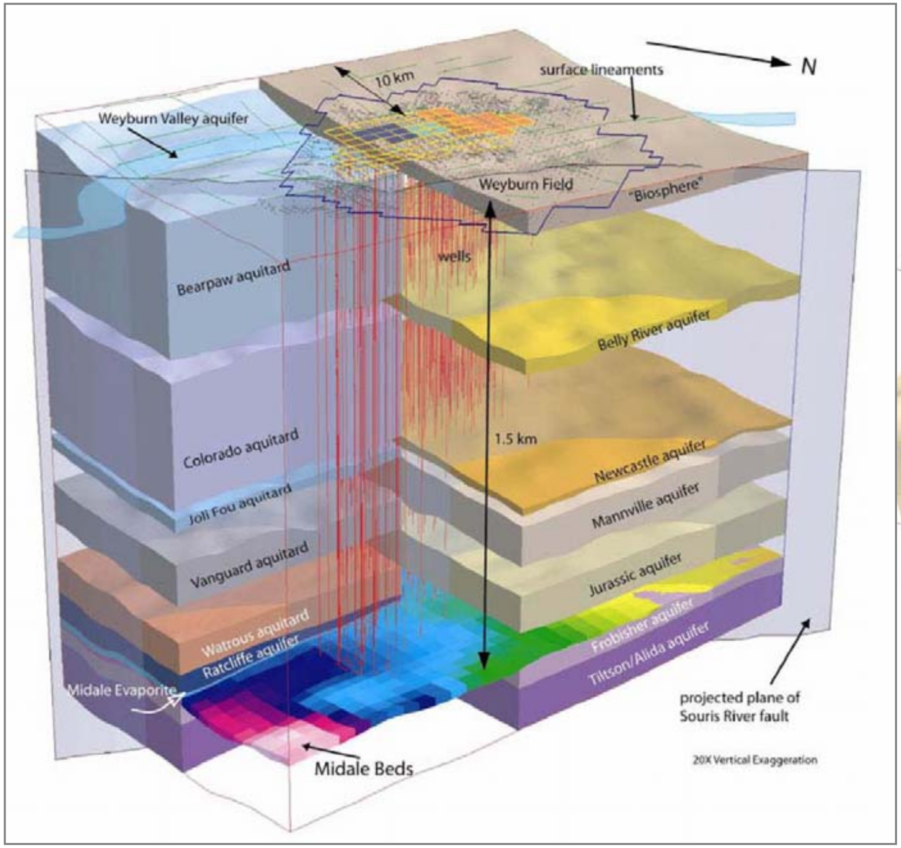
XYLENE

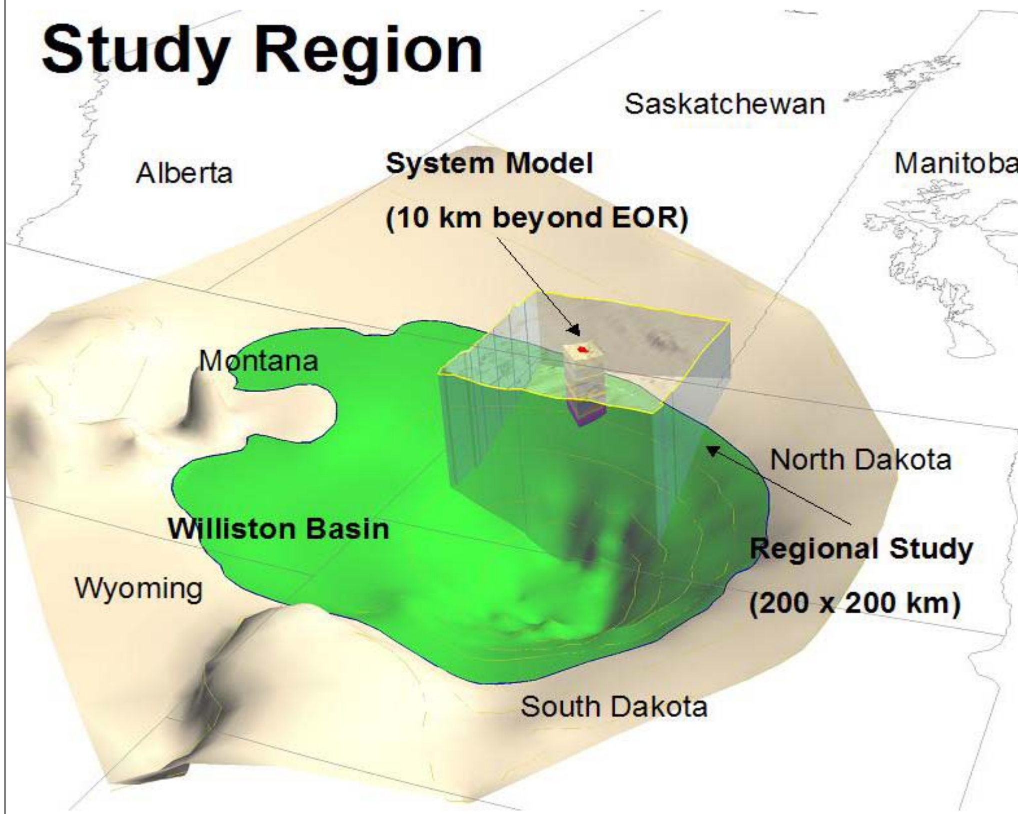
Micellar Solvent

Well Integrity Studies at the IEA Weyburn CO_2-EOR Monitoring and Storage Project

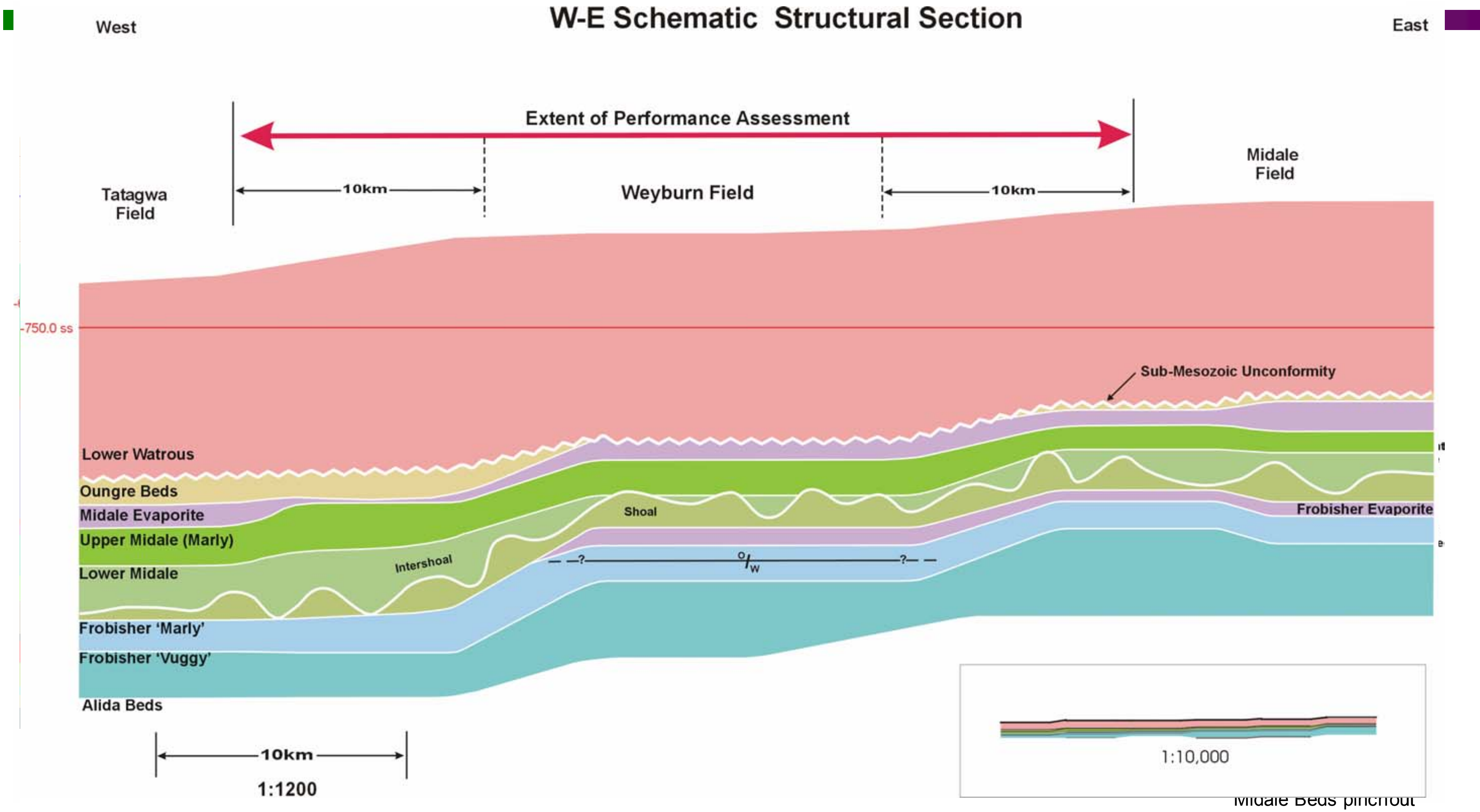
Rick Chalaturnyk
University of Alberta

Weyburn Setting

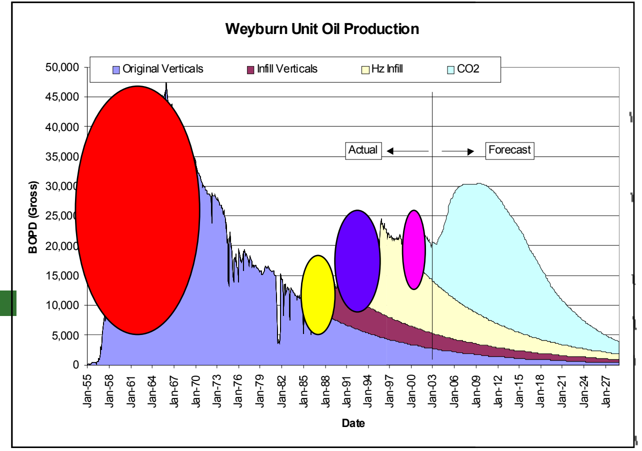


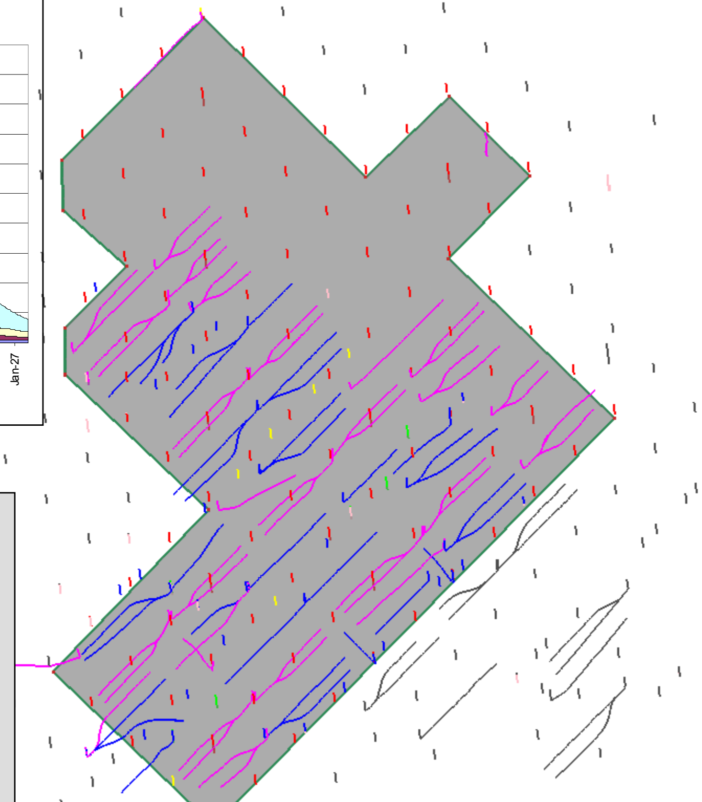


Weyburn CO_2 Storage System

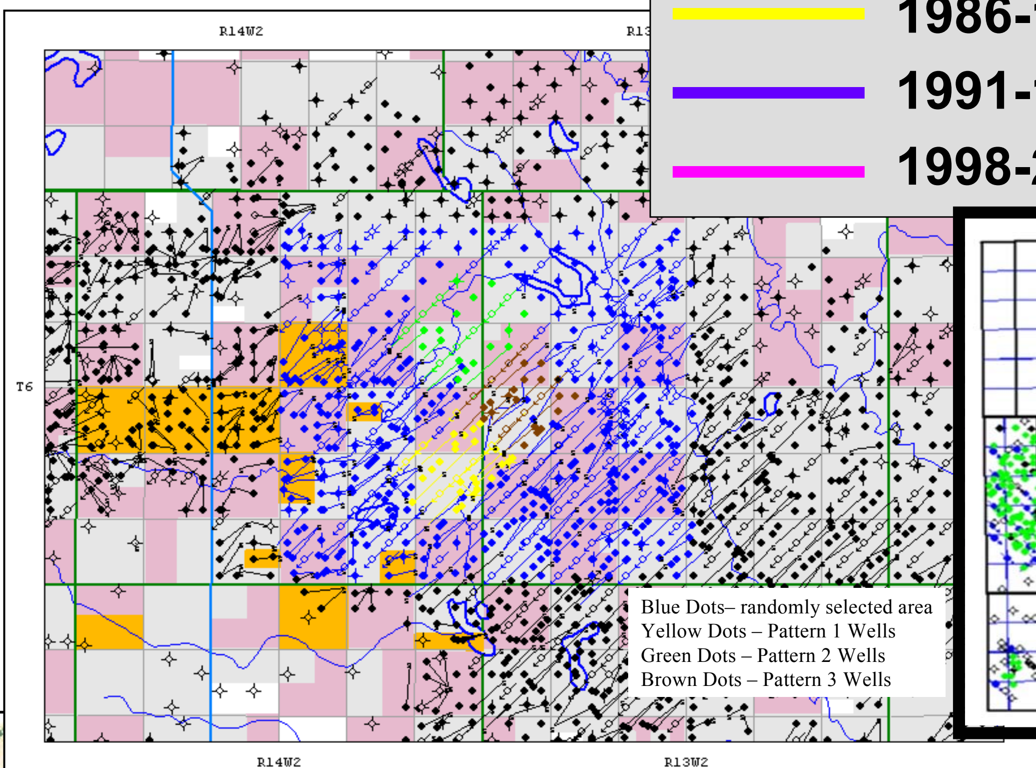


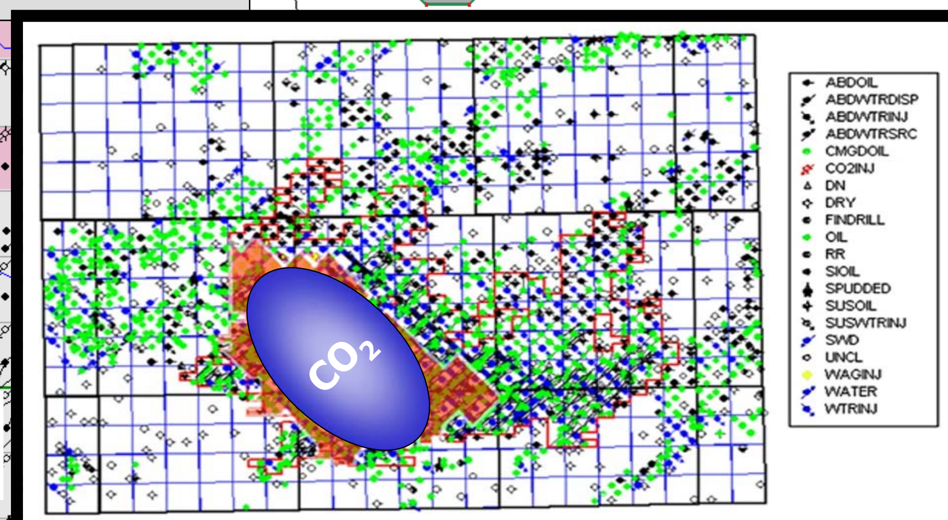
Wells in Phase 1a



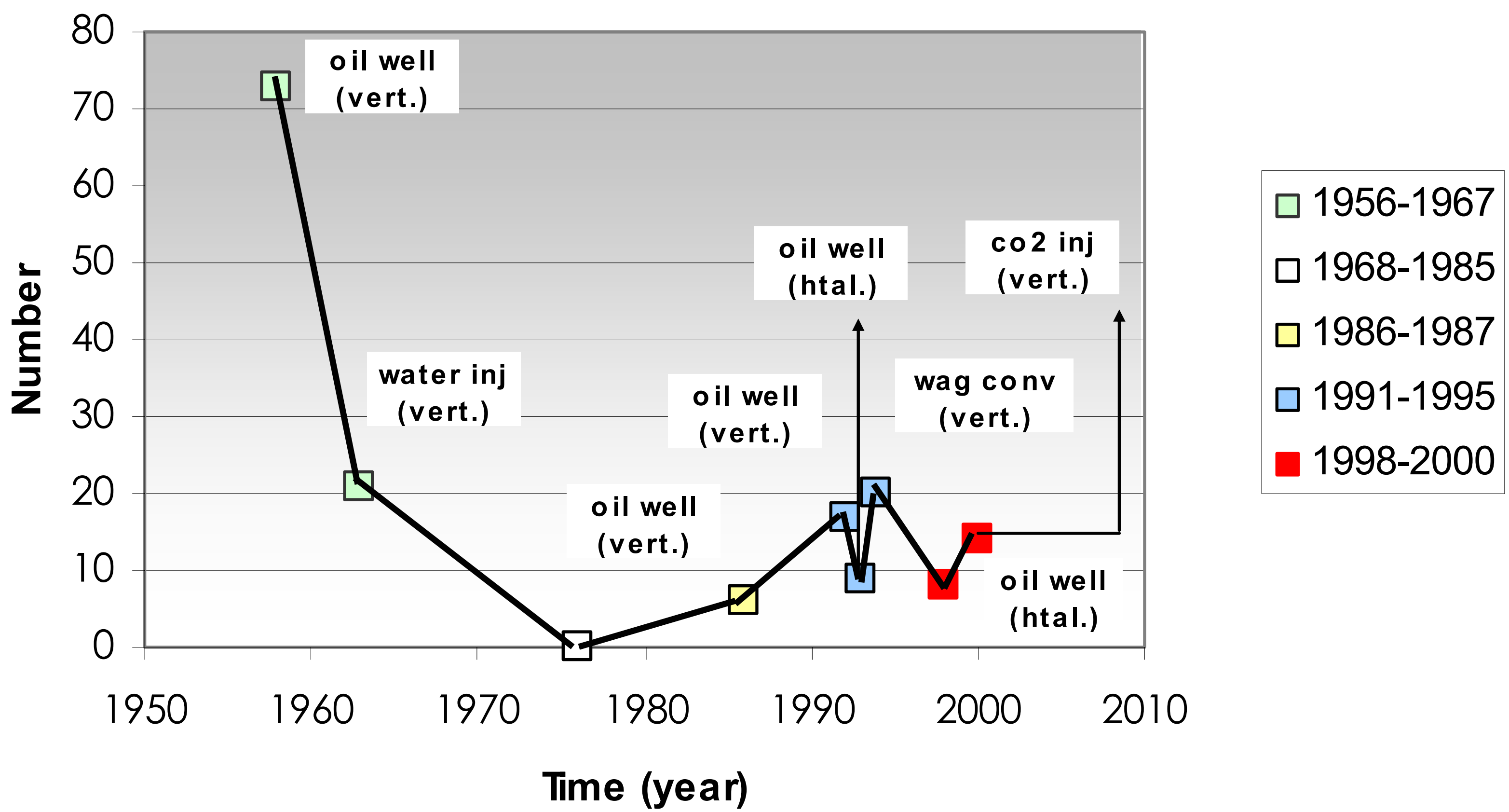


- 1956-1967
- 1986-1987
- 1991-1995
- 1998-2001





Statistics



Number
80
70
60
50
40
30
20
10
0
1950
1960
1970
1980
1990
2000
2010
Time (year)
oil well (vert.)
water inj (vert.)
oil well (vert.)
oil well (vert.)
oil well (htal.)
co2 inj (vert.)
wag conv (vert.)
oil well (htal.)
1956-1967
1968-1985
1986-1987
1991-1995
1998-2000

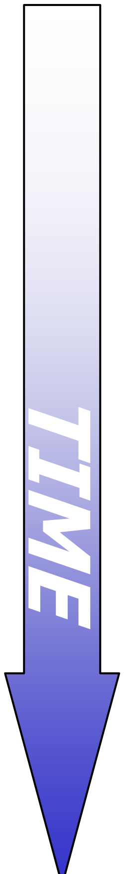
Elements of Well Integrity
Cement…

Failure Mode	Probability
Packer leak	$2.0\ 10^{-17}$
Major packer failure	$1.5\ 10^{-15}$
Injection tubing leak	$2.7\ 10^{-17}$
Major injection tubing failure	$2.1\ 10^{-8}$
Cement micro-annulus leak	$2.1\ 10^{-6}$
Confining zone(s) breach	$8.8\ 10^{-10}$
Inadvertent injection zone extraction	$6.6\ 10^{-7}$

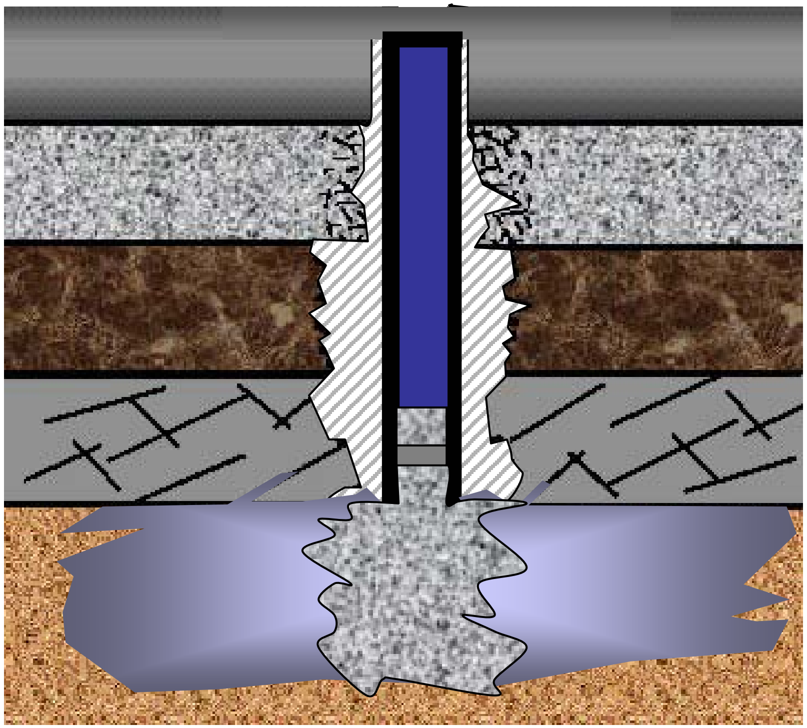
from Clark, J.E., An overview of injection well history in the United States, American Institute of Hydrology, 4th USA/CIS Joint Conference, Cathedral Hill Hotel, San Francisco, California, November 9, 1999.


17 1 2003

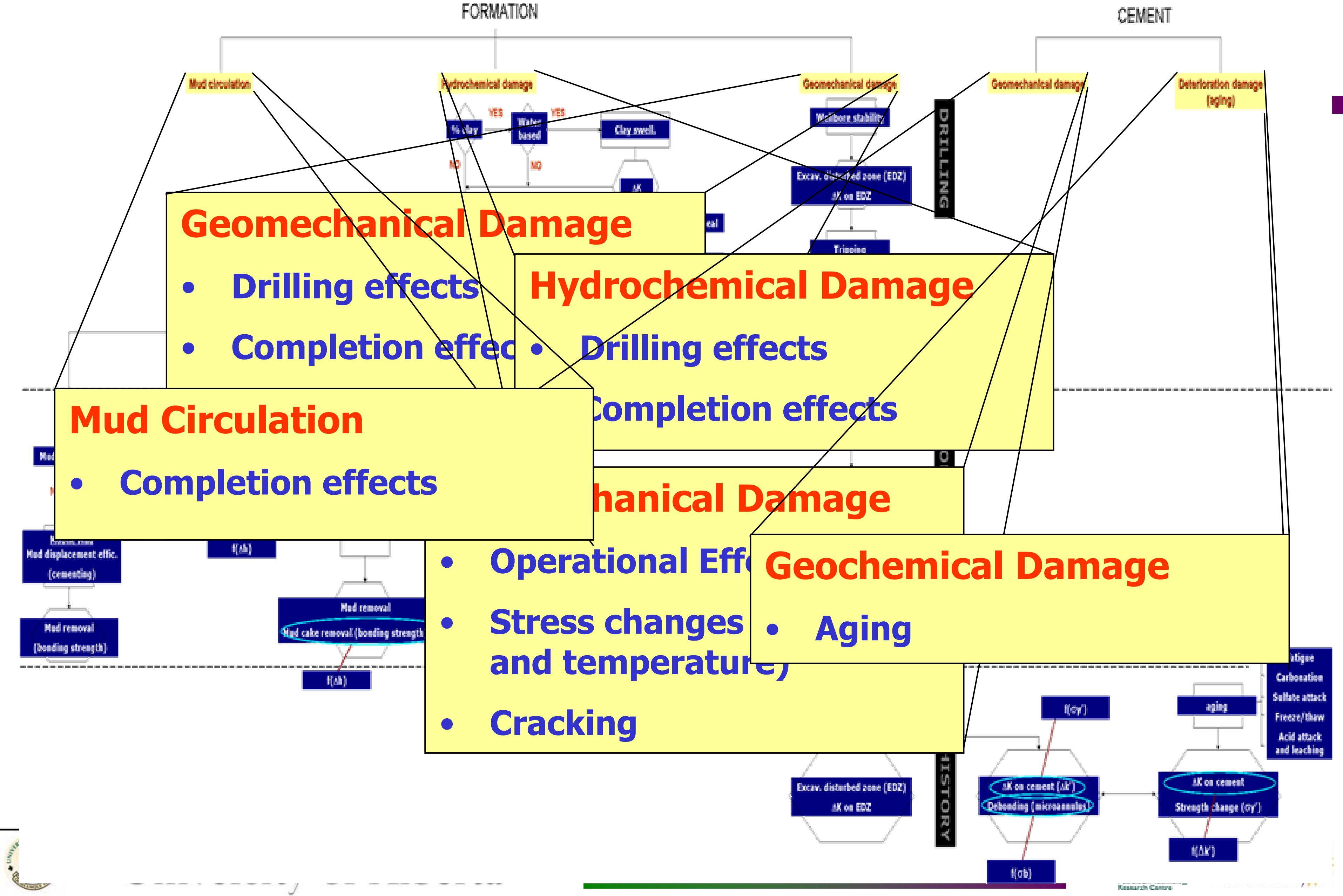
Elements of Well History Impacting Hydraulic Integrity



- Drilling
- Completion
- Production & Injection
- Abandonment



Well Integrity Assessment



Geomechanical Damage

- Drilling effects
- Completion effec

Hydrochemical Damage

- Drilling effects
- Completion effects

Mud Circulation

- Completion effects

hanical Damage

- Operational Eff
- Stress changes and temperature)
- Cracking

Geochemical Damage

- Aging

DETAILED SCHEMATIC FOR OIL WELL

UWI 101021300614W200

Spud Date:	
Period:	1956-1967
Type:	VCAL
Purpose	OIL WELL

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**	100.00		19.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**6.50**

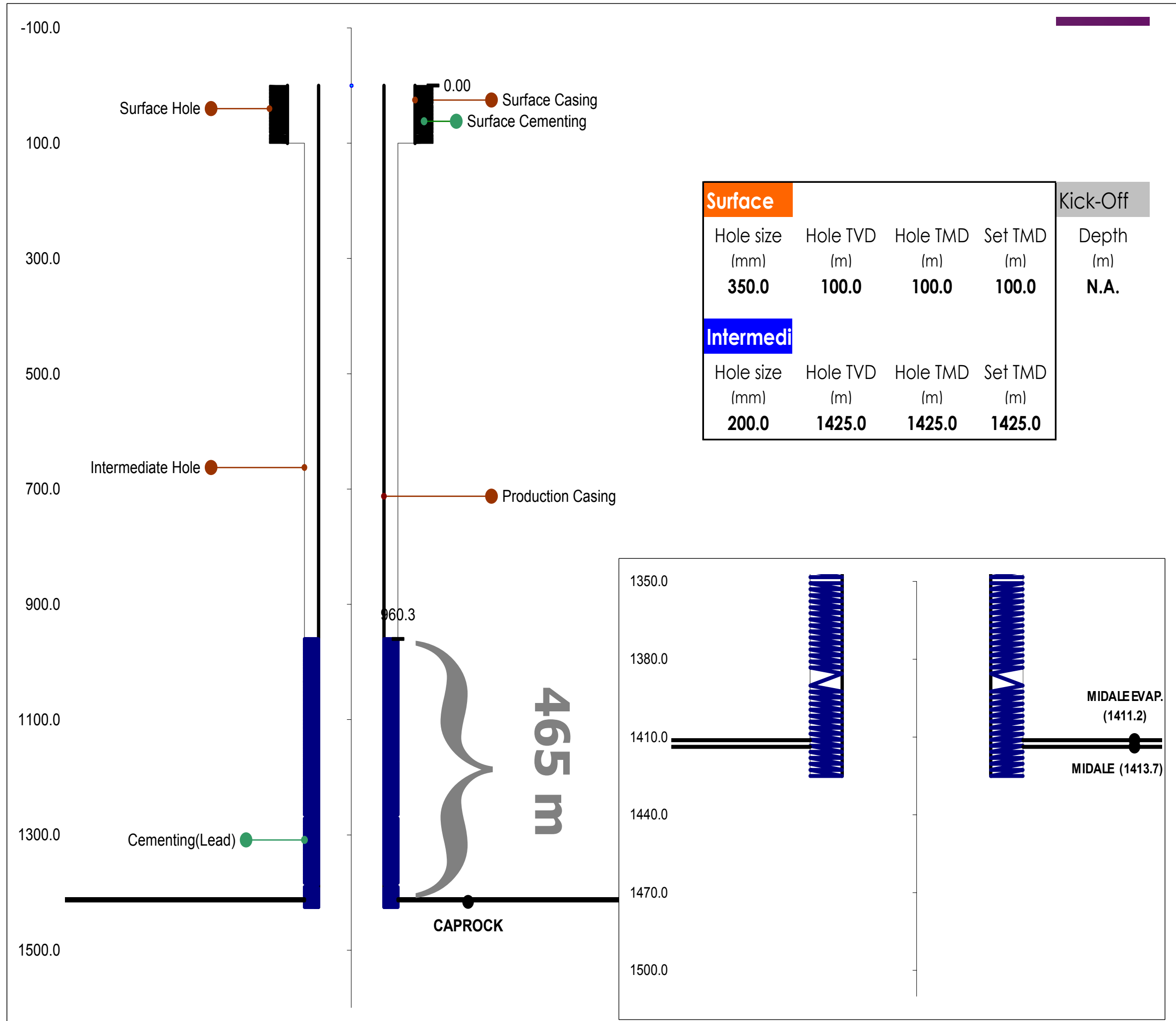
Intermediate Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
139.70	**J-55**	1425.00		10.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**7.50**



Surface				Kick-Off
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Depth (m)
350.0	**100.0**	**100.0**	**100.0**	**N.A.**

Intermedi			
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)
200.0	**1425.0**	**1425.0**	**1425.0**

DETAILED SCHEMATIC FOR WATER INJECTION WELL

UWI: 101062400614W200

Spud Date:
Period: 1956-1967
Type: VCAL
Purpose: WATER INJECTOR

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**	100.00		19.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**6.50**

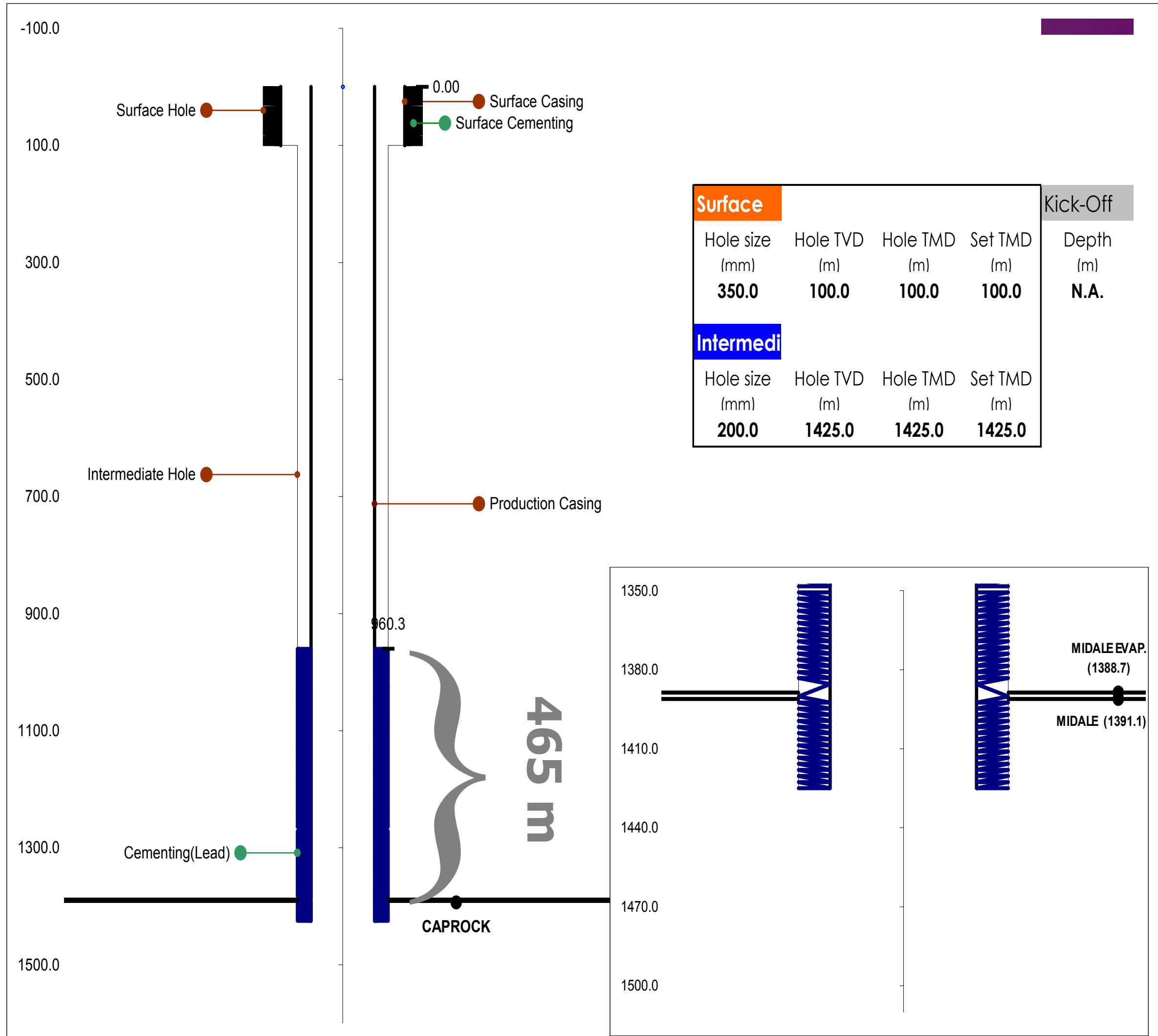
Intermediate Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
139.70	**J-55**	1425.00		10.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**7.50**



Surface				Kick-Off
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Depth (m)
350.0	**100.0**	**100.0**	**100.0**	**N.A.**
Intermedi				
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	
200.0	**1425.0**	**1425.0**	**1425.0**	

DETAILED SCHEMATIC FOR WAG INJECTION WELL

UWI: 101041900613W200

Spud Date:

Period: 1956-1967

Type: VCAL

Purpose: WAG INJECTOR

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**	100.00		19.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**5.00**

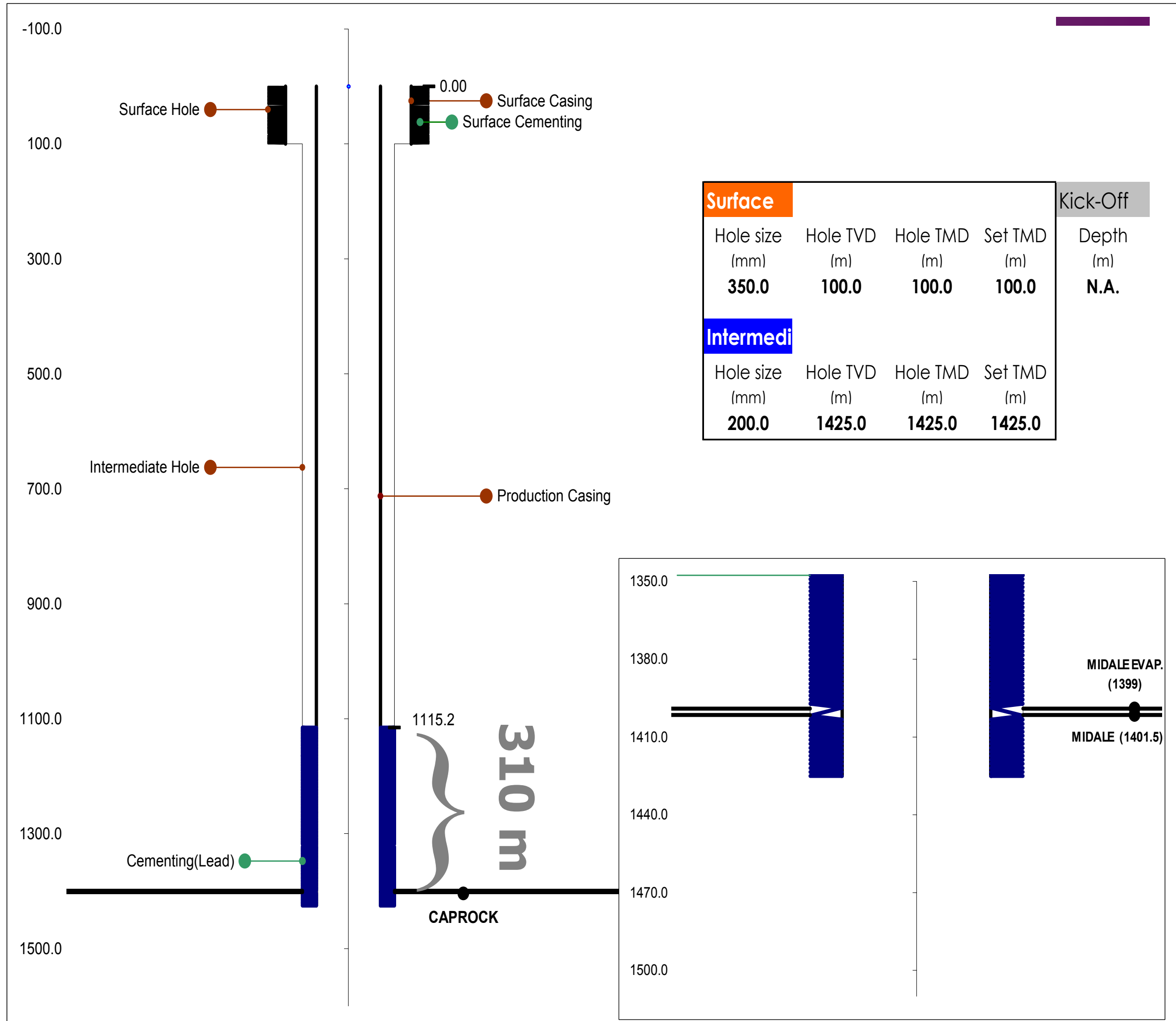
Intermediate Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
139.70	**J-55**	1425.00		10.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**5.00**



Surface	Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Kick-Off Depth (m)
	350.0	**100.0**	**100.0**	**100.0**	**N.A.**
Intermedi	**Hole size (mm)**	**Hole TVD (m)**	**Hole TMD (m)**	**Set TMD (m)**	
	200.0	**1425.0**	**1425.0**	**1425.0**	

DETAILED SCHEMATIC FOR ABANDONED OIL WELL

UWI	101023500614W200
Spud Date:	
Period:	1956-1967
Type:	VCAL
Purpose	OIL WELL (ABANDONED)

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**	100.00		8.00

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**5.00**

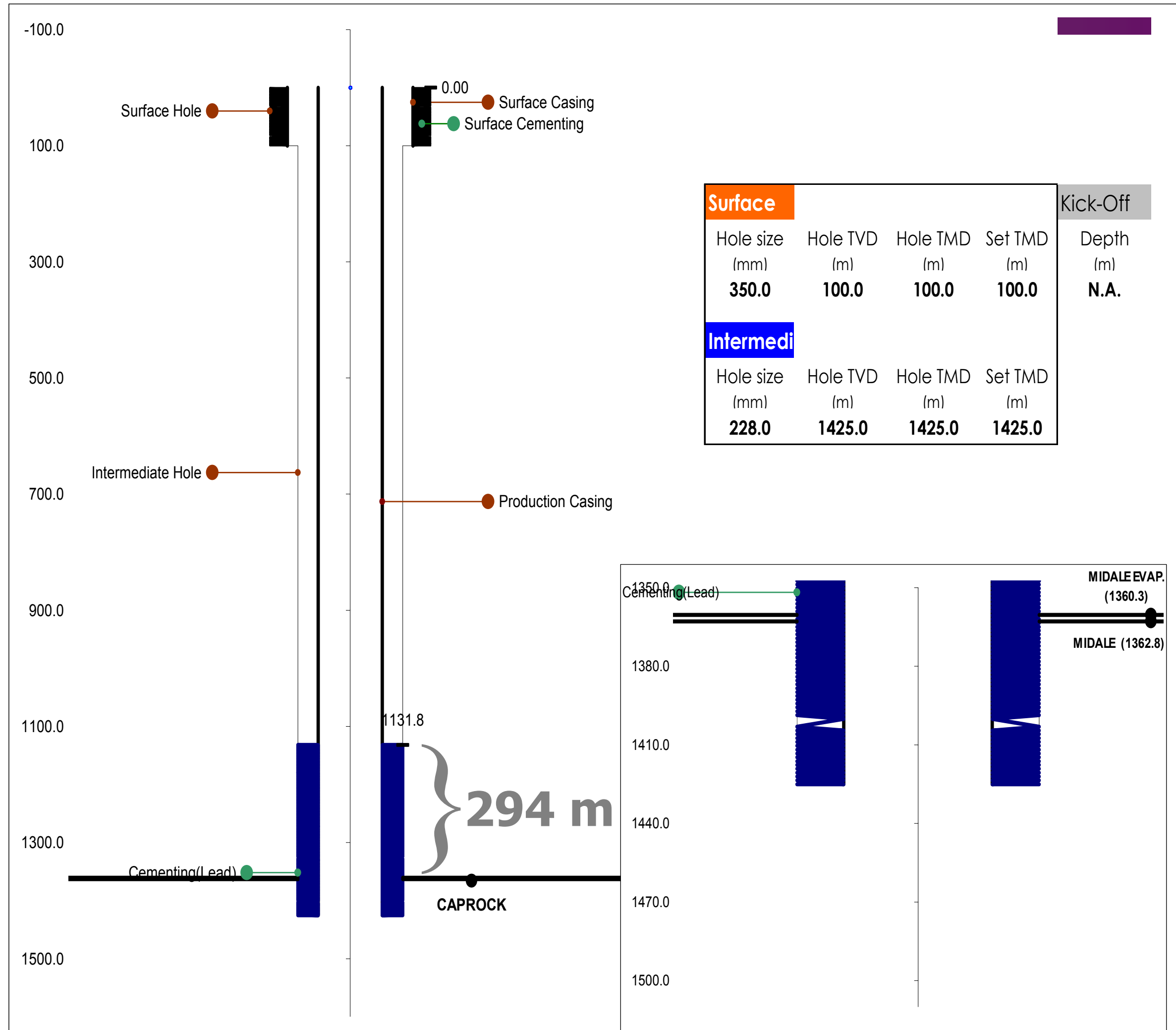
Intermediate Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
139.70	**J-55**	1425.00		8.00

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**7.50**



Surface				Kick-Off
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Depth (m)
350.0	**100.0**	**100.0**	**100.0**	**N.A.**
Intermedi				
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	
228.0	**1425.0**	**1425.0**	**1425.0**	

DETAILED SCHEMATIC FOR CO_2 INJECTION WELL

UWI 193101200614w200

Spud Date:
Period: 1998-2001
Type: HTAL
Purpose CO2 INJECTOR

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
244.50	**H-40**	140.00		16.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**14.00**

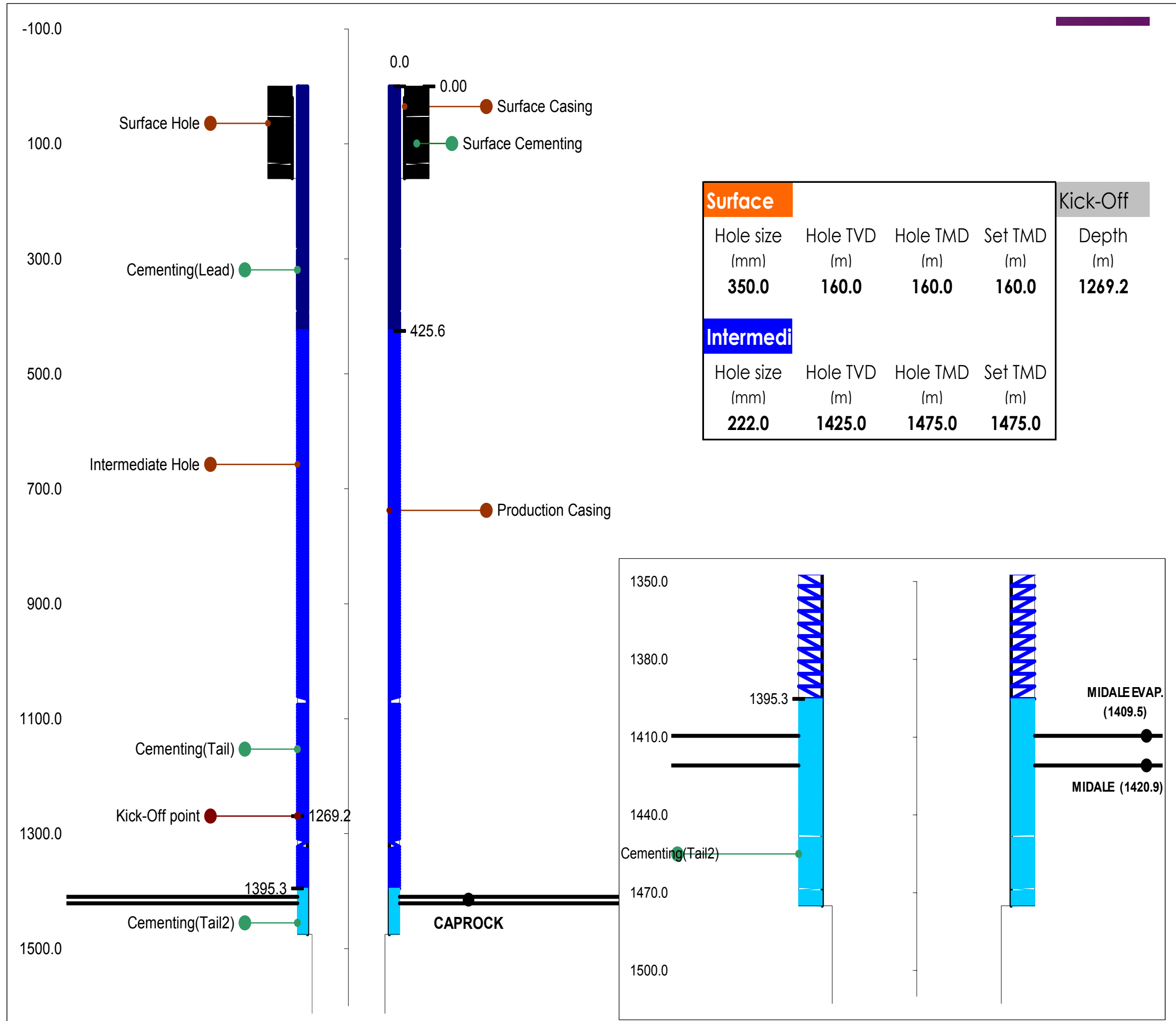
Intermediate Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
177.80	**J-55**	1475.00		13.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**18.00**
	TAIL		**13.50**
	TAIL2		**1.11**



Surface				Kick-Off
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Depth (m)
350.0	**160.0**	**160.0**	**160.0**	**1269.2**
Intermedi				
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	
222.0	**1425.0**	**1475.0**	**1475.0**	

DETAILED SCHEMATIC FOR CO_2 PRODUCTION WELL

UWI 92071100614w200

Spud Date:

Period: 1998-2001

Type: HTAL

Purpose OIL WELL (PUMPING)

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
244.50	**H-40**	140.00		19.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**14.00**

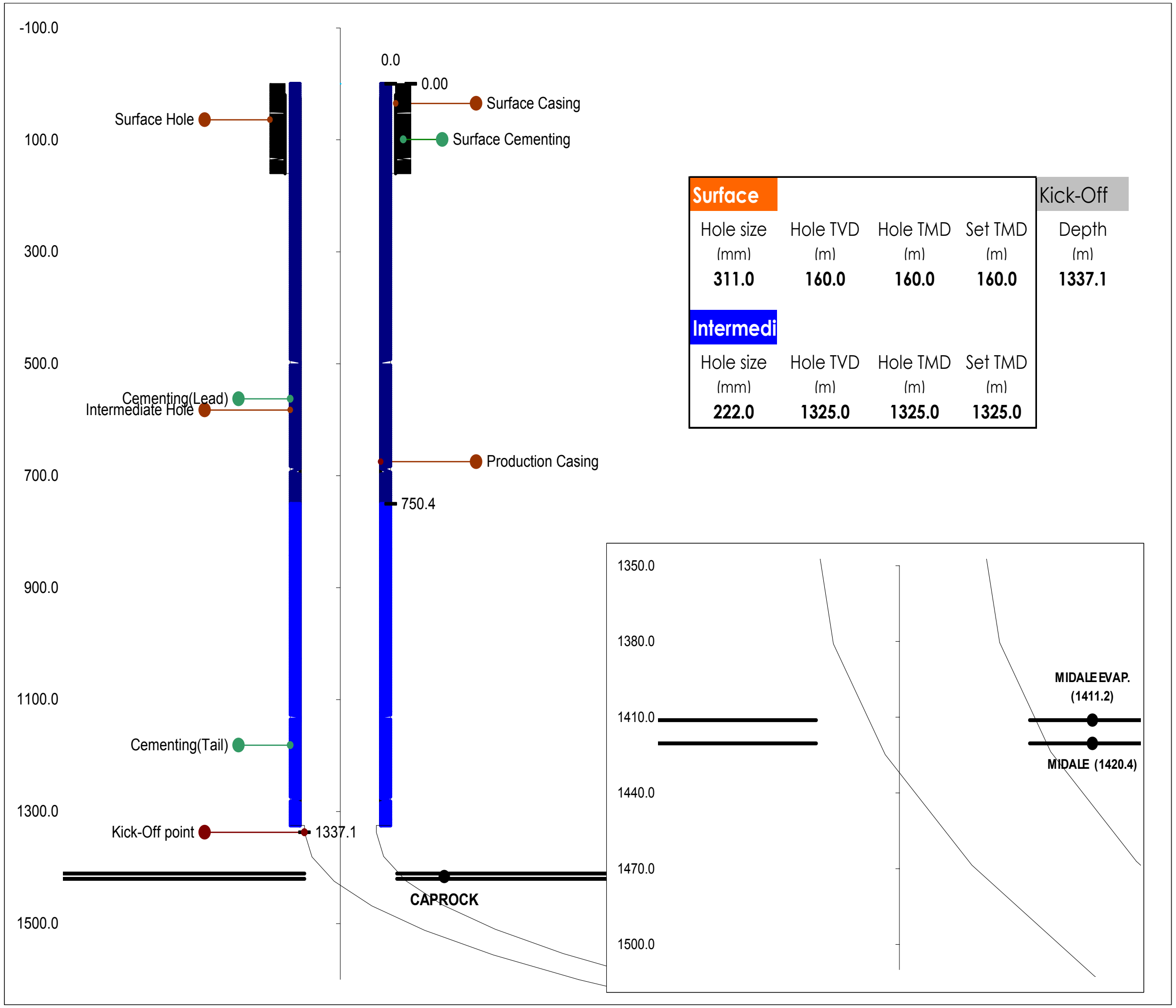
Intermediate Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
177.80	**J-55**	1300.00		13.50

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD		**18.00**
	TAIL		**8.00**



Abandoned Wells

UWI 101141800613W200

Spud Date: 5/19/1957
Period: 1956-1967
Type: VCAL
Purpose OIL WELL (ABANDONED)

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	H-40		9	

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
(PORTLAND)+2%CACL2	LEAD	200 SACKS	5.66

Intermediate Information

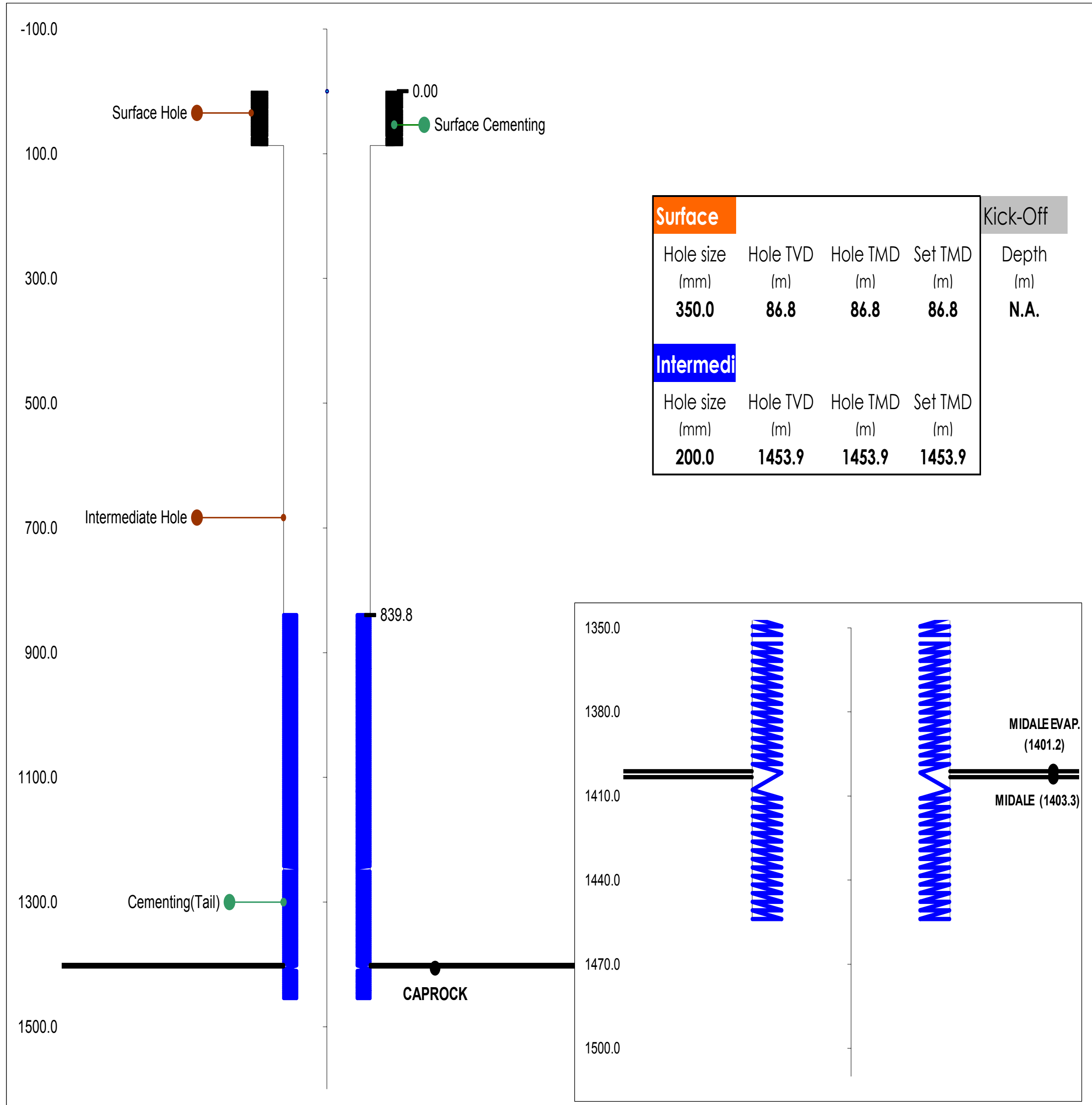
Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
139.70	J-55		148	

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
(ROXLITE)+2%GEL	TAIL	350 CU FT.	9.91

H-40	Recorded in Wellfile
18.10	Computed from data in Wellfiel



Surface	Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Kick-Off Depth (m)
	350.0	86.8	86.8	86.8	N.A.

Intermedi	Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)
	200.0	1453.9	1453.9	1453.9

UWI 101121800613W200

Spud Date:	2/8/1957
Period:	1956-1967
Type:	VCAL
Purpose	(ABANDONED)

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**	98.50	10	

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
(PORTLAND)+2%CACL2	**LEAD**	**200 SACKS**	**5.66**

Intermediate Information

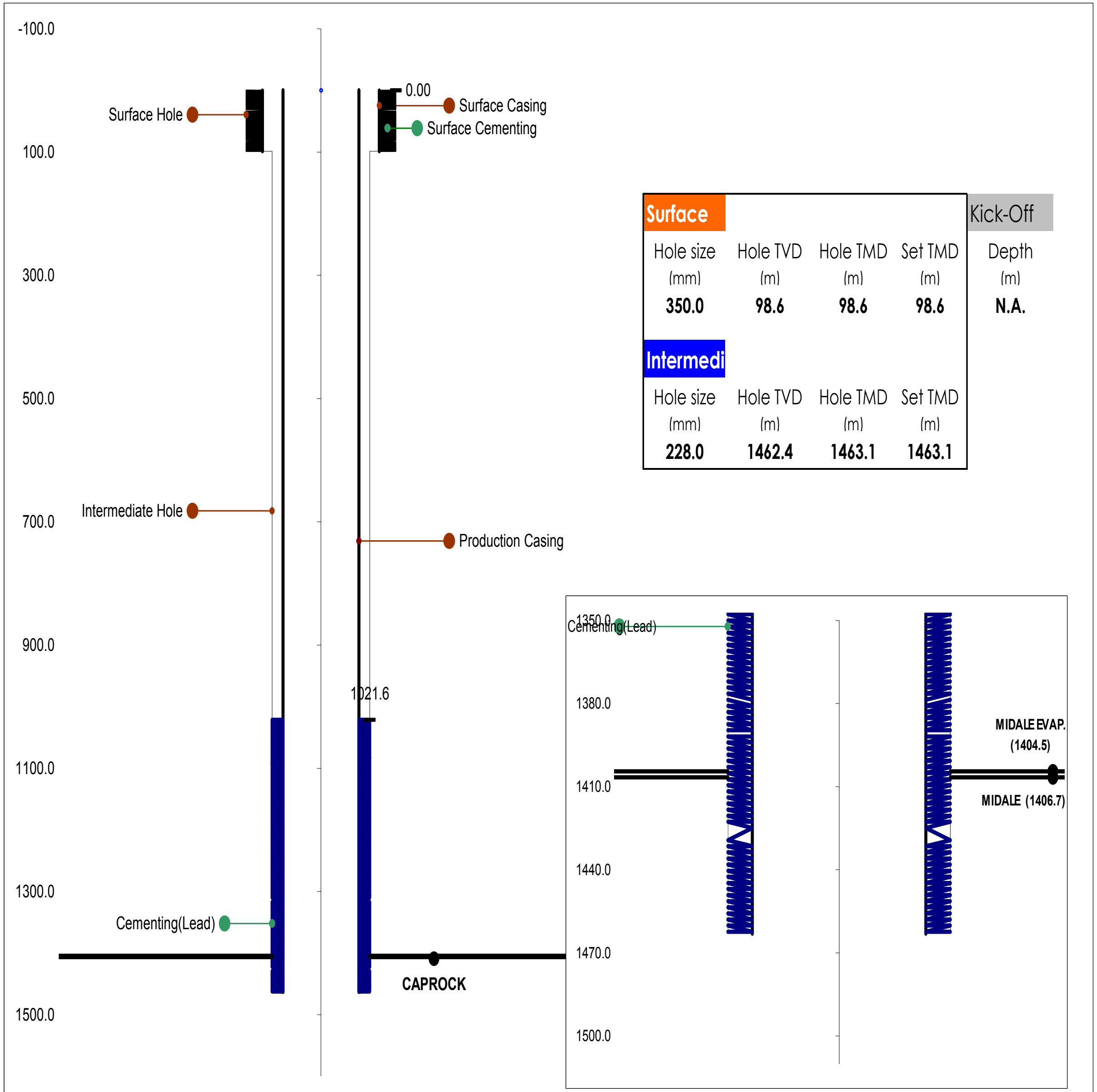
Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
177.80	**J-55**	1463.60	53	

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
(POZMIX)+2%GEL	**LEAD**	**250 SACKS**	**7.08**

H-40 Recorded in Wellfile
18.10 Computed from data in Wellfiel



Surface	Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Kick-Off Depth (m)
	350.0	**98.6**	**98.6**	**98.6**	**N.A.**

Intermedi	Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)
	228.0	**1462.4**	**1463.1**	**1463.1**

UWI 101081200614W200

Spud Date: 11/17/1957
Period: 1956-1967
Type: VCAL
Purpose OIL WELL (ABANDONED)

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**		9	

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
(PORTLAND)	**LEAD**	**200 SACKS**	**5.66**

Intermediate Information

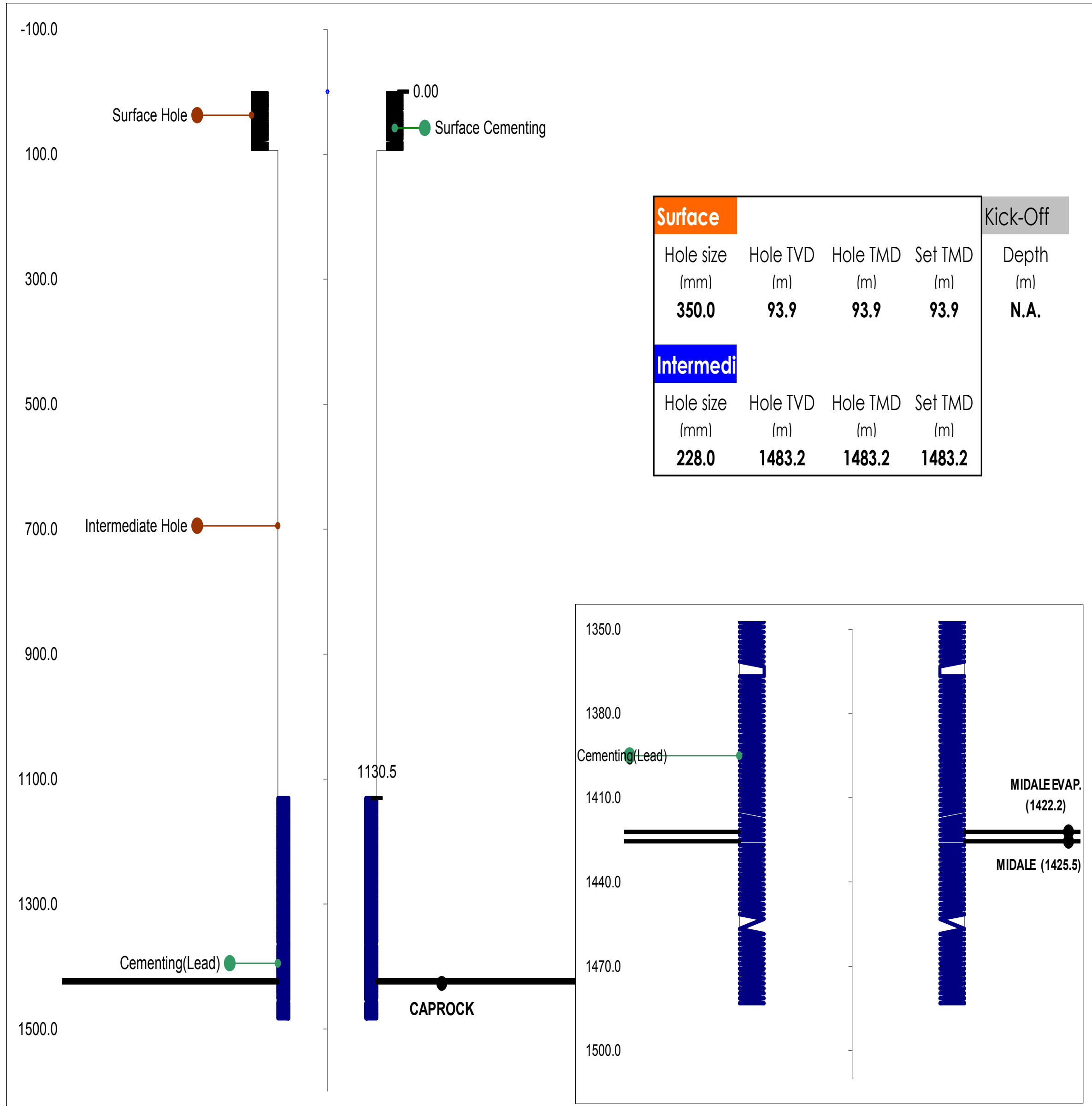
Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
177.80	**J-55**		153	

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
(PORTLAND)	**LEAD**	**200 SACKS**	**5.66**

H-40 Recorded in Wellfile
18.10 Computed from data in Wellfiel



Surface				Kick-Off
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Depth (m)
350.0	**93.9**	**93.9**	**93.9**	**N.A.**

Intermedi			
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)
228.0	**1483.2**	**1483.2**	**1483.2**

UWI 101140700613W200

Spud Date: 9/19/1957
Period: 1956-1967
Type: VCAL
Purpose OIL WELL (ABANDONED)

Horizontal Scale: 15

Surface Information

Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
273.00	**H-40**	124.10		

Cementing

Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD	**325 SACKS**	**9.20**

Intermediate Information

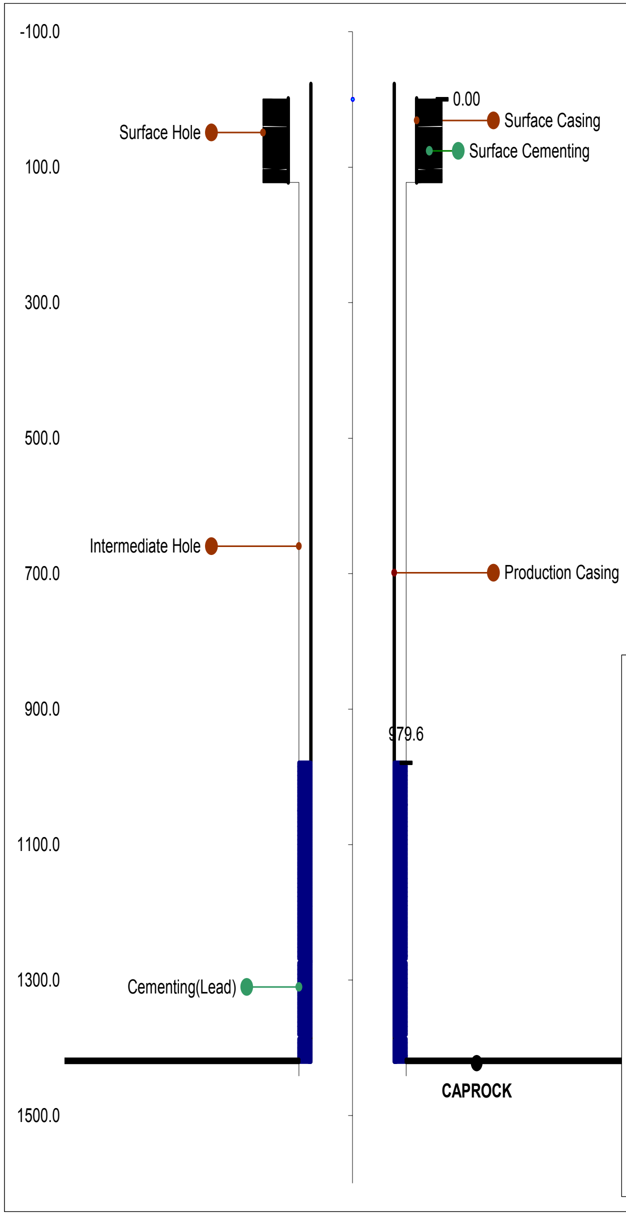
Casing

Size (mm)	Grade	Length (m)	JTS	Thickness (mm)
177.80	**J-55**	1443.10		

Cementing

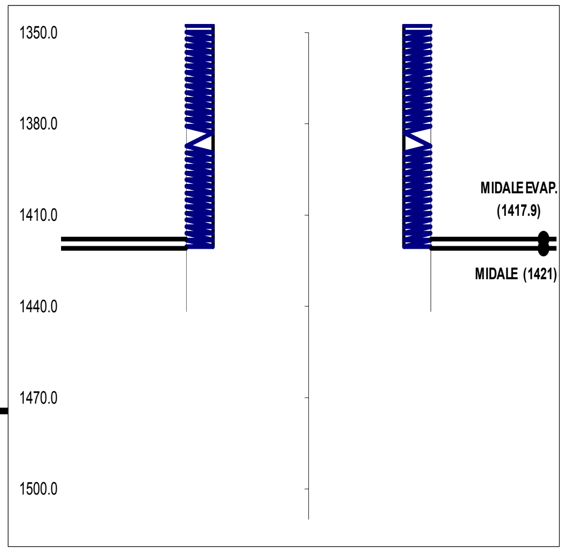
Description	Fluid Type	Cement Vol. (tonnes)	Slurry Vol. (m3)
	LEAD	**250 SACKS**	**7.08**

H-40 Recorded in Wellfile
18.10 Computed from data in Wellfiel



Surface				Kick-Off
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)	Depth (m)
381.0	**122.5**	**122.5**	**122.5**	**N.A.**

Intermedi			
Hole size (mm)	Hole TVD (m)	Hole TMD (m)	Set TMD (m)
228.0	**1441.7**	**1441.7**	**1420.4**



Mud removal (Weyburn)

Typical drilling – completion data (Wellbore drilled in 1950's)

MOBIL OIL OF CANADA, LTD.
Petroleum Engineering Department

DAILY WELL HISTORY

WELL: M.O. South Ralph X-14-18

FIELD: Weyburn

CASING: 10 ¾" landed at 301.00 C/A 200 sacks plus 2% Cacl2
5½" landed at 4777.12' C/A 350 cu ft. Rexlite plus 2% Gel

Elev. K.B. 1915'

Ran 148 joints, 5½", 15.5# S&L, T&C, Rge 2 J-55, 8 thd/in
Baker float shoe on bottom of first joint. Baker float collar
on top of first joint. Ran 4 B&W latch on centralizers, one
in middle of shoe joint and one on collars 2,3 & 4.
30 B&W rotating scratchers, 5 per joint on joints, 2,3,4,6,5
and 7. Casing landed at 4777.12' K.B. Cemented with 350 cu
ft. Rexlite cement. Plug down at 7:35 AM with 1200 psi.
Casing landed using Cameron CA slips in a Cameron casing
bowl. Ran tubing to water from casing with oil.
Ran 151 joints of 2 7/8" EUE tubing, 6.5#, J-55, Rge 2, 8thd/in

on top of first joint. Ran 4 B&W latch on centralizers, one
in middle of shoe joint and one on collars 2,3 & 4.
[redacted]
Plug down at 7:35 AM with 1200 psi.
Casing landed using Cameron CA slips in a Cameron casing
bowl. Ran tubing to water from casing with oil.
Ran 151 joints of 2 7/8" EUE tubing, 6.5#, J-55, Rge 2, 8thd/in

Drilling, Completion,… Reports and Wellfile Information

Saskatchewan Energy and Mines
Sedimentary Geodata

1914 Hamilton Street
Regina, Canada
S4P 4V4
Telephone (306)787-2550

Please Note: Horizontal wells require separate forms submitted for each leg.
Submit 4 copies to Geodata Division within 1 month of Finished Drilling Date.

Finished Drilling Report

93 F 44

WELL IDENTIFICATION OFFICIAL WELL NAME PCP ET AL WEYBURN UNIT 09-11-6-14 W2

	SS	LOC. X	LSD	SEC	TWP	RGE.	M	W/X	S	T	R
Surface location	1		9	11	06	14	W2	0			
Bottom Location	1	3/	9	11	06	14	W2	0			

If Horizontal Well: Leg #

K.B. Elev. 535.35 m Grd. Elev. 531.65 m Spud Date (YR MO DA) 93 06 09 Finished Drilling Date (YR MO DA) 93 06 14 Rig Released (YR MO DA) 93 06 15 Contractor: SIMMONS DRILLING

T.D. (Driller) 1447 m (Log) 1446 m P.B.T.D. 1442.3 m If Applicable: T.V.D. m Kick Off Point m Packer Depth m

ECONOMIC OBJECTIVE	WELL TYPE		PRESENT STATUS
☐ Stratigraphic	☒ Single ☐ Dual	☐ Hztl ☐ Multi	☐ Junked & Abandoned
☐ Oil	☐ Producer	☐ Gas Injection	☐ Dry & Abandoned
☐ Gas	☐ Water Injection	☐ Steam Injection	☒ Completed & Operating
☒ Service	☒ Water Source	☐ Combustion (Fire Flood)	☐ Standing Perforated
☐ Potash	☐ Water Disposal	☐ Observation	☐ Standing Cased
☐ Other (specify below)	☐ Gas Storage	☐ Test	☐ Drilling Suspended
	☐ Solutioning	☐ Other (specify below)	☐ Other (specify below)

HOLE Size	HOLE Depth	CASING Size	CASING Depth Set	Mass per unit length	Grade	Cement & Additives
311	156.5	219.1	56.5	35.7	J55	14t 010 G + 3% CaCl2
200	1447	139.7	1445.73	20.5	J55	LEAD 16.3t 0M G + 0.5% CFR-3
						TAIL 4t 010 G + 0.75% HALAD 322

WELL LOGS AND/OR SURVEYS TAKEN

Type of survey	Interval from	to
GR - CAL	1445	150
CMP. NEUTRON LITHO DENSITY	1445	1300
DUAL IND. SFL	1443	156.5

COMPLETION DETAILS - Please include liner intervals

Perforation Date YR	MO	DA	Perforated interval from	to	Formation	Shots /m	Type and size	Treatment date YR	MO	DA	Treatment (acidizing, fracturing, cement squeeze or plug back of perforations. If no treatment state "NONE")
93	08	13	1422.5	1424.5	MARLY	13	23g D.P.	93	08	14	STRESS FRAC ON MARLY PERFS
			1425.5	1427.5	MARLY	13	23g D.P.	93	08	16	ACIDIZE PERFS WITH 1000 l OF 25% HCl
			1429.0	1436.0	VUGGY	13	23g D.P.				ACID SQUEEZE FROM TOP DOWN IN 11·1m STAGES
											AVG. RATE 0.26 m³/m @ 2MPa

CORE AND SAMPLES FORWARDED TO:
S.E.M. Subsurface Geological Laboratory
Other (specify below)

CORE DETAILS Type: Wire-line	Dia-mond	Side-wall	Interval from	to	Recovered percent	Analyzed Yes	No

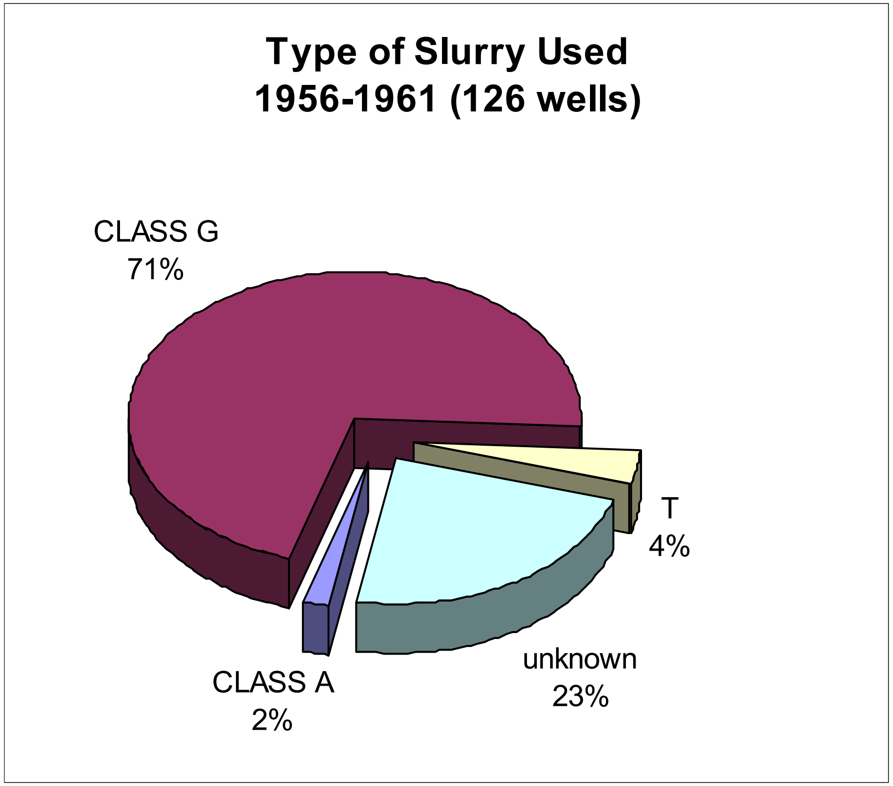
ADDITIONAL DATA - This space may be used for additional details or remarks.

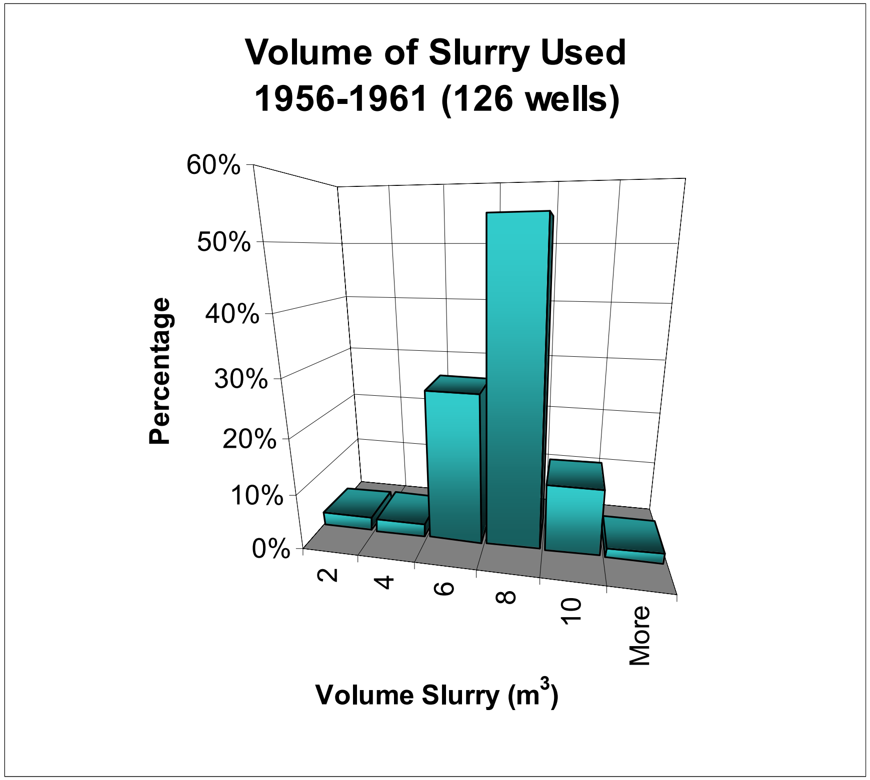
FOR DEPARTMENT USE ONLY
WELL CONFIDENTIAL UNTIL DATE SHOWN

93/07/13

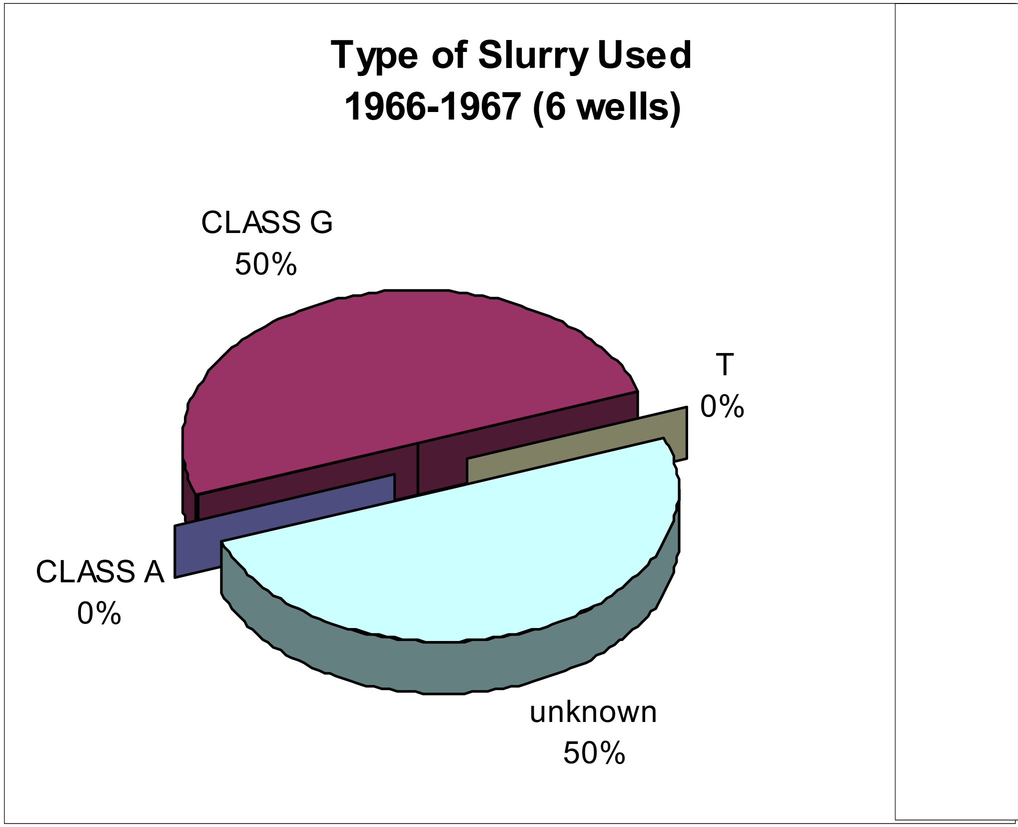
I-1 (revised Feb/93)

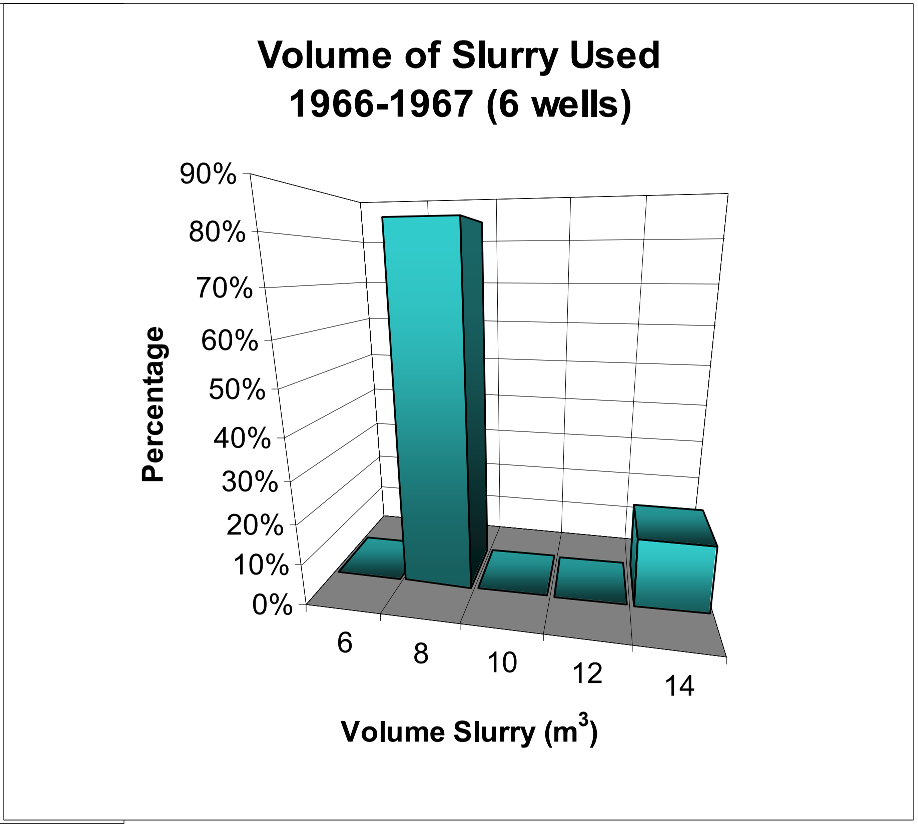
1956-1961 Wells



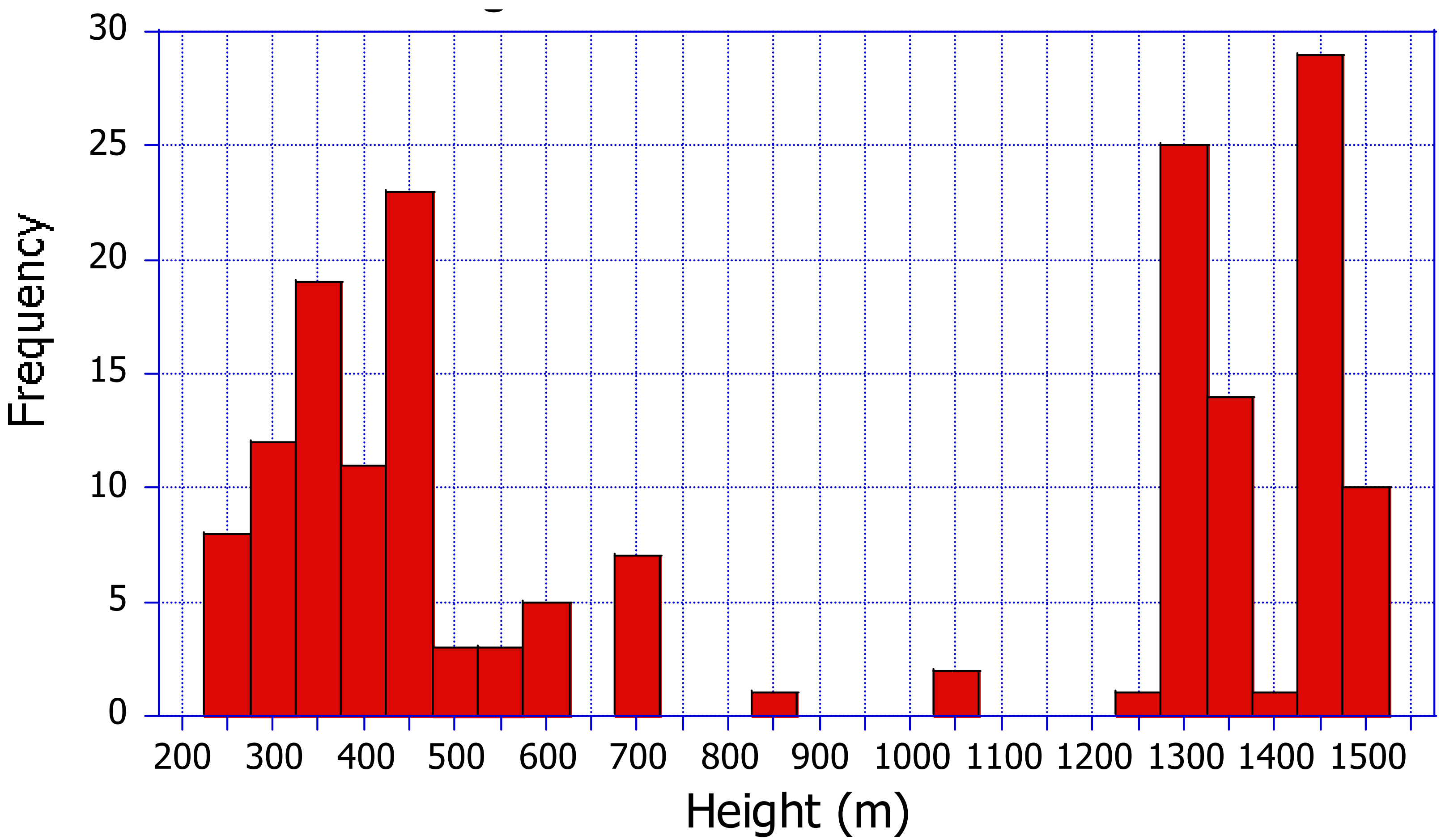


1966-1967 Wells

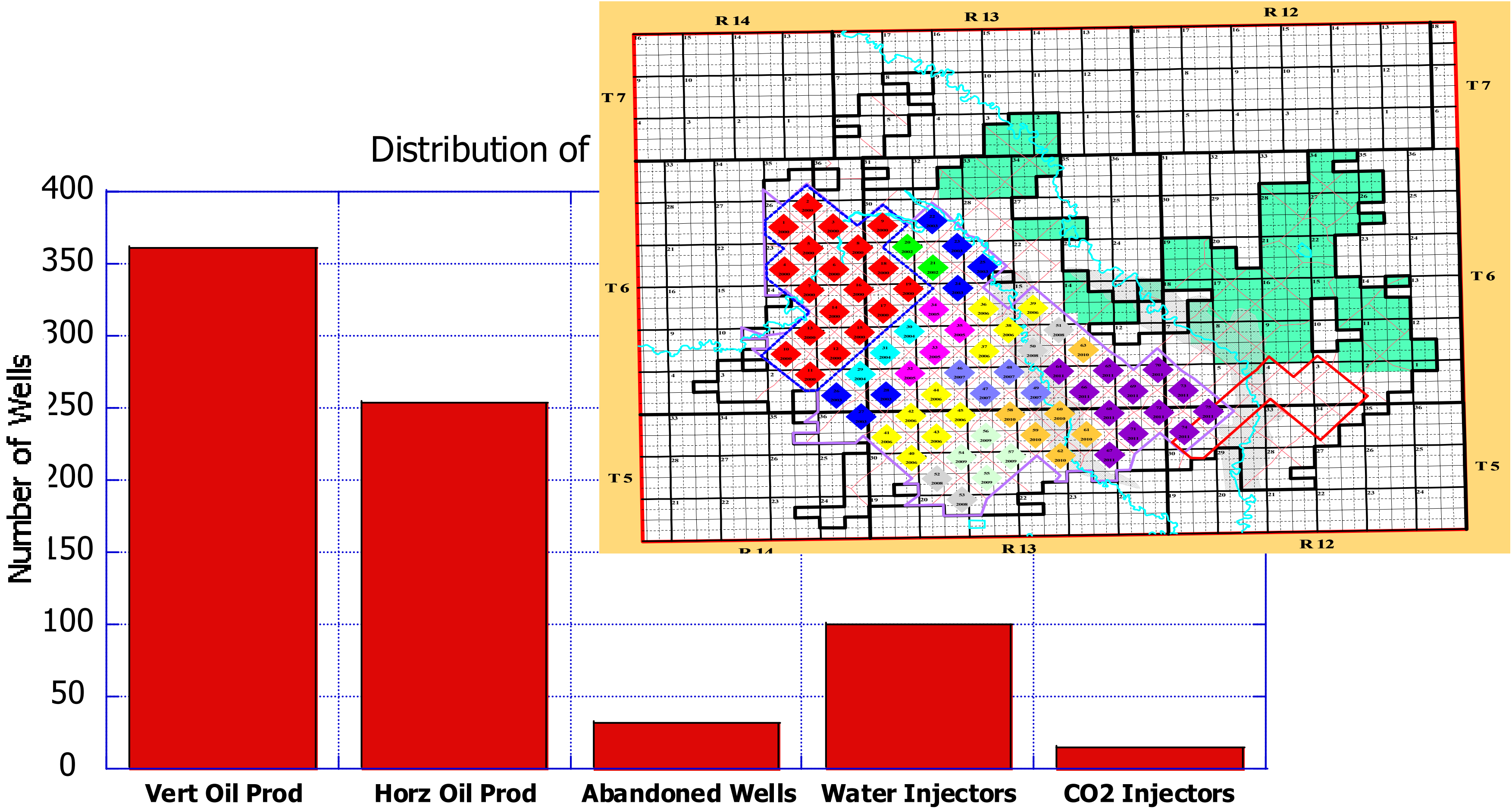




Height of Annular Cement Column



75 Pattern Well Distributions (for June PCSM)



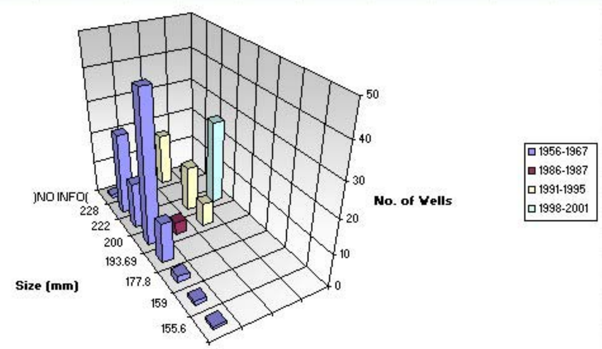
More Statistics….

Microsoft Excel - STATISTICS(ALL-WELLS)

HOLE SIZE-HISTOGRAM

LEG No.	(Multiple Items)
STAGE	INTERMEDIATE
WELL TYPE	(Multiple Items)

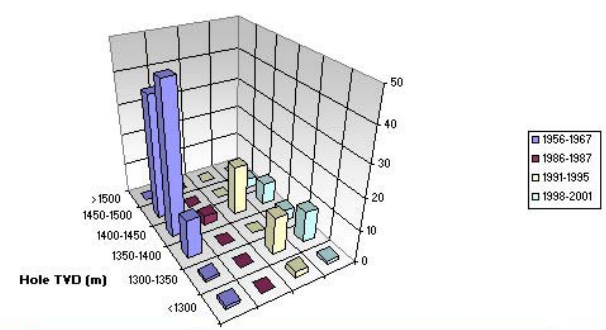
Count of HOLE SIZE	PERIOD			
HOLE SIZE	1956-1967	1986-1987	1991-1995	1998-2001
155.6	1			
159	1			
177.8	2			
193.69	12			
200	45	4	7	
222	14		14	26
228	25			
(NO INFO)	1	2	16	1
	101	6	37	27



HOLE TVD-HISTOGRAM

LEG No.	(Multiple Items)
STAGE	INTERMEDIATE
WELL TYPE	(Multiple Items)

Count of HOLE TVD	PERIOD			
HOLE TVD	1956-1967	1986-1987	1991-1995	1998-2001
<1300	1		2	1
1300-1350	1		12	10
1350-1400	12			4
1400-1450	47	3	16	7
1450-1500	39			3
>1500				
	100	3	30	25



STAT(BOREHOLE) STAT(CASING) STAT(ACCESORIES) STAT(CEMENTING) BASE(CAS-ACC-CEM

CANA

Sheet ___ of ___

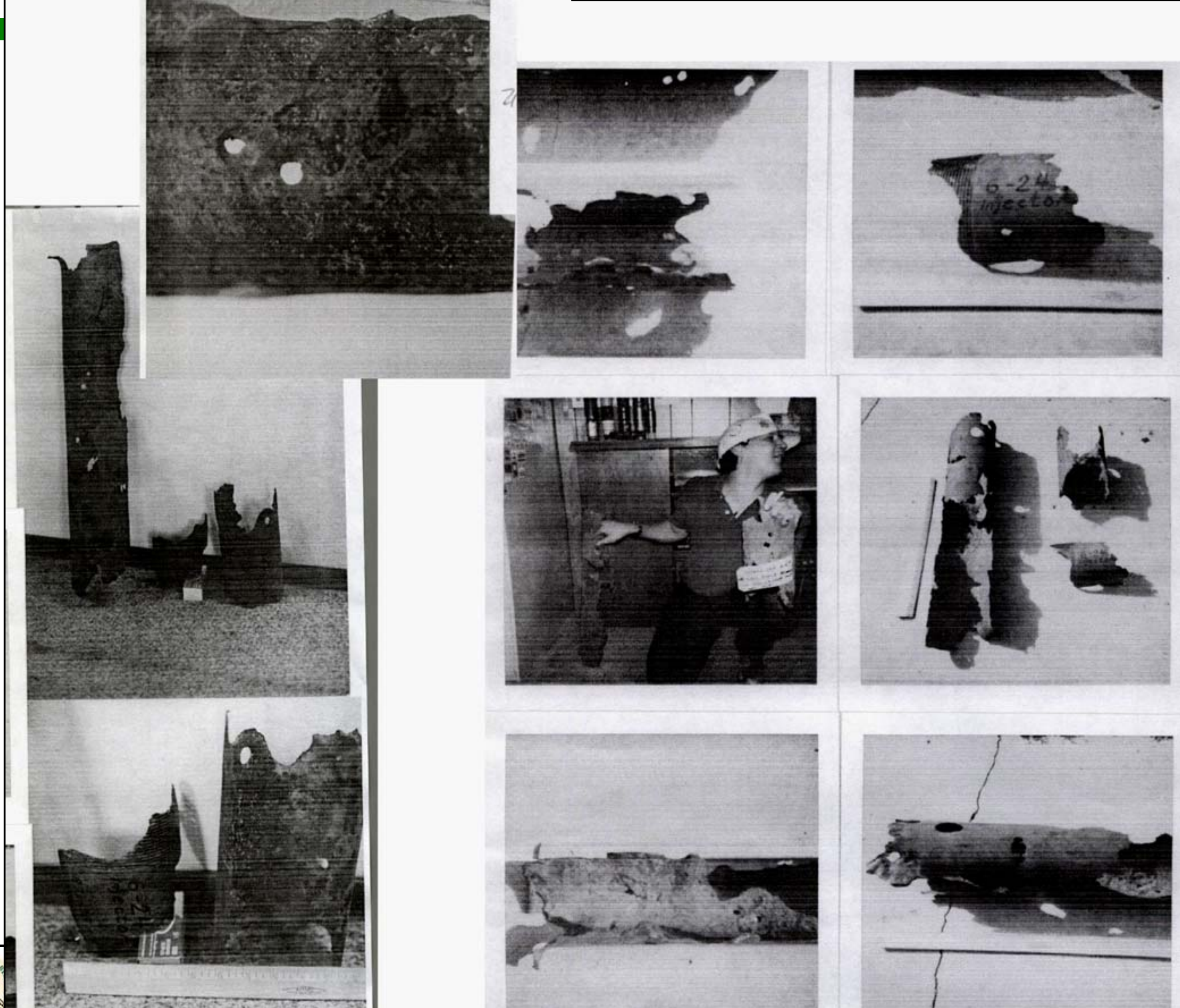
Date July 30, 2002

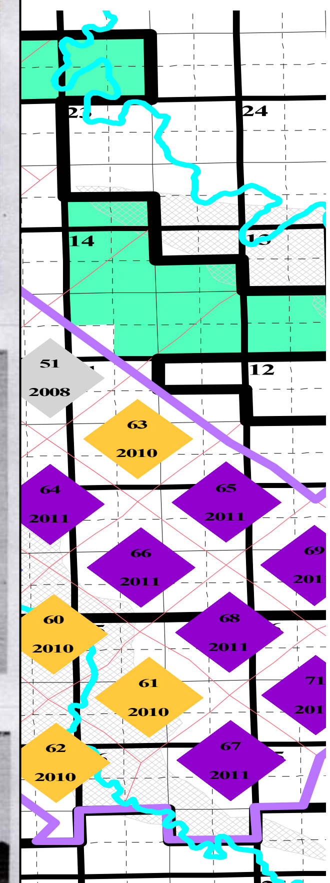
CASING During Injector Clean Out

By 101/06-24-006-14W2

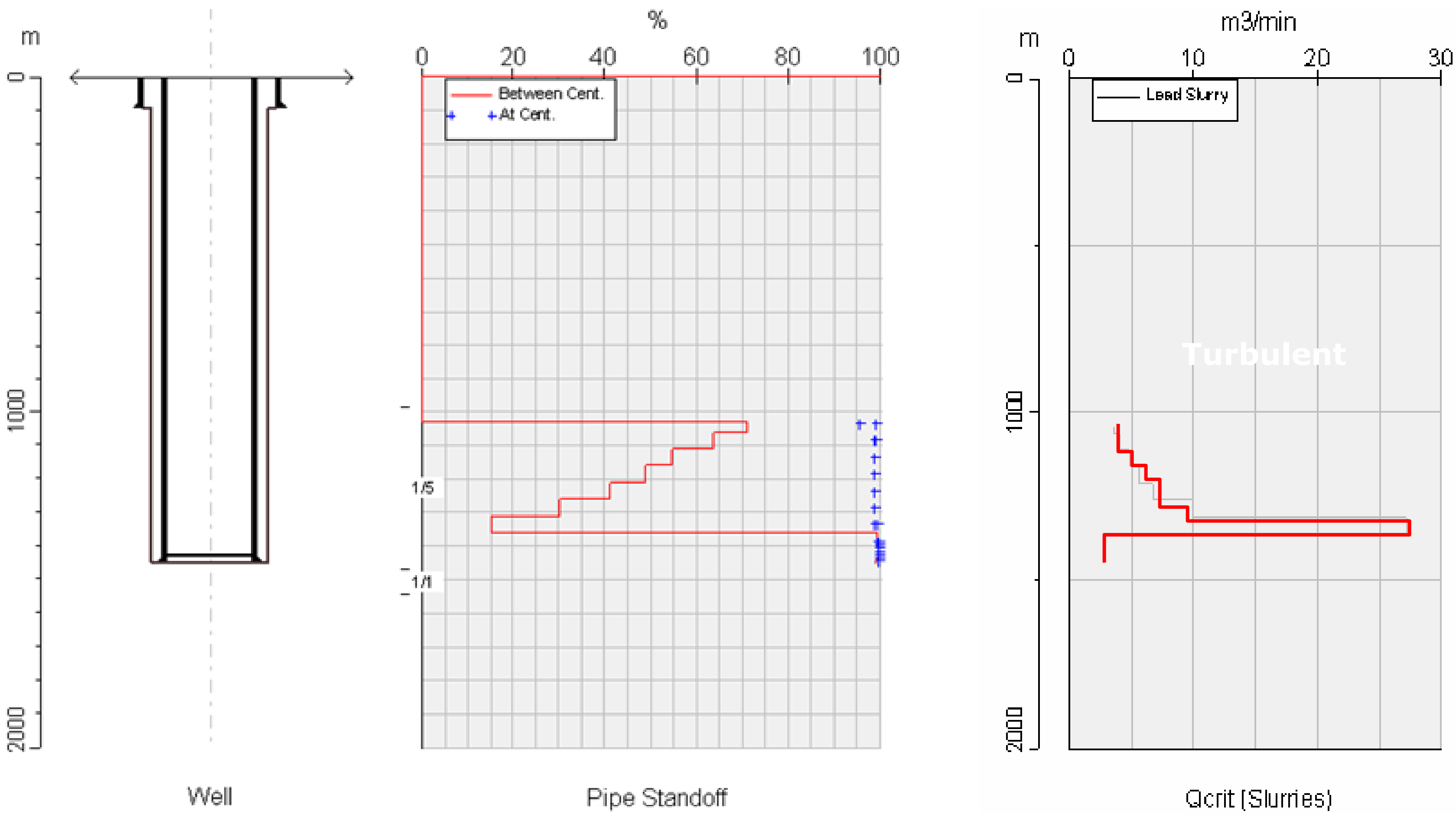
or IPMP Project 1987/08/15

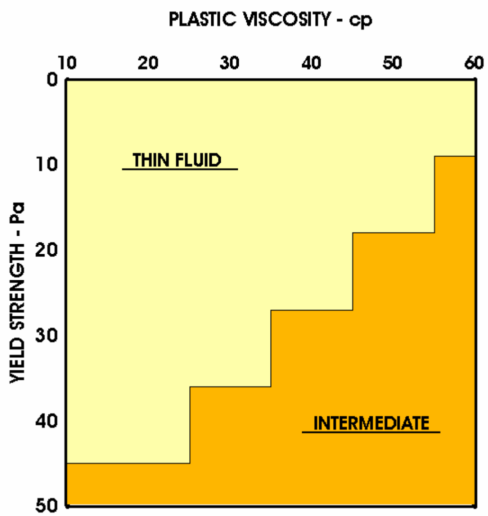
Water Injector.



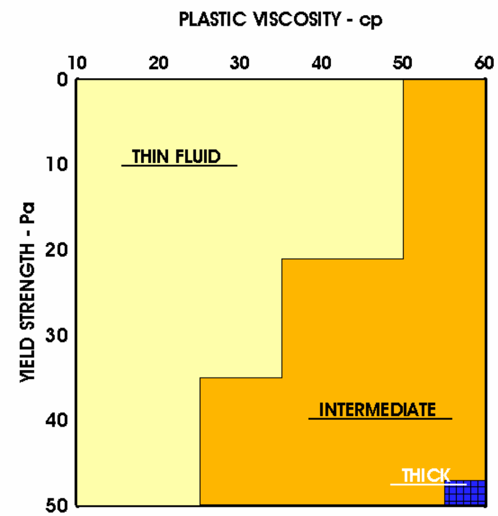


Mud removal (Weyburn)

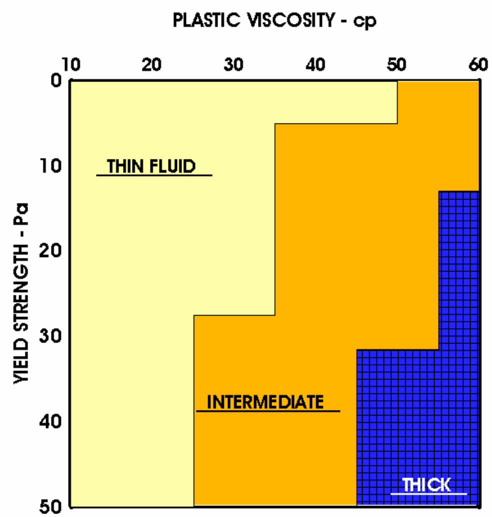




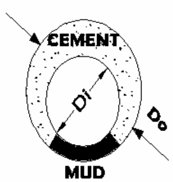
STO 75%



STO 50%

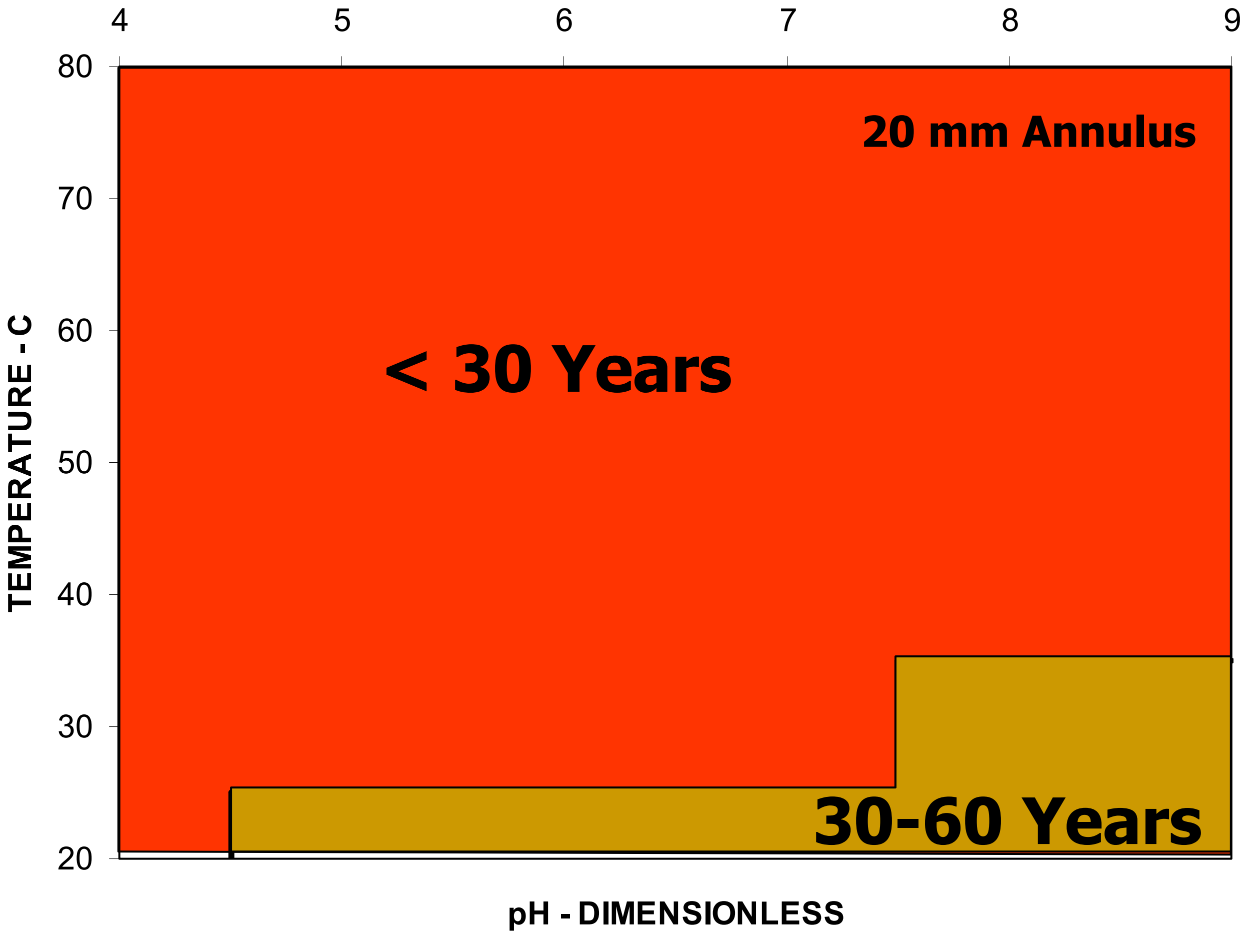


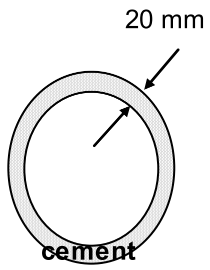
STO 33%



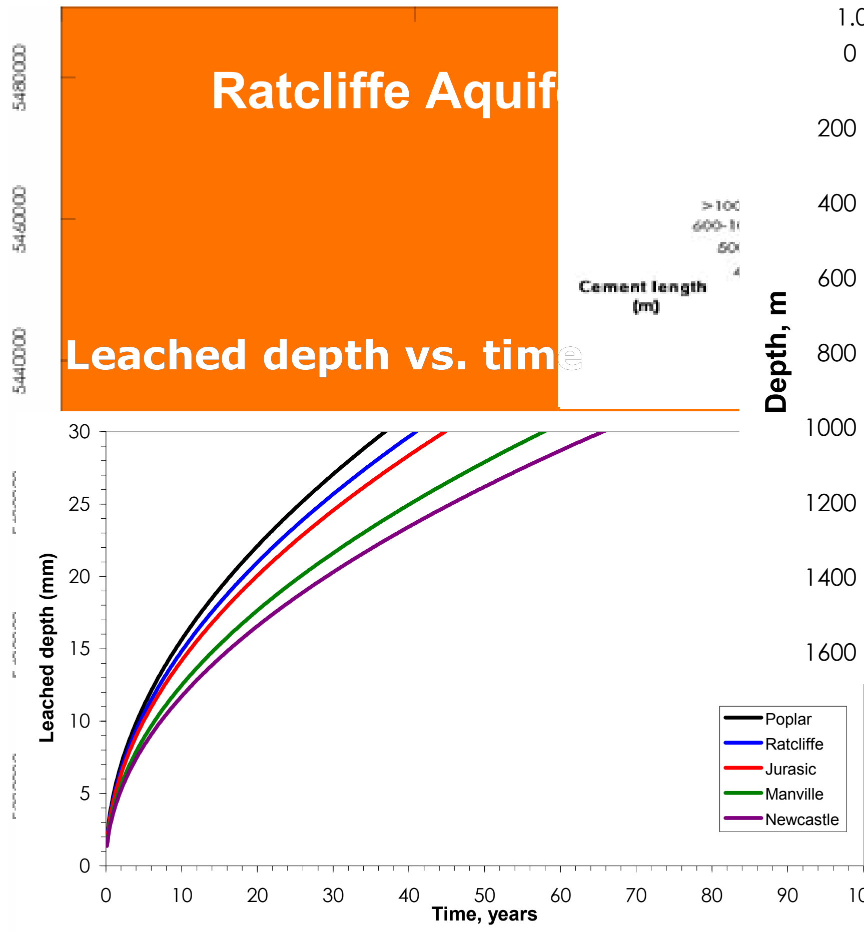
(Do-Di)
50mm

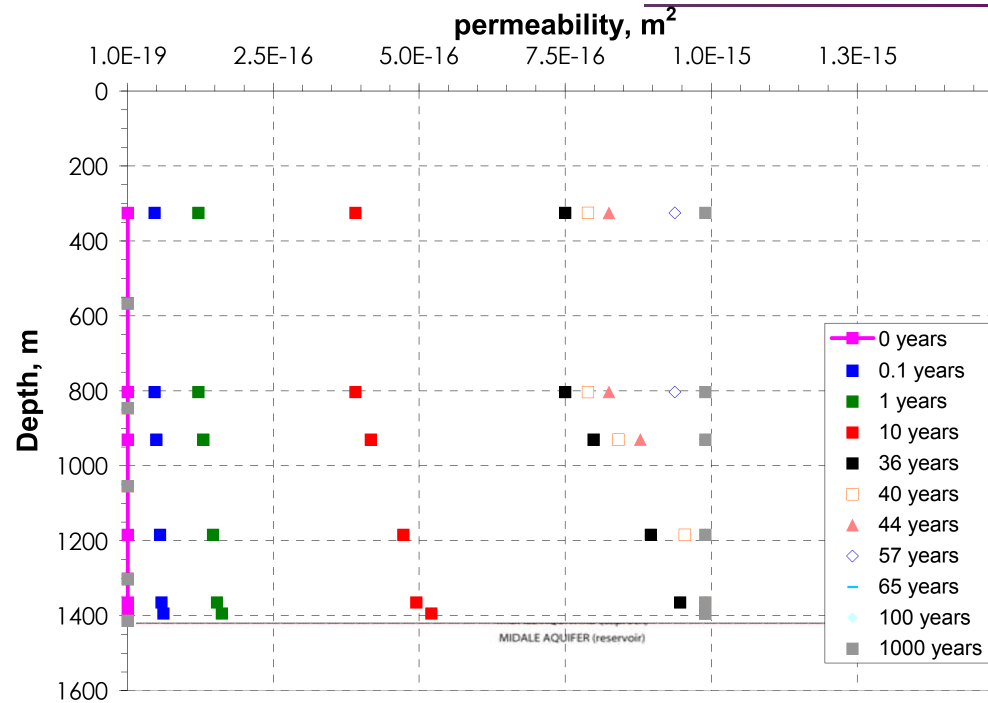
Cement Degradation – Acid Attack Class G Cement - Analytical

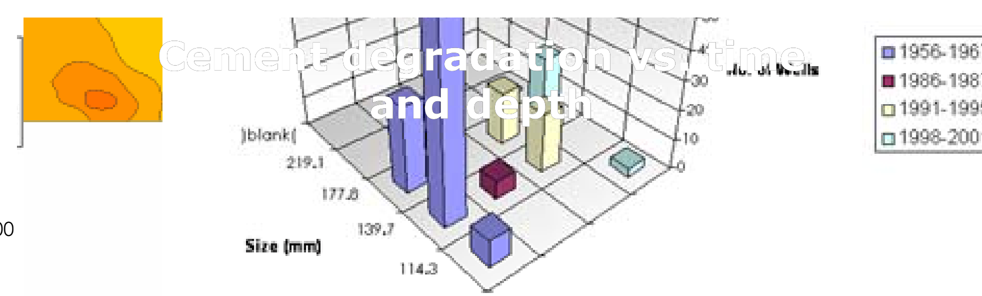




Acid Attack Mechanisms (Weyburn)



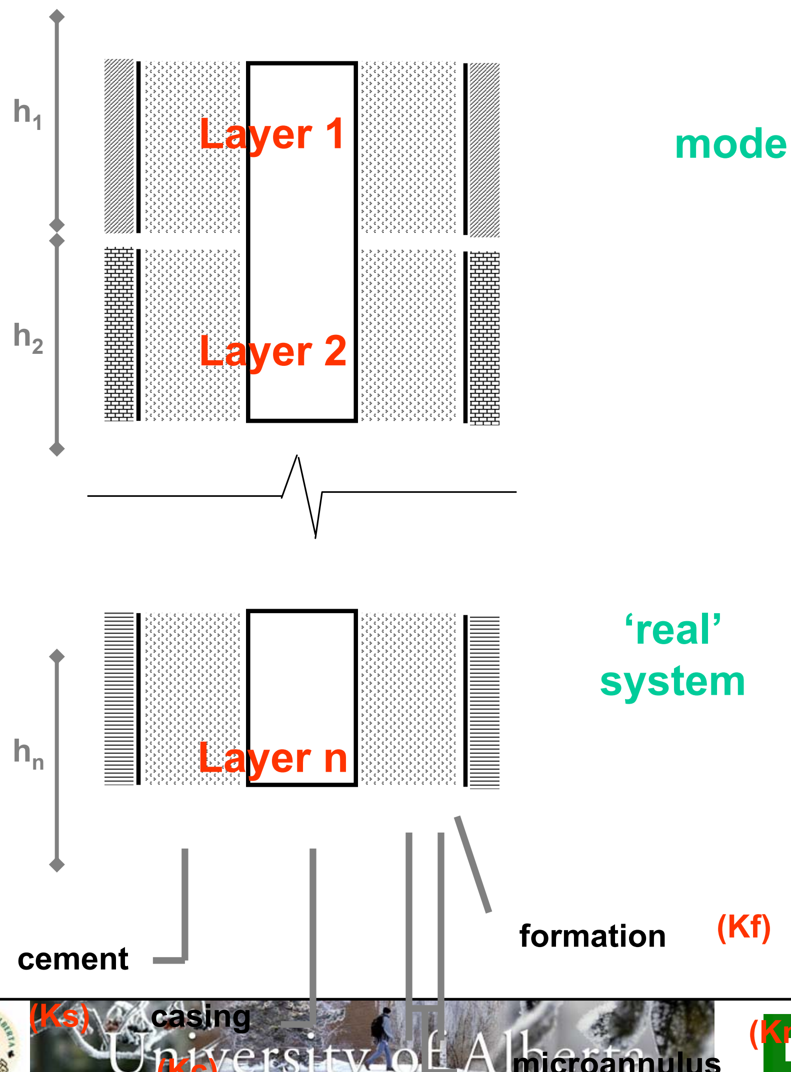


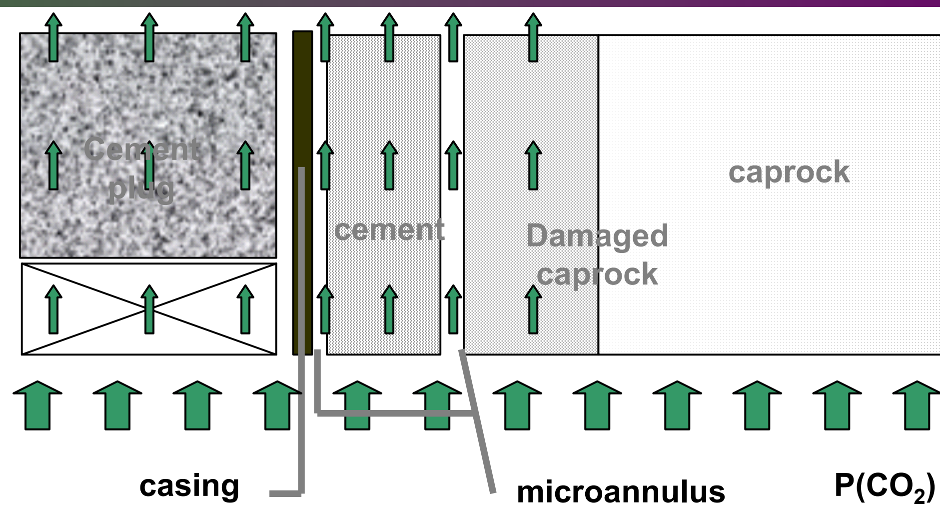


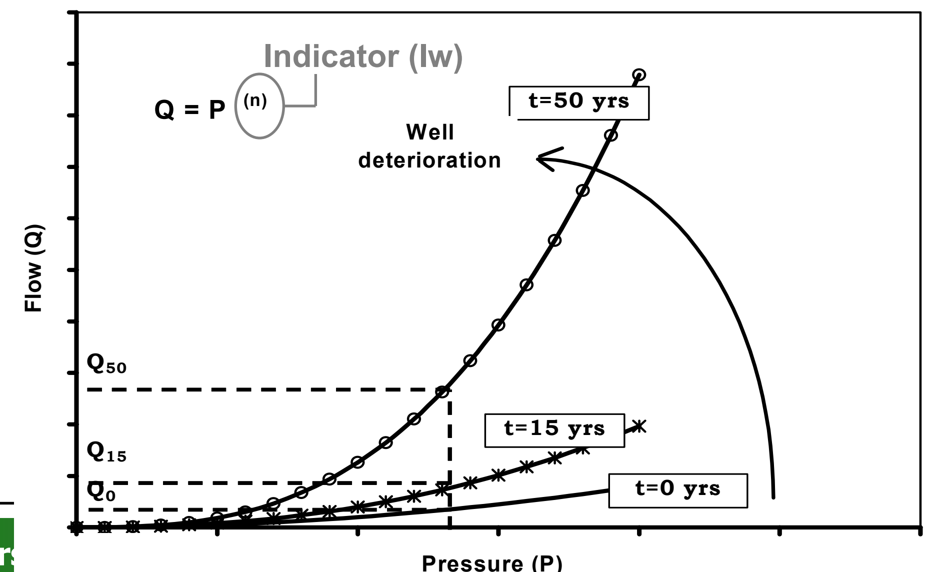
Casing diameter histogram

Wellbore diameter histogram

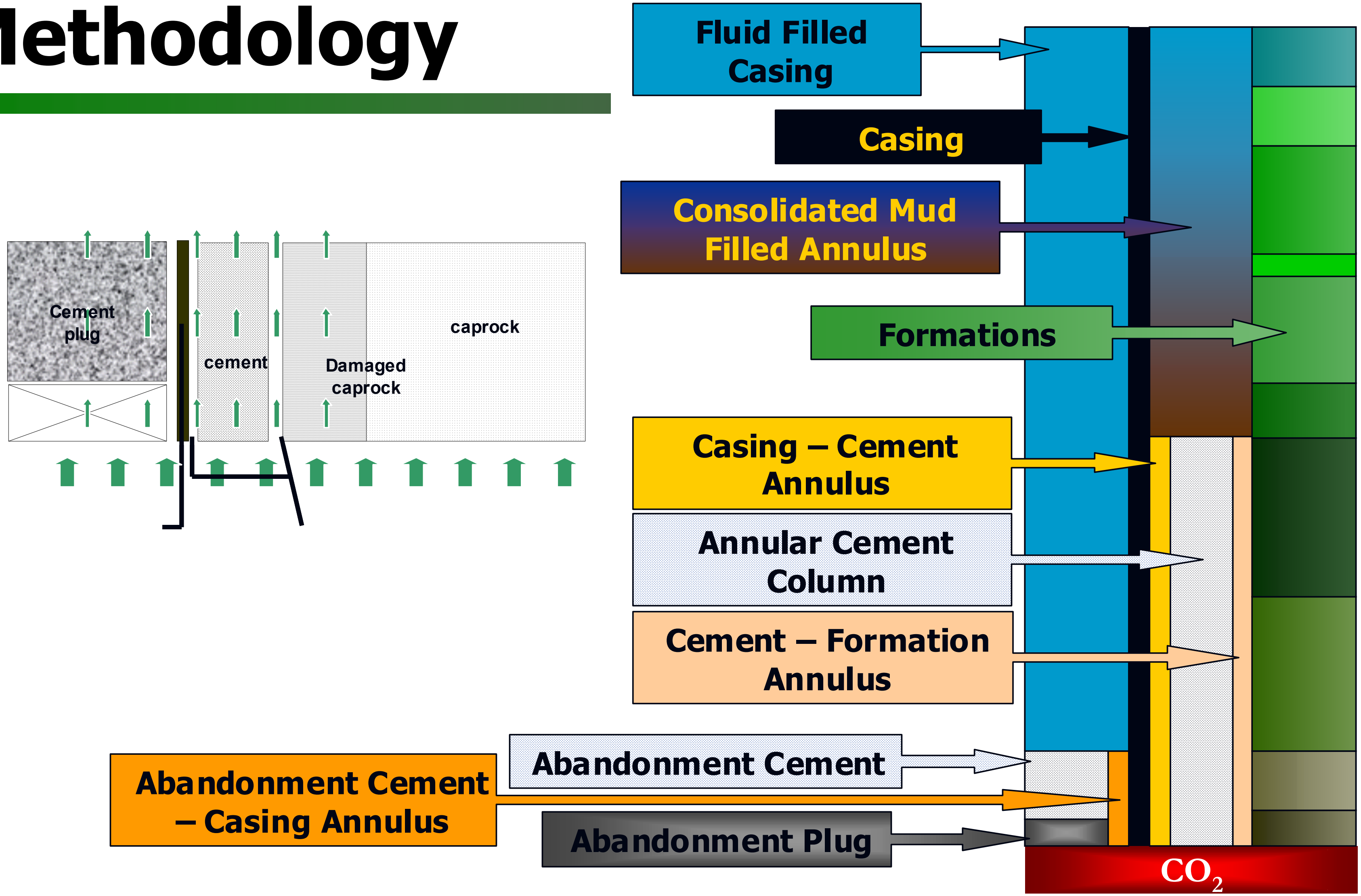
Process modelling CO_2 flow in wells







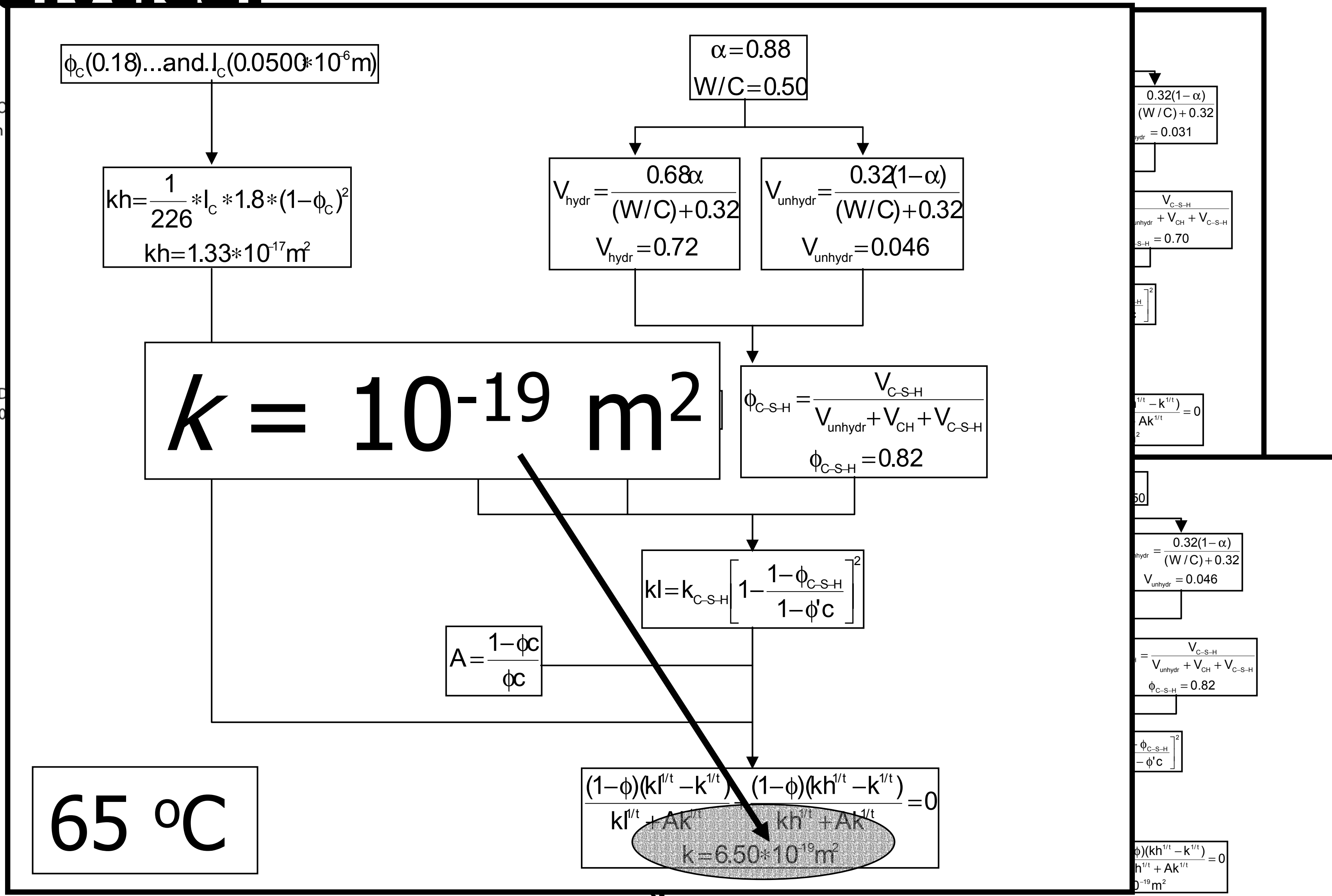
Well Integrity Assessment Methodology



Cement Transport Properties - Analytical

SURFACE HO
Φ 350 mm

INTERMED
Φ 200

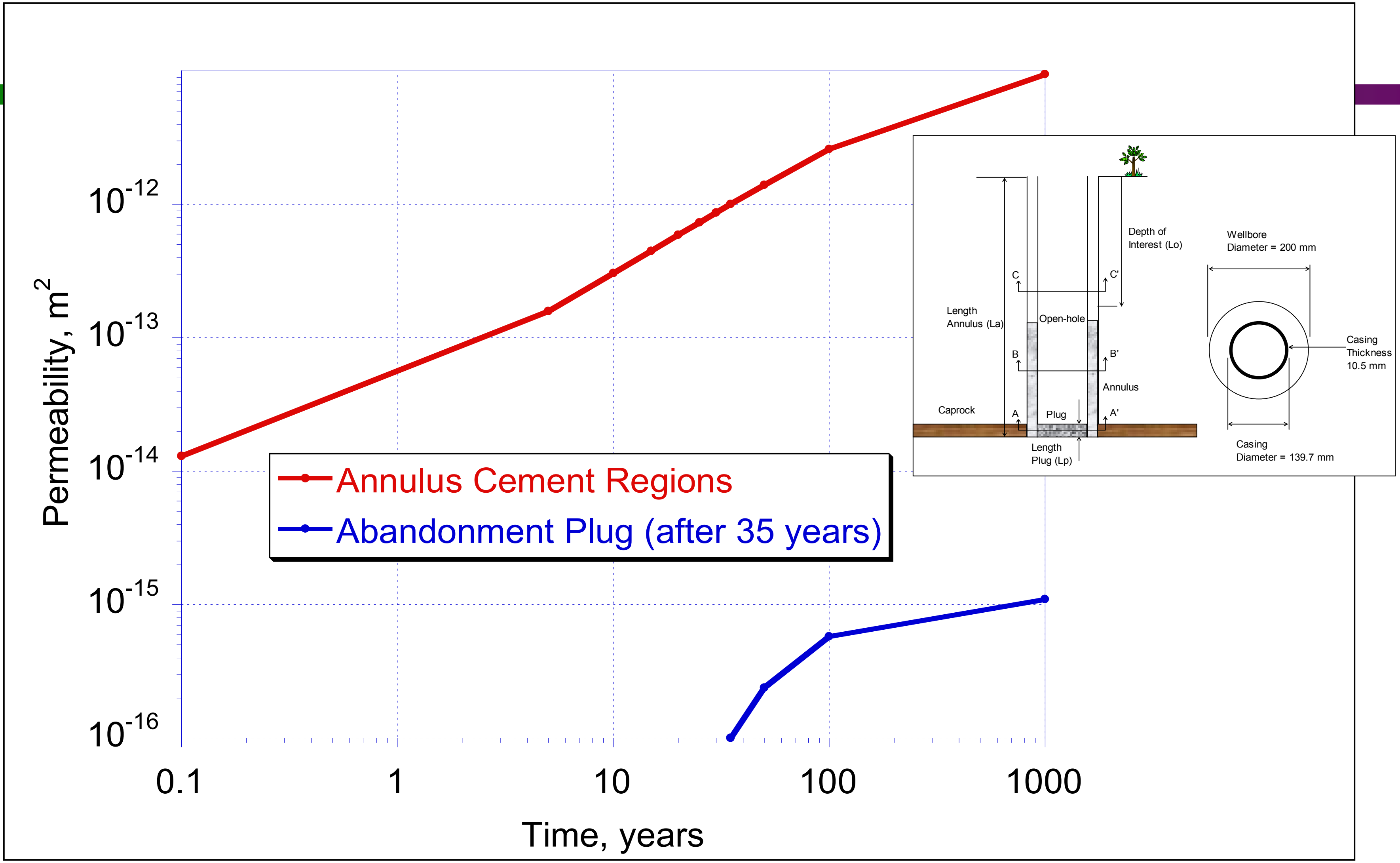


Abandoned Wells – (1956-1967) Plug & annulus cement degrade similarly.
Permeability at 2000: **10^{-14}** m^2.
Permeability at 2100: **10^{-13}** m^2. Aging, mechanical, temp. effects are not large. Meanly leaching.
Permeability at 3000: **10^{-11}** m^2. Degradation to amorphous silica.

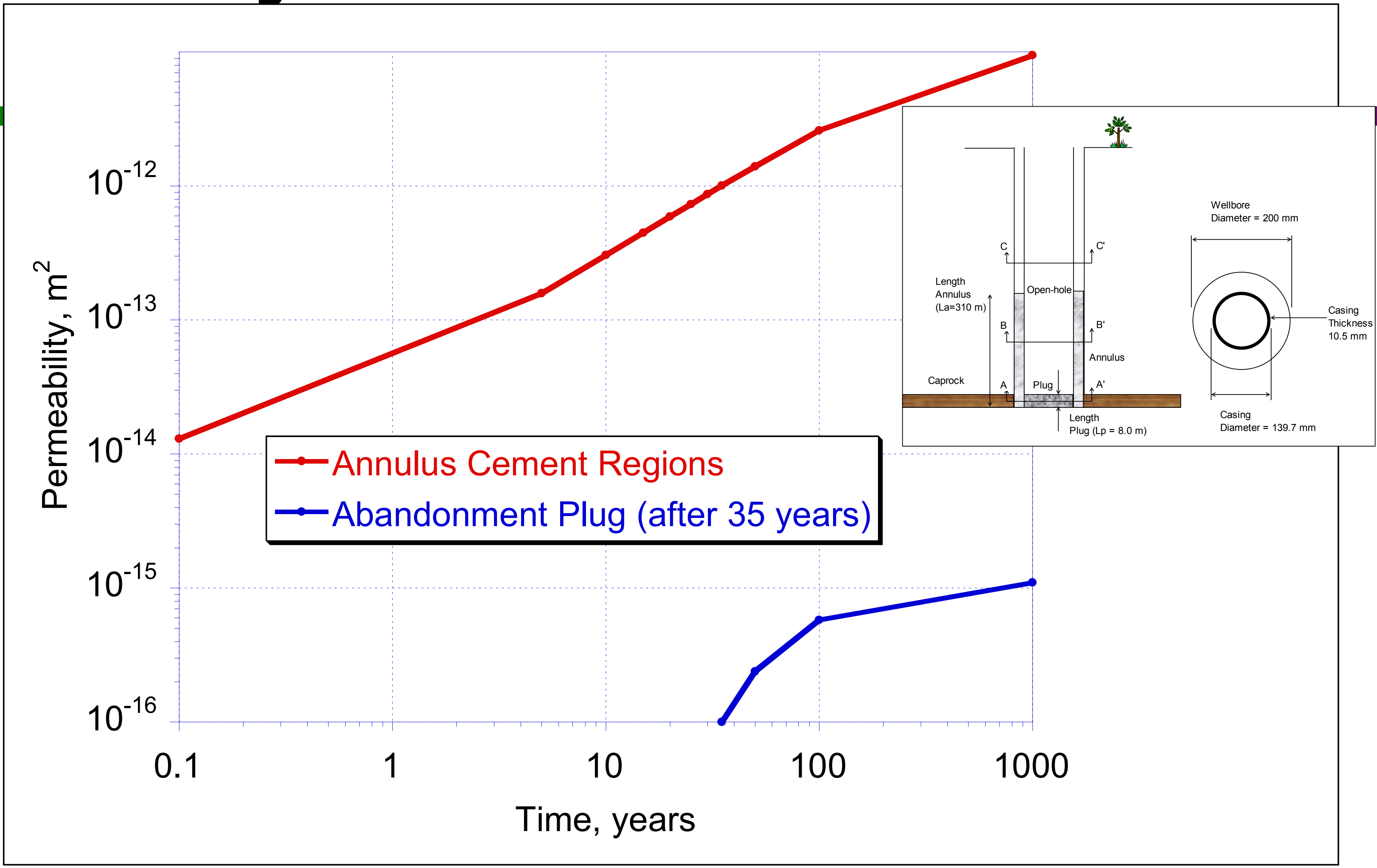
Oil Wells, Water Injectors & WAG Injectors
(1956-1967) Plug & annulus cement degrade independently
Annulus
Permeability at 2000: **10^{-14}** m^2.
Permeability at 2035: **10^{-12}** m^2. Mechanical & thermal effects, although (leaching) important.
Permeability at 3000: **10^{-11}** m^2. Degradation to amorphous silica.
Plug: Installed 2035, length 8 m, state of the art
Permeability at 2035: **10^{-16}** m^2.
Permeability at 3000: **10^{-15}** m^2. Chemical degradation (aging). Better cement quality and only the bottom is exposed.

CO_2 Injectors and Producers - Age: 1998-2001) Plug & annulus cement degrade independently
Annulus
Permeability at 2000: **10^{-17} m^2**.
Permeability at 2035: **10^{-15} m^2**. Mechanical & thermal effects, although (leaching) important.
Permeability at 3000: **10^{-12} m^2**. (Affected during operational life of well)
Plug: Installed 2035, length 8 m, state of the art
Permeability at 2035: **10^{-16} m^2**.
Permeability at 3000: **10^{-15} m^2**. Chemical degradation (aging). Better cement quality and only the bottom is exposed.

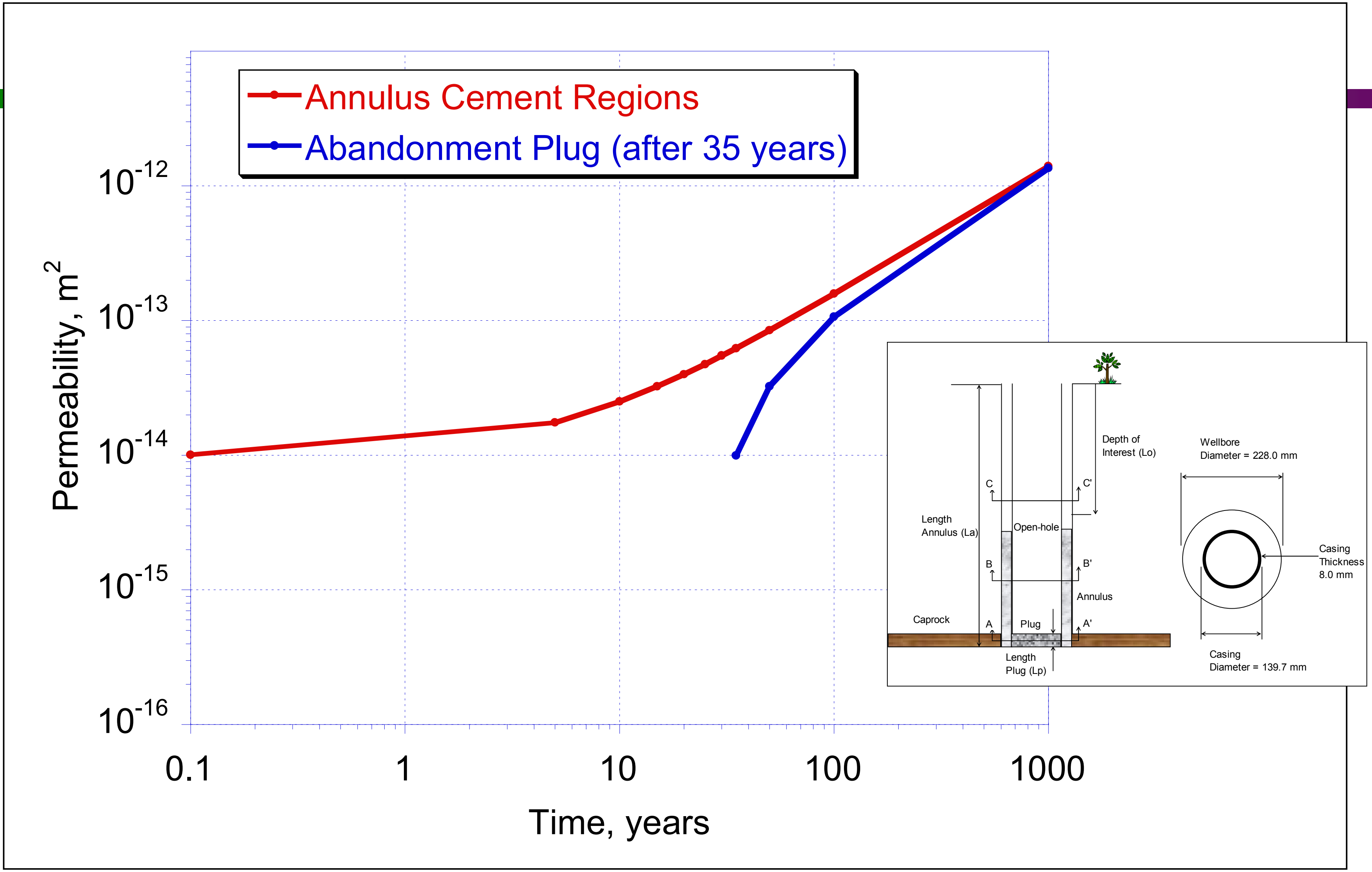
Oil & Water Injection Wells



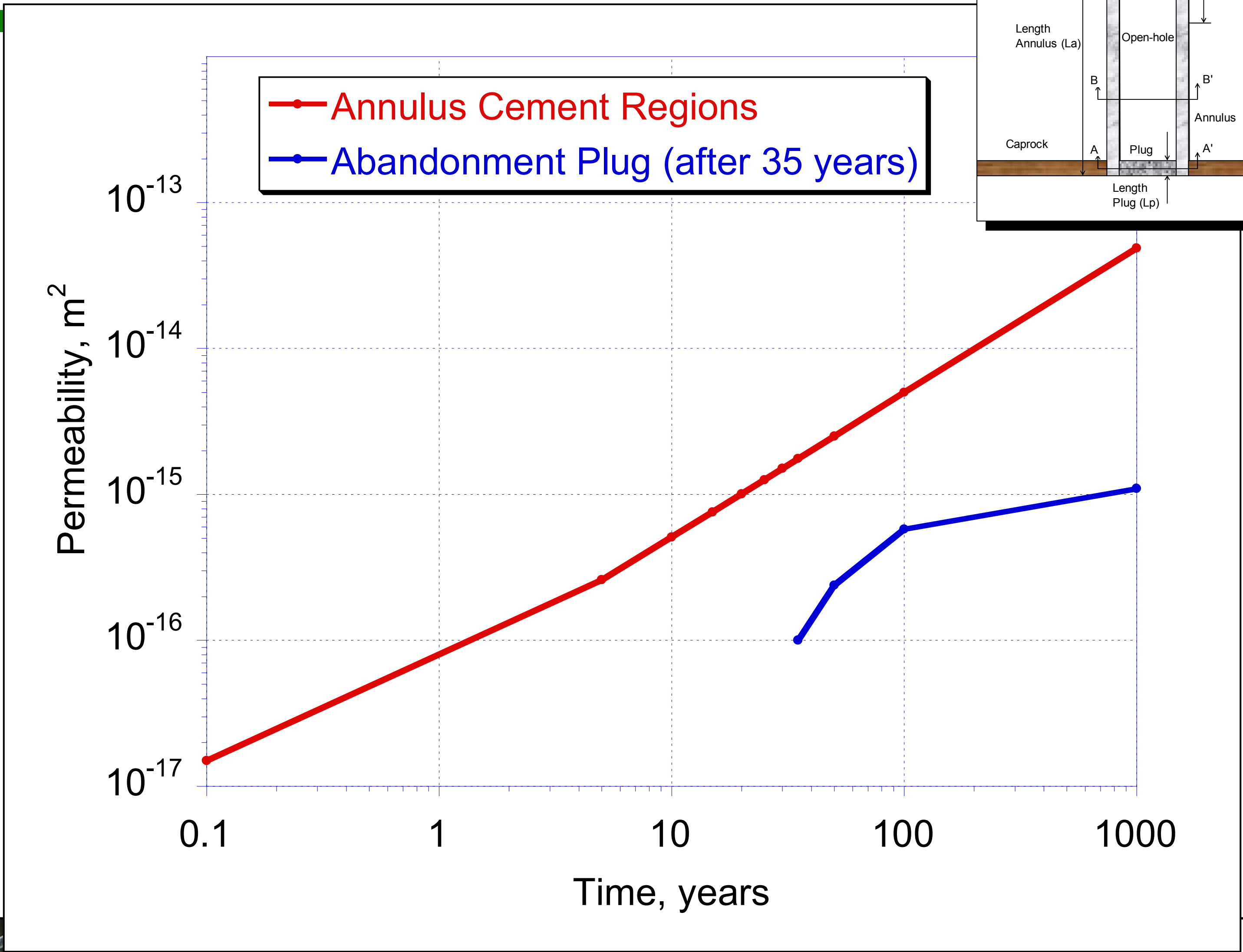
WAG Injection Wells



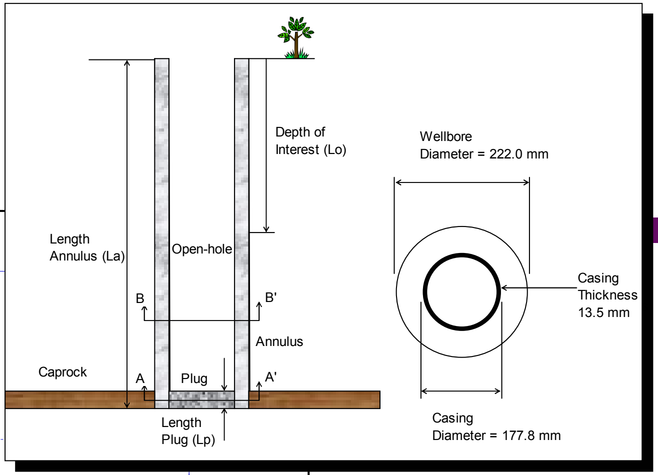
Abandoned Wells



CO_2 Wells

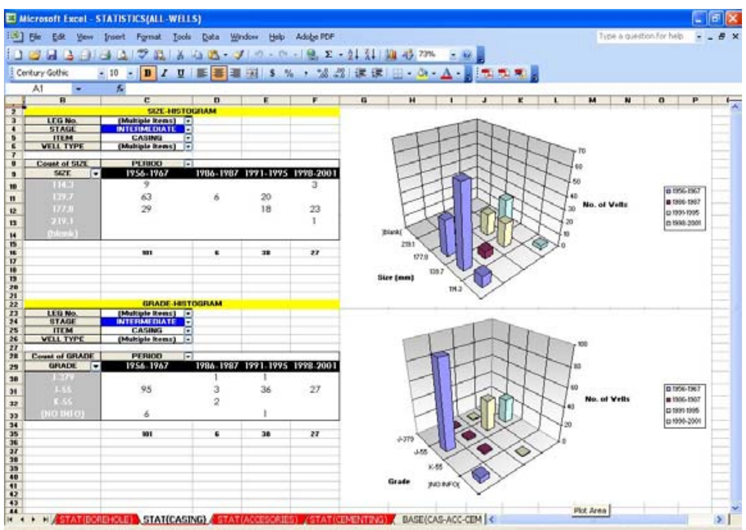


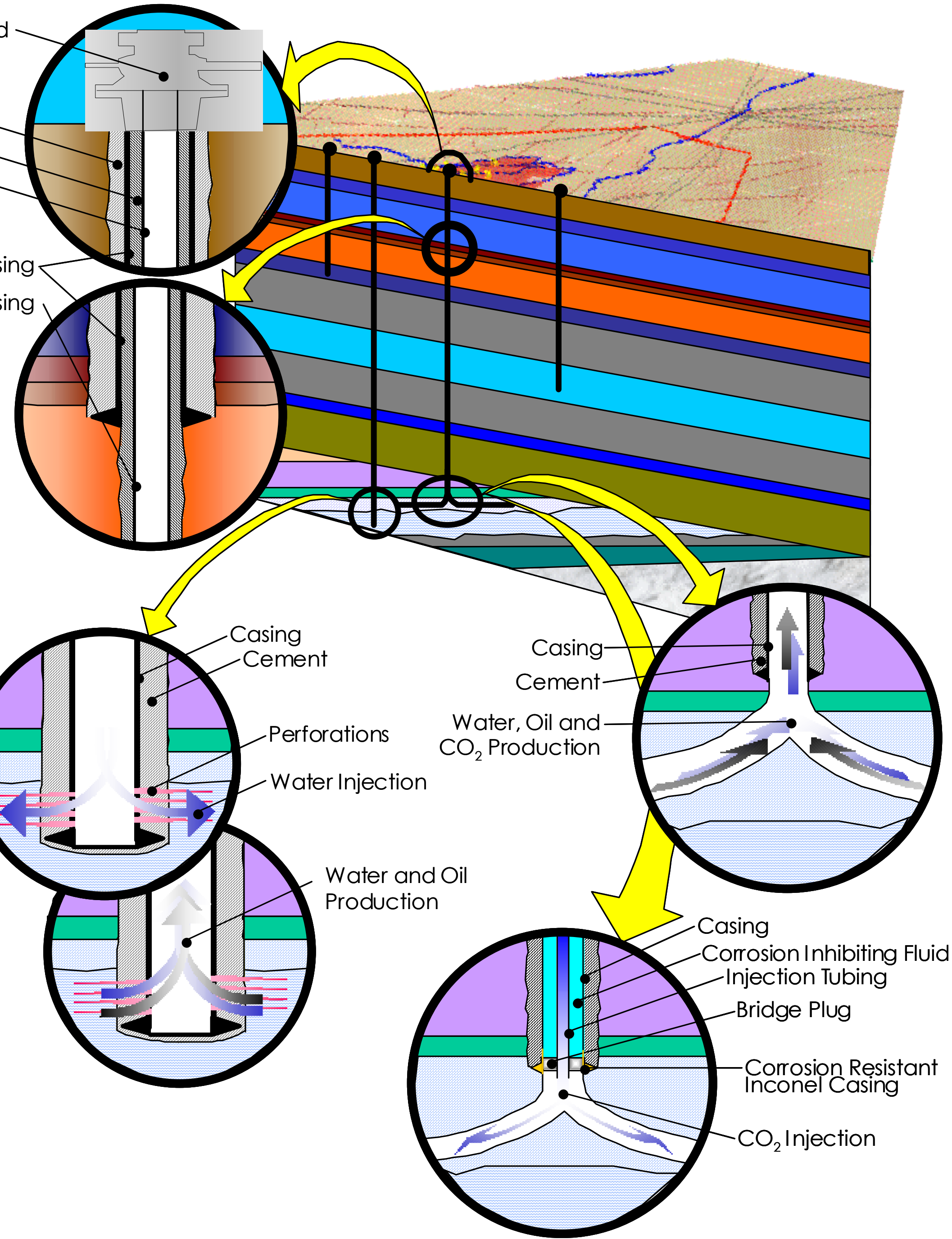
Annulus Cement Regions
Abandonment Plug (after 35 years)
Permeability, m2
10-13
10-14
10-15
10-16
10-17
0.1
1
10
100
1000
Time, years



Depth of Interest (Lo)
Wellbore Diameter = 222.0 mm
Length Annulus (La)
Open-hole
B
B'
Annulus
Casing Thickness 13.5 mm
Caprock
A
Plug
A'
Length Plug (Lp)
Casing Diameter = 177.8 mm

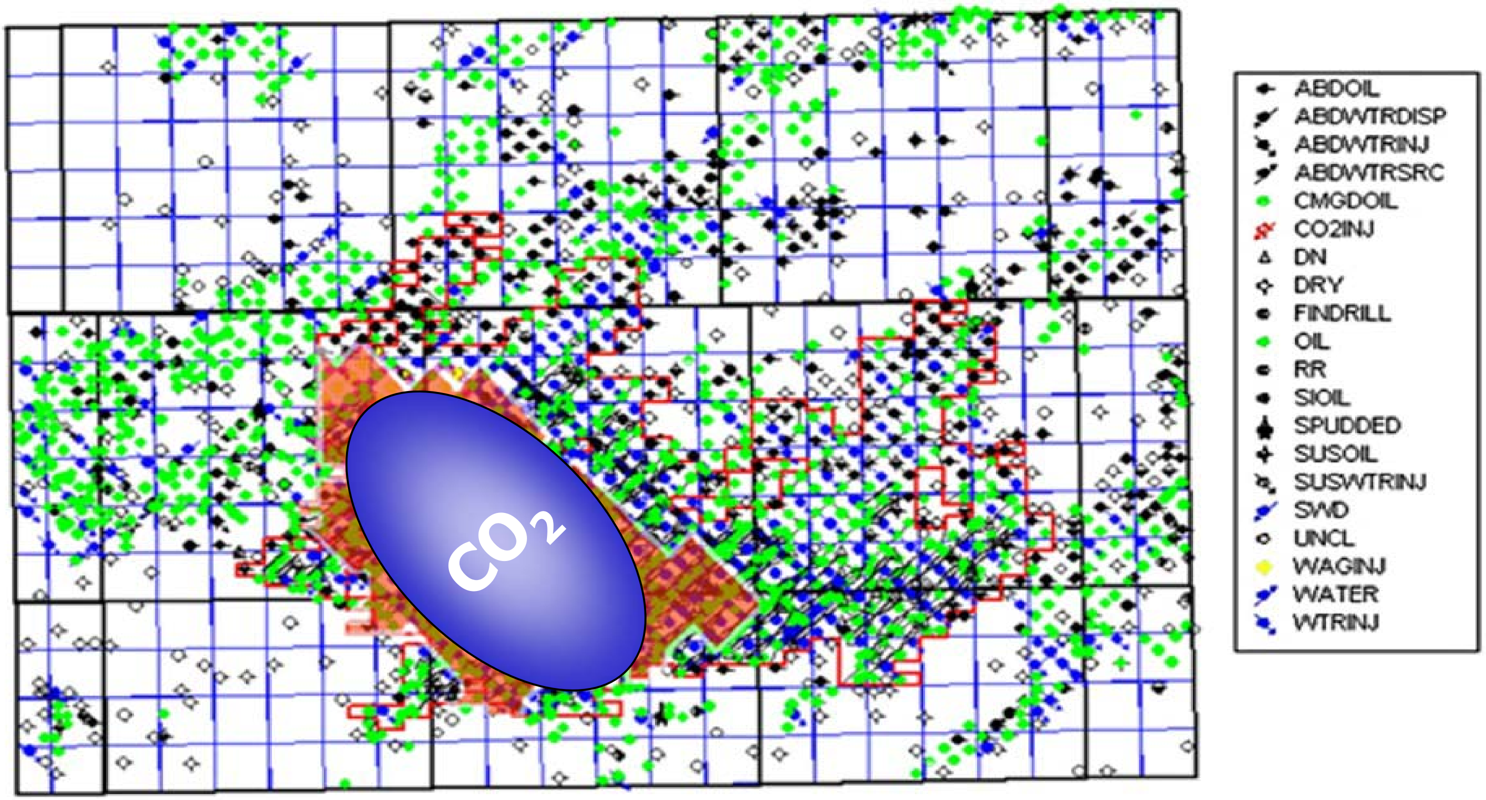
Well Types


Microsoft Excel - STATISTICS(ALL-WELLS)
SIZE-HISTOGRAM
GRADE-HISTOGRAM

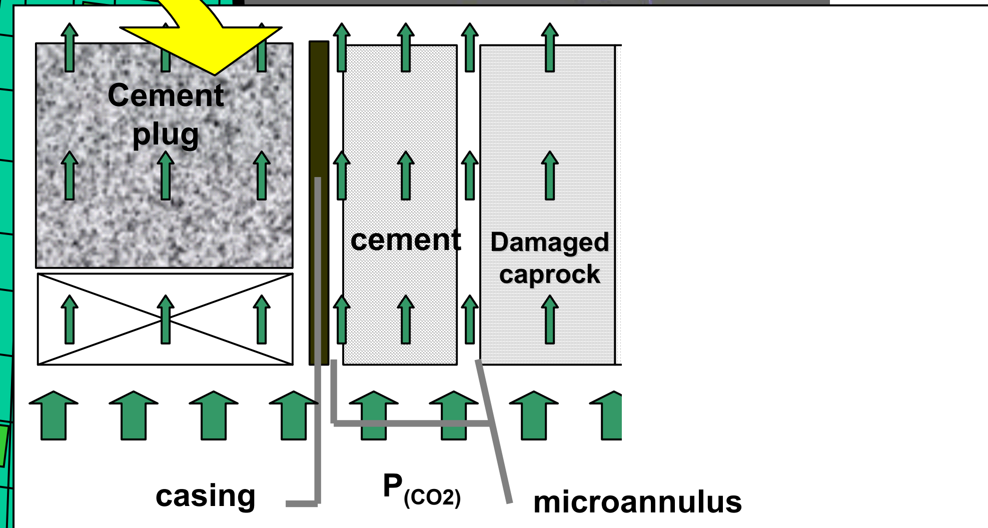

Wellhead
Cement
Annulus Cement
Production Casing
Surface Casing
Production Casing
Casing
Cement
Perforations
Water Injection
Water and Oil
Production
Casing
Cement
Water, Oil and
CO_2 Production
Casing
Corrosion Inhibiting Fluid
Injection Tubing
Bridge Plug
Corrosion Resistant
Inconel Casing
CO_2 Injection

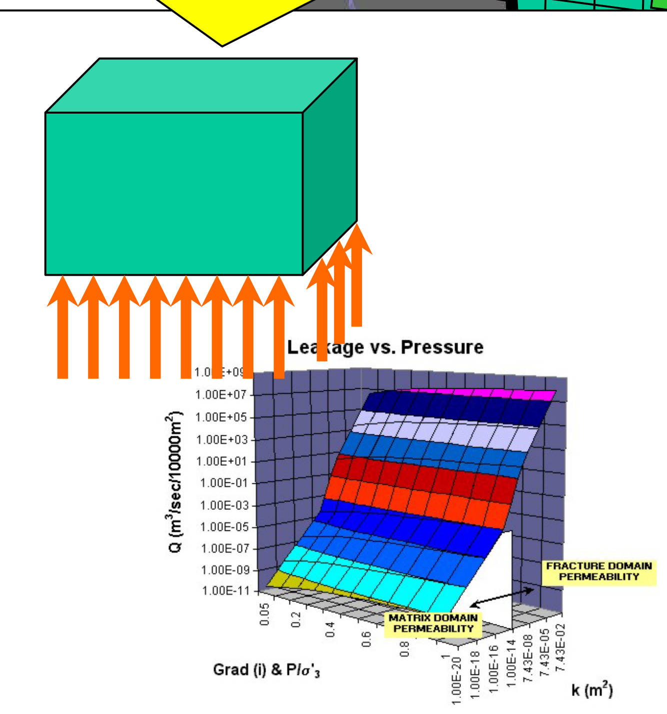
The Performance Assessment Challenge – Lots of Wells!!!

IEA Weyburn CO_2 Monitoring and Storage Project

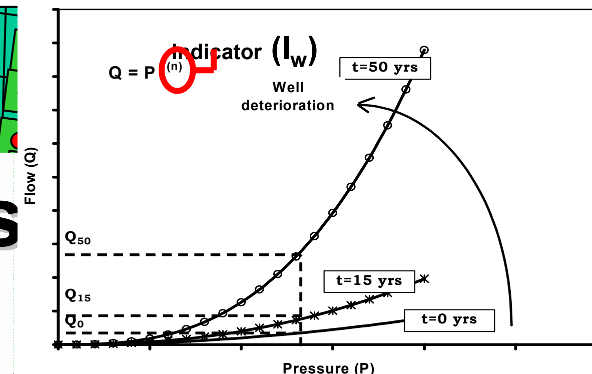


Wellbore System Integrity





Caprock Sys... Integrity



Alberta/Sask Reg.'s

Abandonment Options for Wells not Penetrating Oil Sands

(thermal cements are used in most options for wells penetrating oil sands)

Alberta

Option 1 – Setting a Bridge Plug

1. Set plug < 15 m above the completion zone
2. Pressure test plug at 7000 kPa (1000 psi) for 10 minutes
3. Cap with 8 m of Class "G" cement or 3 m of hydromite

Option 2 – Setting a Cement Retainer

1. Set plug 15 m above the completion zone
2. Pressure test plug at 7000 kPa (1000 psi) for 10 minutes
3. Cement squeeze into completion zone
4.

O

1 ... ne

2

3

O

1

2

3. Pressure test plug at 7000 kPa (1000 psi) for 10 minutes
4. Plug must extend 15m above and below completion zone

Option 5 – Setting a Cement Plug

1. Set plug 15 m above and below completion zone
2. Confirm cement plug top
3. Pressure test plug at 7000 kPa (1000 psi) for 10 minutes

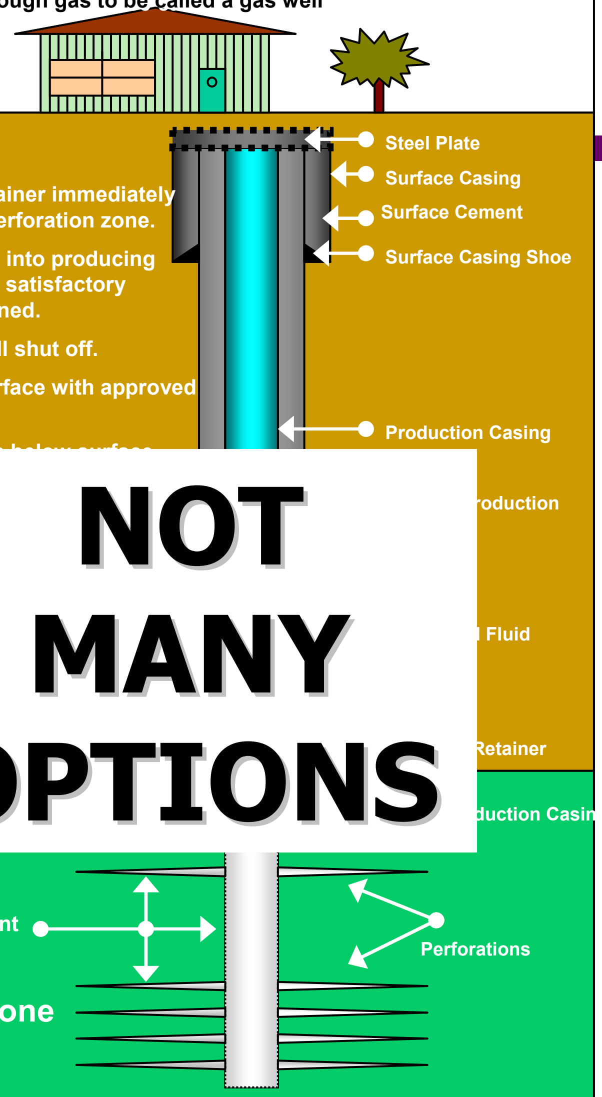
LOTS OF OPTIONS

A well that is to be abandoned after production casing has been set and:

- there is a danger of fluid communication through annular cement; or
- the well produces enough gas to be called a gas well

Steps

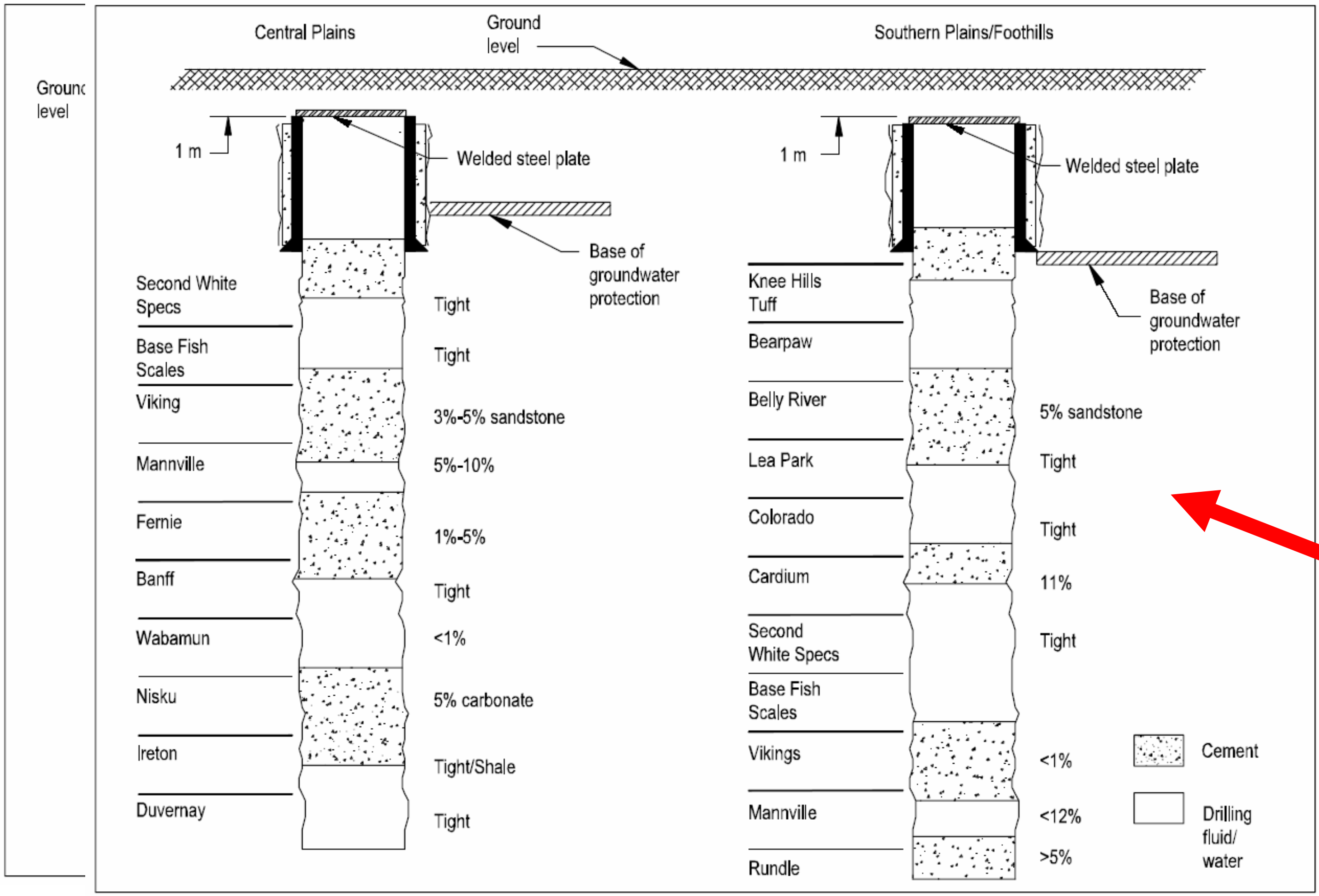
1. Set cast iron retainer immediately above highest perforation zone.
2. Squeeze cement into producing formation until a satisfactory pressure is attained.
3. Test plug for well shut off.
4. Fill casing to surface with approved fluid.
5. Cut of
6. Well st
7. Restor

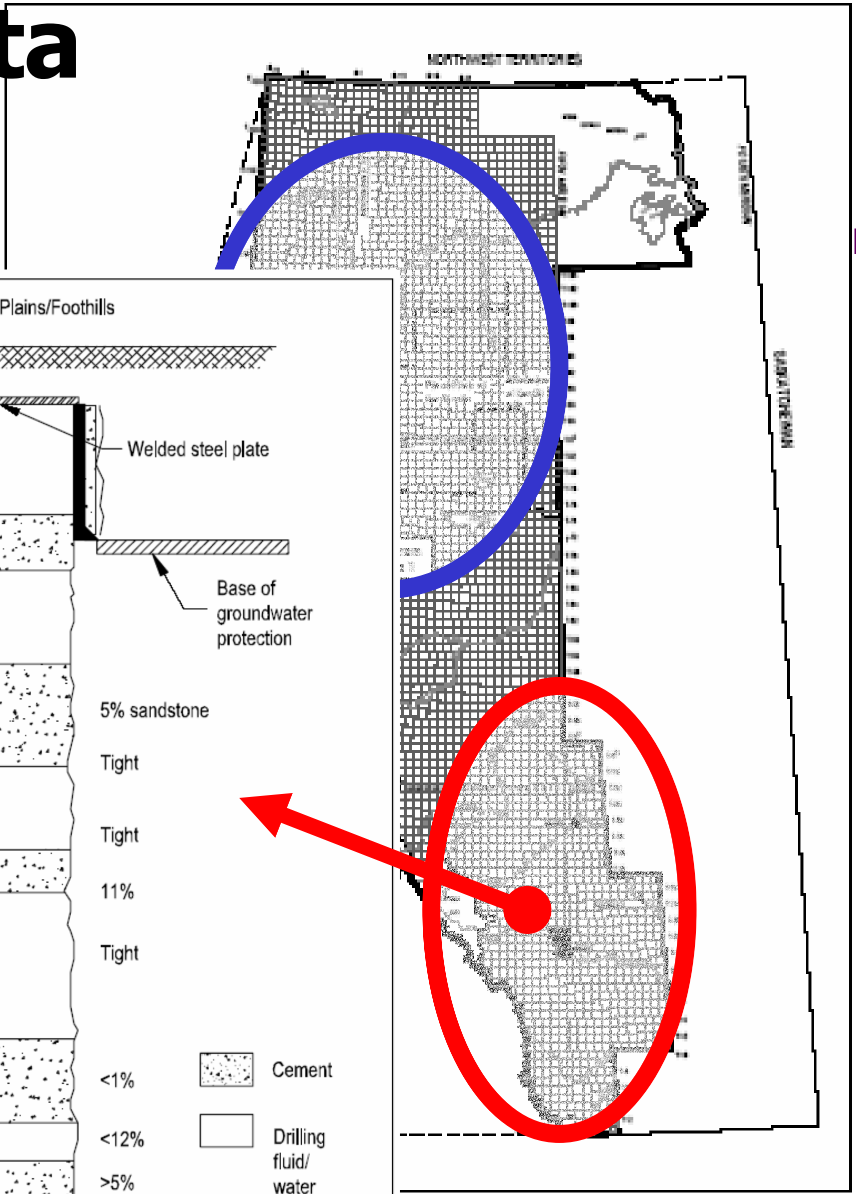


NOT MANY OPTIONS

Saskatchewan

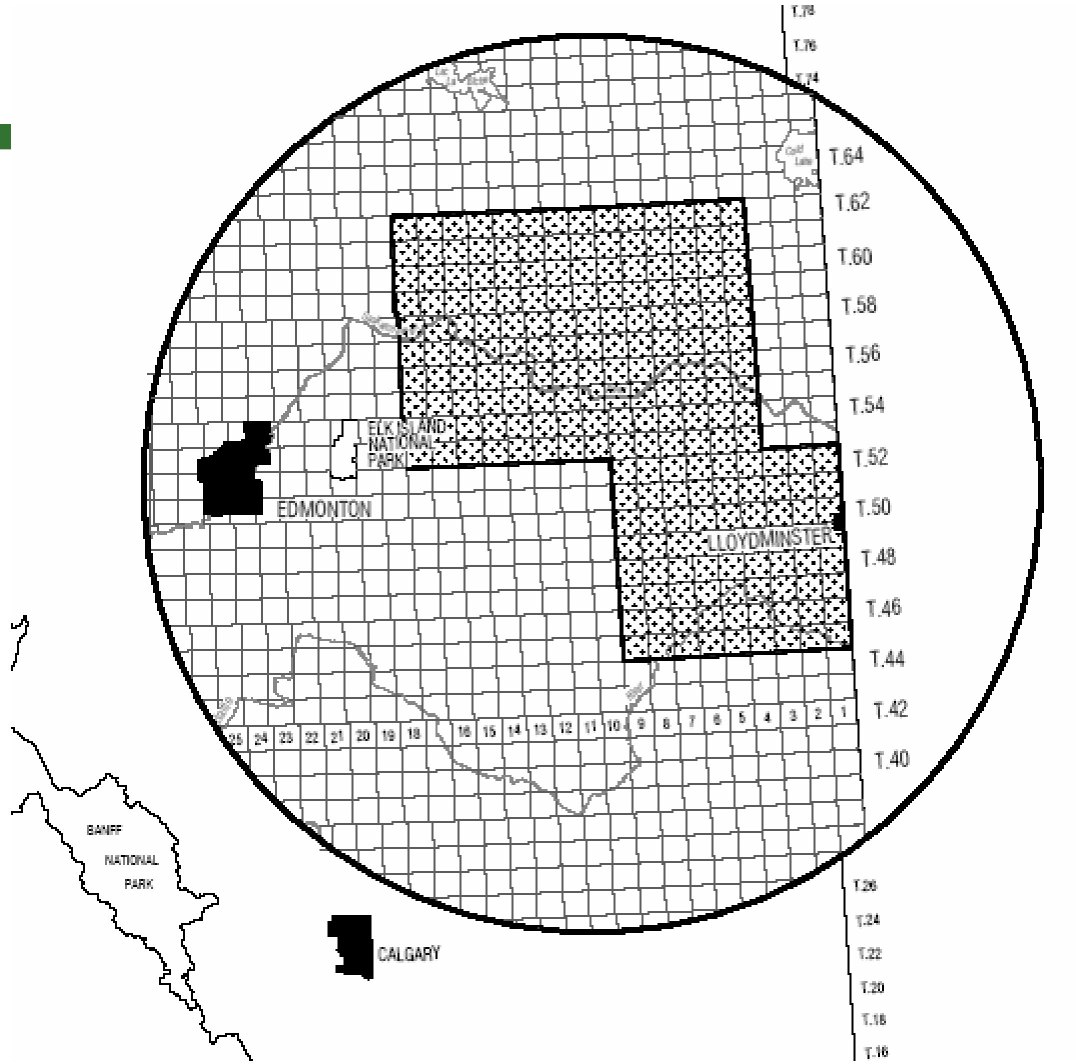
Abandonment: Alberta Guide 20





Guide 20 – Gas Migration Test

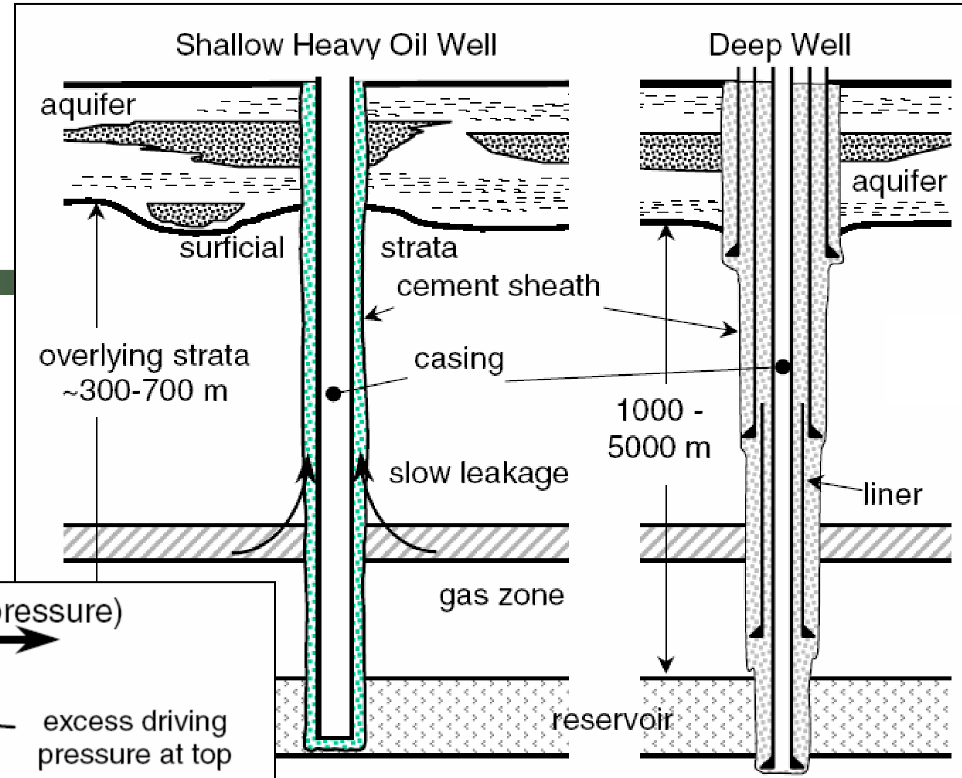
- The licensee must conduct a gas migration test in the **required test area** to determine if gas is detectable outside the outermost casing string. As required in ID 2003-01, a licensee must check all wells in the required test area (see Figure 12) for gas migration prior to surface abandonment. **Although not a requirement, the EUB believes all wells should be tested for gas migration prior to abandonment.**

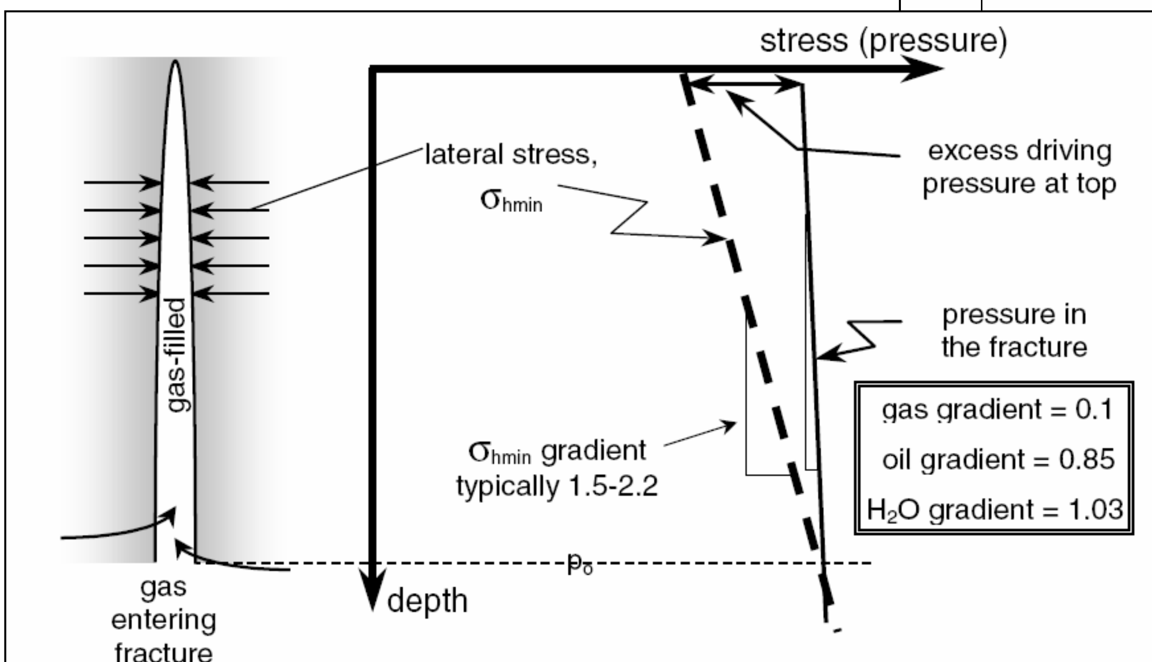


T.64
T.62
T.60
T.58
T.56
T.54
T.52
T.50
T.48
T.46
T.44
T.42
T.40
ELK ISLAND NATIONAL PARK
EDMONTON
LLOYDMINSTER
25 24 23 22 21 20 19 18 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1
BANFF NATIONAL PARK
CALGARY
T.26
T.24
T.22
T.20
T.18
T.16

Another Mechanism….

Gas Filled Fracture





From Dusseault et al., 2000 SPE 64733

Overview of Report to MMS

"Diagnosis and Remediation of Sustained Casing Pressure in Wells"

July, 2001

Walter Crow / BP

Conclusions of Report

Background

- Study conducted by Louisiana State University for Mineral Management Service (MMS) – 2001
  - Data from Gulf of Mexico wells
- Evaluated the approach to resolve SCP by **hydrostatic balance** of the fluid in the casing annulus with formation pressure
- Reviewed two methods to increase hydrostatic gradient:
  - "Bleed and Lube" method – mulitiple cycles of bleed off pressure (gas) and inject kill weight fluid - limited success
  - "Casing Annular Remediation System" (CARS): Flexible tube inserted through casing valve to circulate fluid – shallow depth access limits use

Conclusions of Report

Context for Gulf of Mexico Study

- SCP widespread: 11,500 casing strings in 8100 wells
  - Gas migration through the cement shoe(s)
  - Tubing leak to the casing annulus
  - 90% of cases can be controlled with casing strength
    (as long as at least one string maintains a seal to atmosphere)
- Surveillance options limited
  - Limited log capability to detect source and length of channels

Relevance

- Does not address CO_2 as a cause or contributor to SCP
- Historically, the solution is a remedial measure using a fluid barrier

Conclusions of Report

- Lack of direct access is problematic for remedial treatment of annuli
- Rig repair for outer casing annuli <50% effective because of limited injectivity to channel for cement placement.
  - Cement design not conducive to travel through small channels
- Process to kill SCP by lubrication
  - Best results when casing annulus fluid and kill fluid are immiscible
  - Water-based mud containing gel becomes viscous in contact with brine – (most wells drilled with this type of fluid)

Well Integrity Context

- Drilling systems include **hydrostatic** and **mechanical** barriers
  - Hydrostatic fluid under primarily circulating conditions
  - Surface BOP and cement shoe provide “mechanical” seal
- Production systems typically are only mechanical
  - Wellhead
  - Cemented annuli

Testing & Analysis of SCP

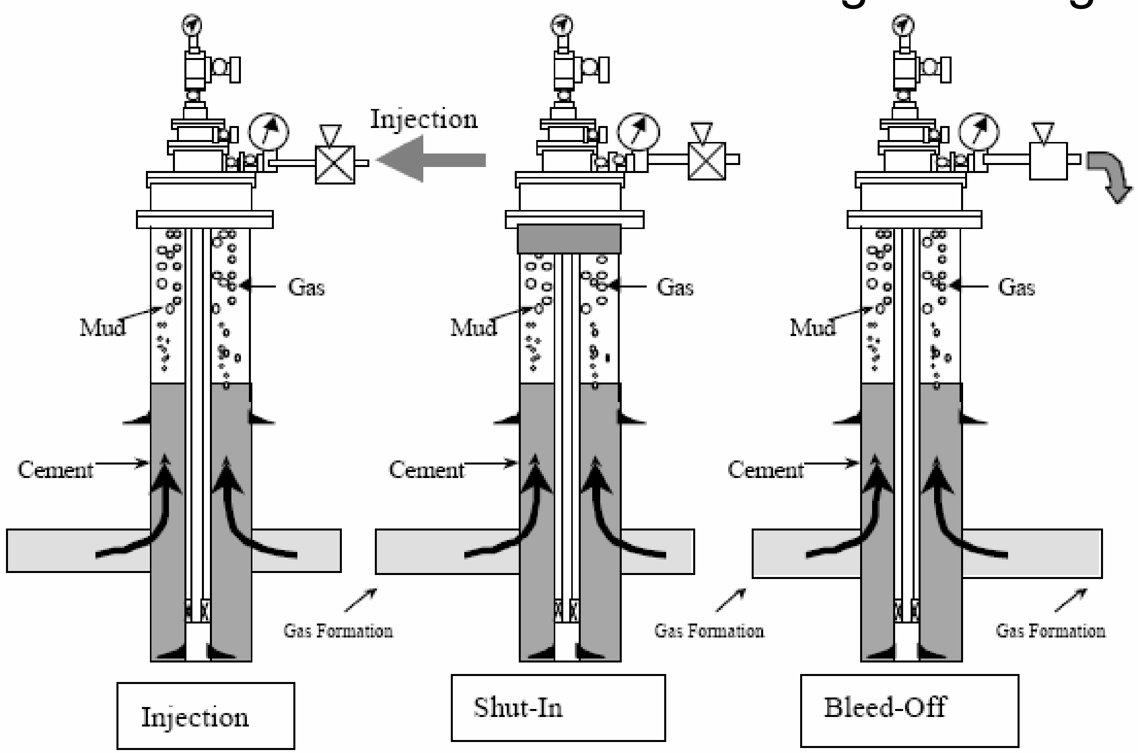
- Bleed and monitor pressure if SCP is present or if pressure changes
- Diagnosis required on all annuli if any one of them has SCP
- Repair required if:
  - SCP exceeds 20% of internal yield
  - Cannot be bled to 0 psi through a ½” valve in 24 hrs
- Mechanisms of gas migration
  - Matrix permeability of cement
  - Interfacial channeling through microannulus

Diagnosis of SCP

- Statistical analysis of one field showed trend similar whole Gulf of Mexico
- Gas flow through unset cement matrix is believed to be major cause of SCP
  - Cement shrinkage is considered as a contributor
- Analysis can be simplified if unknown parameters limited to:
  - Cement conductivity
  - Formation pressure

Remediation of SCP – Bleed & Lubricate

- Bleed small volume of gas/fluid; inject high density brine
  - Attempt to increase hydrostatic pressure in annulus
  - Creates pressure cycle
  - Unsuccessful if annular fluid contains gel or weight material



Remediation of SCP – Bleed & Lubricate

- Field experience – Primarily Unsuccessful
  - Only partially reduced SCP
  - Pressure cycles sometimes increased casing pressure
- Experimental Tests
  - Best results » annular fluid immiscible with kill weight fluid
  - Water-based drill mud (with gel) flocculates when exposed to brine kill weight fluid

Removal of SCP – Casing Annulus Remediation

- Casing Annulus Remediation System (CARS)
- Insert circulation tube through casing valve
  - Pump high density fluid through small diameter tube
  - Depth limit <1000 feet of penetration in field cases
  - Depth limit is a barrier to use

MMS Study on Sustained Casing Pressure

- Focus on SCP remediation by hydrostatic control
  - Results of fluid placement insufficient to solve SCP
  - Bleed and lubricate method inherently allows gas release
- Elimination or control of SCP consistent with goal of CO_2 containment
  - SCP = risk of pollution to ocean water and environment
- Should hydrostatic control be considered a permanent or long-term well integrity barrier for CO_2 storage?
  - Increase in bottomhole pressure due to gas injection

Overview of
Diagnosis and Remediation of SCP

Questions?

American Petroleum Institute

New API Practices to Isolate Flow Zones

By

Ron Sweatman, Chairman of API Work Group

Presented at

2nd Well Bore Integrity Network Meeting

Princeton University

28-29 March, 2006

Organised by:

IEA GREENHOUSE GAS R&D PROGRAMME

bp

Princeton University

Presentation Summary

- API Work Group on Flow Prevention and Remediation
- Studies of SWF, LWC and gas flow causes
    - >120 studies reviewed & 34 referenced in Part 2
    - 14 MMS & operator reports on LWC incidents
- API RP-65 on Preventing & Remediating Flows
    - ➢ Parts 1 and 2 overviews for Annular Flows
    - ➢ Part 3 scope for Casing Pressure (SCP/APB/TCP)
    - ➢ Best practices and lessons learned
    - ➢ Pending MMS regulations for APD (Application for Permit to Drill)
    - ➢ Cost Benefits
- API RP-90 on Casing Pressure Management

API Work Group on Prevention & Remediation

- Started summer of 2000
- 57 organizations
- 114 members
- MMS Challenges to Work Group
  - Study how to reduce LWC incidents and CP
  - Publish improved zone isolation practices
  - Help reduce cases and risk of LWC and CP
  - Lead effort to prevent annular flows & migration
  - Recommend remediation practices

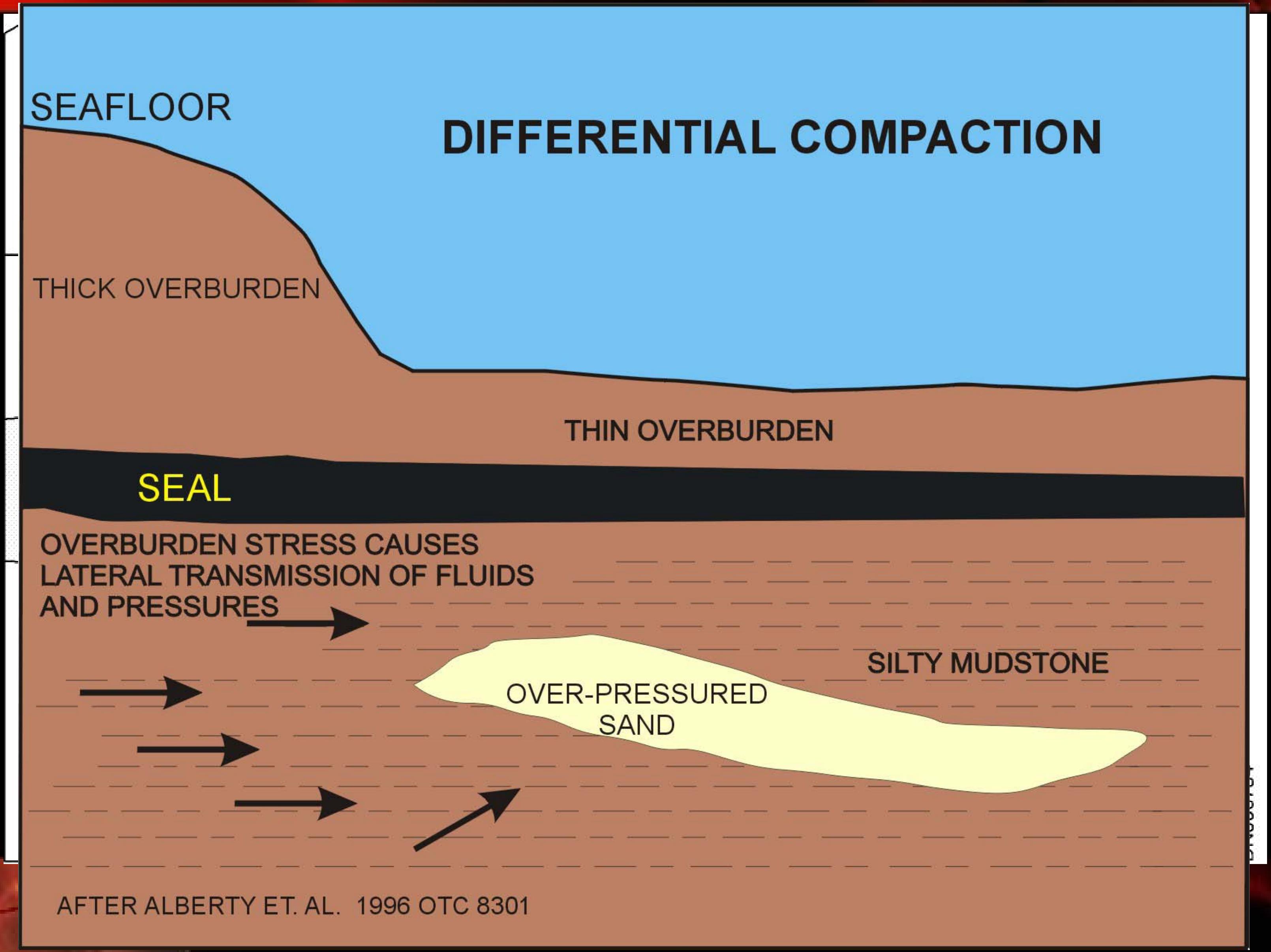
Annular Flow & Casing Pressure Study

"New API Practices for Isolating Potential Flow Zones During Drilling and Cementing Operations"

SPE 97168 & JPT January 2006

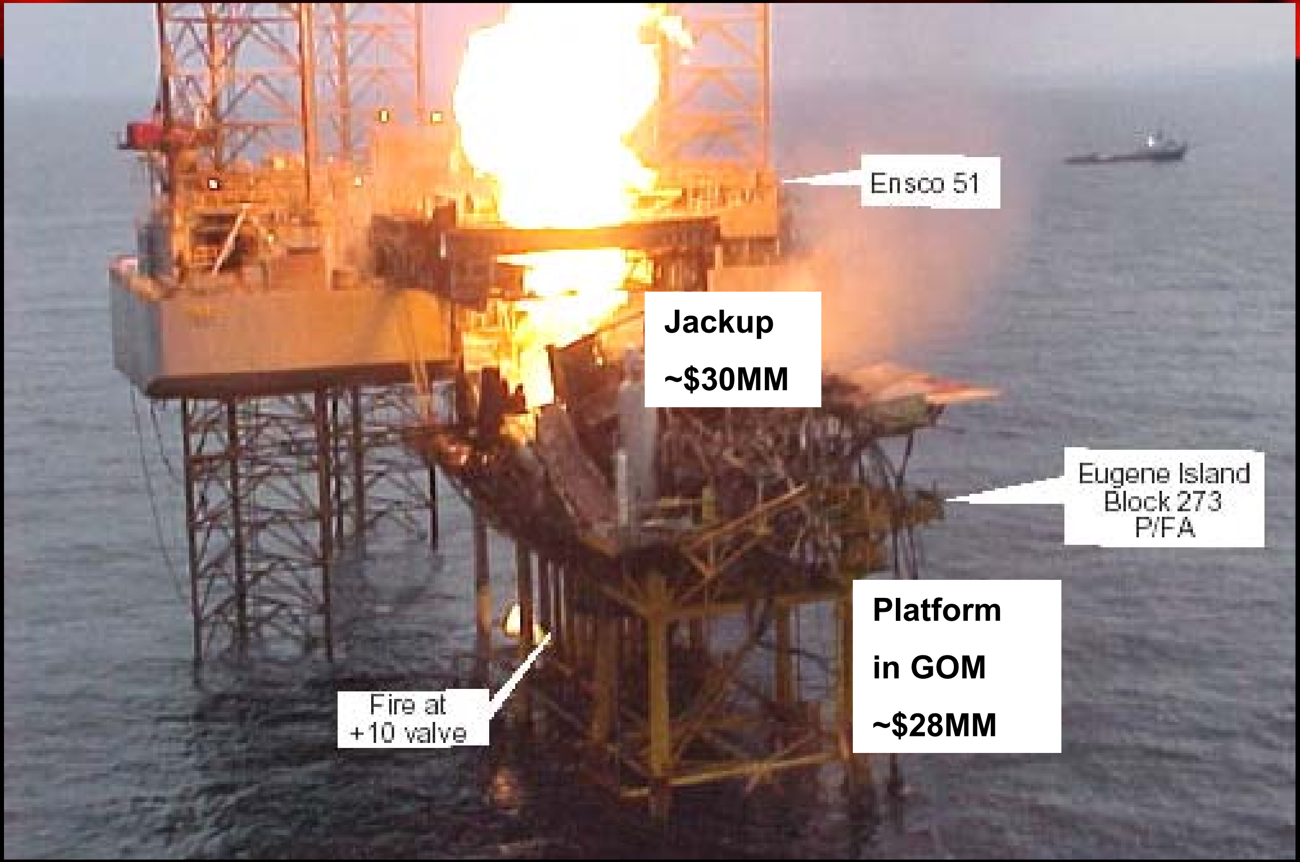
By Moss Bannerman, Chevron; Jerry Calvert, Consultant; Tom Griffin, Griffin Cement Consulting LLC; Joe Levine and John McCarroll, MMS; Dan Postler, Devon Energy; Andy Radford, API; Ron Sweatman, Halliburton

Shallow water and/or gas flow through the annulus



High Costs of Loss of Well Control Incidents

56% of LWC incidents (19 of 34) in 1996-2001 period linked to cementing operations



LWC by MMS &
wells by Spears

OCS Events	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
LWC vs. wells drilled	4 of 1185	5 of 1274	7 of 1246	5 of 1242	9 of 1412	10 of 1516	6 of 1119	5 of 1075	4 of 965	4 of ~966

SCP sources

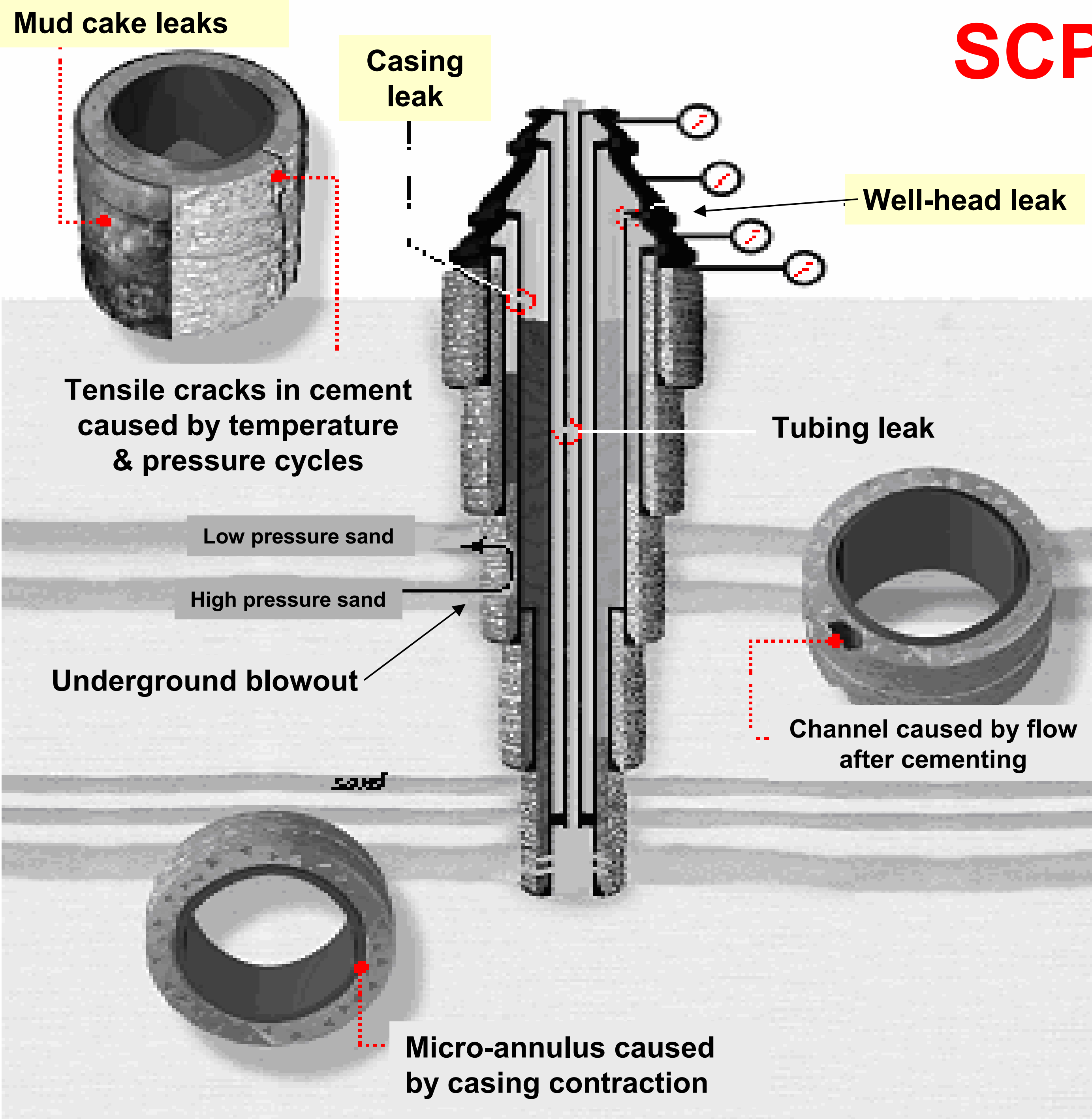
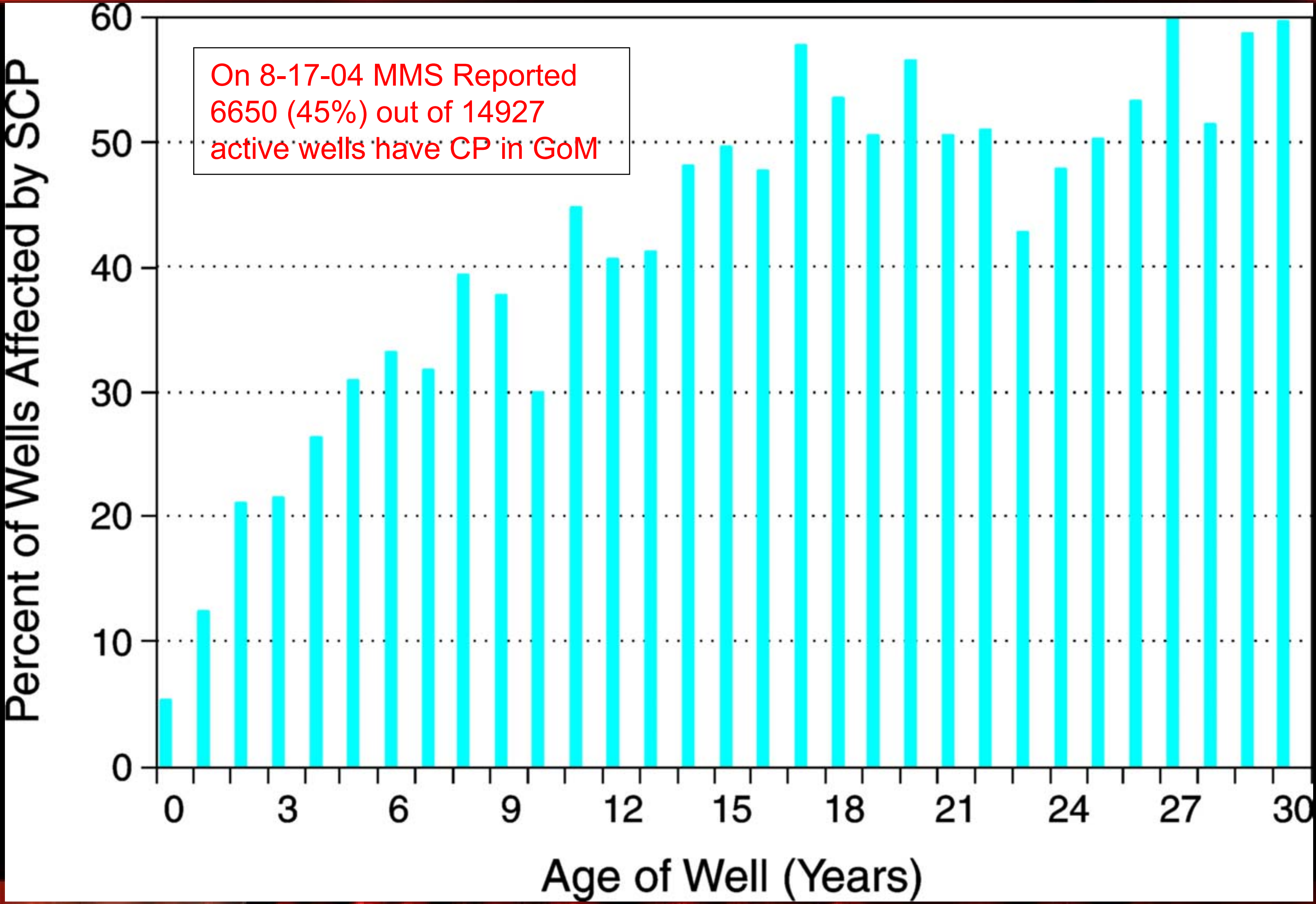


Figure from "A Review of Sustained Casing Pressure (SCP) Occurring on the OCS" by Bourgoyne et al (March 2000)

Gulf of Mexico wells with contained SCP reported by MMS on 2-17-03 (15,773 active wells)

(% wells changes by old well abandonment & new wells drilled)



~33% of SCP wells linked to the cementing process

Work Group Charges

- Prepare API RP 65 (Part 1—published 2002)
  - Study SWF event prevention in deepwater
  - Recommend zone isolation process
- Prepare API RP 65 (Part 2—in review)
  - Study LWC event prevention
  - Recommend zone isolation process
  - All offshore wells
- Prepare API RP 65 (Part 3—in process)
  - Study SCP and TCP prevention and remediation
  - Recommend zone isolation process
  - All wells

API RP-65 Part 1

- Potential SWF event consequences
  - Loss of well integrity:
    - Hole enlargement/collapse
    - Casing damage
    - Pressure communication
  - Seafloor craters, mounds, crevasses
  - Loss of templates
  - Pollution
  - Gas hydrate destabilization

Studies of Deepwater SWF in GoM

(Costs in Millions USD)

Study of wells in known SWF areas	123 wells in 1998 report	106 wells in 1999 report
SWF Remediation Costs	$137	$116
SWF Prevention Costs	$30	$59
Total Costs	$167	$175

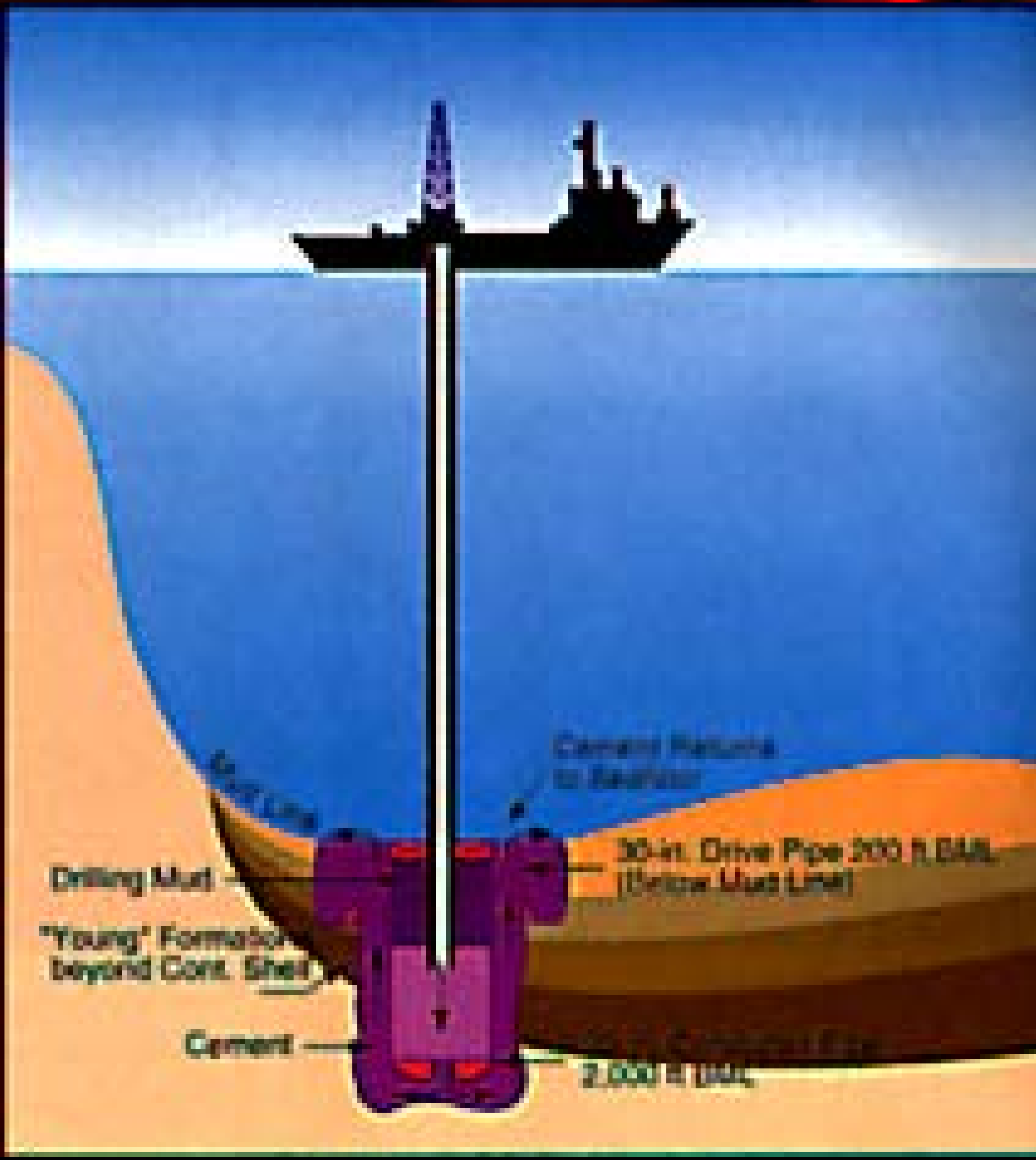
1. Data from study reports by Mark Alberty with BP and published in several papers including OTC11971.
2. The 106 wells is a subset of the 123 wells studied.

SWF Challenges

- PP ~= FP
- Narrow mud weight window
- Seawater drilling fluid
- Riserless drilling - wellhead flow control
- ROV-only observation
- Batch-set conductor/surface casing proximity
- Cold water temperature

Best Practices

- Site selection for minimal SWF
- PWD and resistivity tools
- ROV to check flow
- Swift reaction to contain flows
- Mud for flow control
- Pad mud before casing
- Special cement slurries



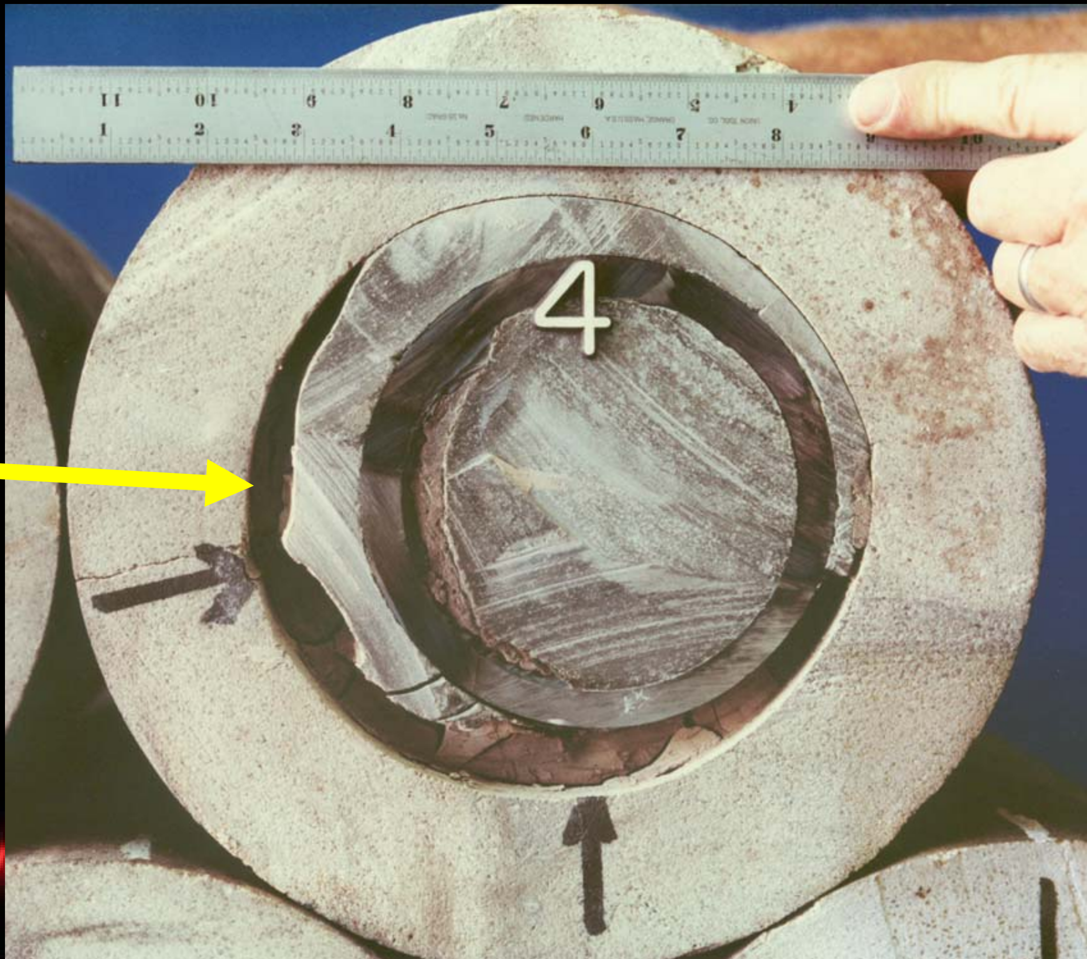
Lessons Learned

- PP control at first indication of SWF
- Zones drilled UB not isolated with cement
- Delayed control of SWF jeopardizes the well
- Cement must be designed to control SWF
- Mechanical barriers alone may not seal long term

API RP-65 Part 2 Objectives

- Control of flows and losses – MAINTAIN OVERBALANCE
  - Prior to, during & after cementing operations
- Prevention of LWC incidents in the short term
- Help prevent casing pressure & loss of well integrity (long term)

Gas migration through mud channels in cement



LWC Incident Characteristics

Based on 14 of 19 Cases Linked to Cementing:

- Immediately after cementing surface casing
- Failure to maintain HH and overbalance
- Mudline hanger
- Cleaning cement out of annulus
- Lost or partial circulation lowers TOC
- Cement slurry not designed for gas control
- Mud removal/ZI practices inadequate

Well Design and Drilling Practices – Part 2

- Flow-potential evaluation
- Optimize well plan & design
  - PP, FG, MW analysis
  - Annular clearances for ECD control
  - Drill a smooth, non-spiraling hole
  - Control/isolation of flow/loss zones
  - Wellbore cleaning
  - Primary/secondary barrier designs
  - Contingency plan
  - Communication to personnel

Well Design and Drilling Practices – Part 2

- ID potential flows/losses
- Mechanical barriers vs. HH
  - Seal set after WOC
  - Place seal top of zone
- Cementing practices
  - Hole/pipe geometry
  - Narrow flow paths
  - Drilling fluid removal
  - Casing hardware
  - Engineering design
  - Slurry design and testing
- Post-cementing operations
  - Stable HH
  - WOC decision tree
  - Top job
- Post-job evaluation
- Leakoff tests
  - LOT
  - FIT

RP-65 Part 3

"Zone Isolation to Prevent & Remediate Casing Pressure"

Addresses CO_2, H_2S, & Hydrocarbon Containment

- Preventive Practices During Drilling & Completion
  - ✓ Well Planning & Design also refers to API RP-90
  - ✓ Diagnostics to Find SCP Source Zones & TCP Traps
  - ✓ SCP Source Zone Permeability Barriers
  - ✓ Mechanical Barriers
  - ✓ Cementing Barriers
  - ✓ Well Integrity Testing (Pipe, Shoe, Lap, Packer, etc.)
- Remedial Practices for Workovers & Abandonment
  - ✓ SCP Diagnostics During Production
  - ✓ Annular Sealing Methods and Materials
  - ✓ SCP Source Zone Permeability Barriers

RP-65 Part 3: Example Study & Peer Review

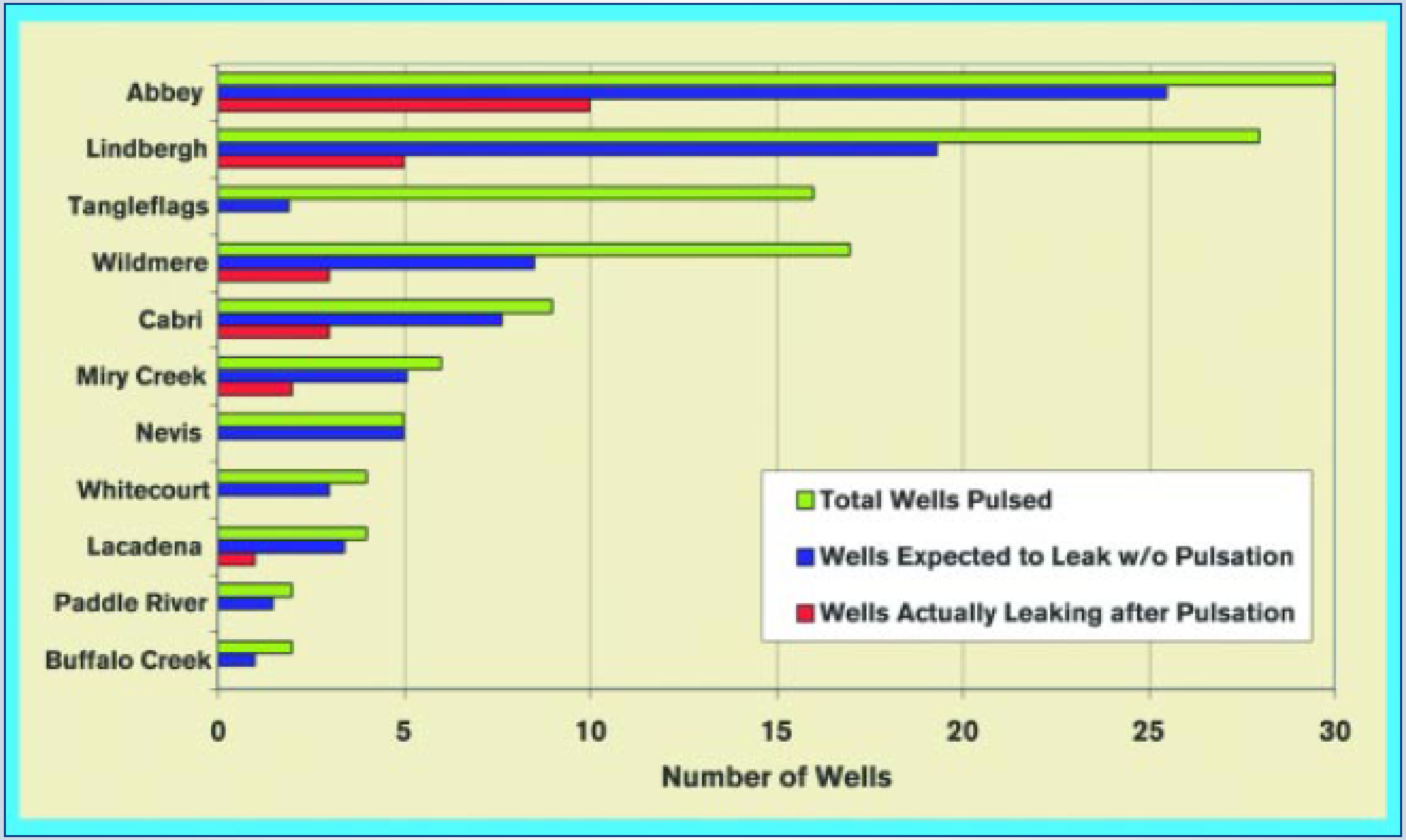


Figure 3: Summary of the Top 11 Fields Pulsed in Canada

Pulsation Technology Application reported by Lang, K.: "March: Production Optimization: Pulsation improves cementing results," article in Hart's E&P, March 2003

In 2006, the MMS may publish a proposed rule incorporating API RP-65 Part One

"Cementing Shallow Water Flow Zones in Deep Water Wells."

MMS would require RP-65 practices to approve APD

and

The International Standards Organization wants to adopt API RP-65 as an ISO Standard Practice

Annular Flow Costs vs. RP-65 Benefits
(estimated USD per well)

- **Loss of well control and SWF incidents**
  - Remediation ranges ~$1,600,000 to >$100,000,000
  - RP-65 prevention cost benefits
    - Helps save remediation cost
    - Prevention ranges ~$240,000 to $1,540,000
- **Casing pressure (SCP and TCP)**
  - Management averages ~$100,000 each year
  - Remediation ranges ~$100,000 to >$2,000,000
  - RP-65 prevention cost benefits
    - Helps save management and remediation Costs
    - Prevention ranges ~$50,000 to $280,000

API RP-90

"Annular Casing Pressure Management for Offshore Wells"

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

American Petroleum Institute

Helping You Get The Job Done Right.®

Questions, Suggestions, and Comments are Welcome

Key Cementing Parameters for Shallow Water Flow Hazards in Deep Water

Parameter	Recommended Criteria	Max Points	Plan Score	Performance Score	Actual Value
Site Selection					
Site Selection	Site is analyzed to minimize potential for flow by Appendix A or equivalent process	10			
	Total	**10**	**0**	**0**	
Critical Fluid Parameters					
Gel Strengths of Pad Mud @ BHT	10 second, 10 minute and 30 minute gels all < 25 lb/100 ft^2	4			
Density	Sufficient to control flow	4			
Fluid Loss	Pad Mud <15 API	2			
	Total	**10**	**0**	**0**	
Critical Well Parameters					
Hole Diameter	Hole diameter is a minimum of 3.0 inches greater than the casing outer diameter	2			
Clearances	Wellhead/cased hole inner diameters are a minimum of 1 inch greater than casing/casing connector outer diameter at all points in the wellbore.	2			
Rathole	Rathole is filled with mud with density greater than cement	2			
Flows	Action is taken to kill flow as soon as encountered	8			
End of inner string	Within 80 feet of shoe	2			
	Total	**16**	**0**	**0**	

Critical Operational Parameters					
Lost Circulation	Full returns are maintained and fracturing initiation pressure is not violated at any time while running pipe or during conditioning and cementing	3			
Static Time	Pressure test lines before conditioning and < 5 minutes of non-circulation time from start of mud circulation until completion of cementing operation	2			
	Total	**5**	**0**	**0**	
Critical Displacement Efficiency Parameters					
Mixing and Placement Rate	Circulation rate in annulus before and during cementing meets mud removal criteria established by computer simulation	3			
Centralization	Optimized for mud removal through SWF zone	3			
Spacer	Optimized density and volume for 500 feet annular fill	2			
Fluid compatibility tests	Compatible	2			
Mud Conditioning Volume	> 1 Annular Volume	3			
Well control	There is no flow before or during conditioning and cementing	5			
Pipe Movement	Pipe is moved to enhance mud displacement	2			
	Total	**20**	**0**	**0**	

Critical Cementing Fluids Parameters					
Temperature for Cement Testing	Temperatures established by measurement and/or thermal modeling software	5			
Slurry Design	Compressible slurries are used	5			
	Gel strength development meets maximum time requirements	4			
	Reduced fluid loss slurries are used	2			
	WOC criteria established and followed	4			
	Cement density appropriate for well conditions	3			
	Slurry stability (Free fluid, sedimentation and foam stability meet criteria)	3			
Blend verification	According to quality plan (vendor's or operator's)	3			
Cement Top	Returns of cement are observed at mud line and calculated top of high performance cement is above SWF zone	3			
Rheological Relationships	Friction pressure of each laminar flow fluid is greater than the fluid it is displacing in all parts of the hole.	3			
	Total	**35**	**0**	**0**	
Critical Cementing Equipment					
Cement Mixing Equipment	Computer assisted density controlled mixer or batch mixer	2			
Nitrogen Injection (foamed cement)	Automated, process controlled injection equipment	3			
Foamer and nitrogen at proper ratio	Within 10% of design	4			
Bulk cement delivery	No mixing constraints or interruptions due to bulk delivery problems	3			
Density Control	+/- 0.2 lb/gal	4			
	Total	**16**	**0**	**0**	
	SHEET TOTAL	**112**	**0**	**0**	

Costs to Prevent SWF by Alberty

(Per Well Average Cost Based on 106 wells)

MWD/PWD (in RP)	$20,000
24/26" Casing (not in RP)	$500,000
Pilot Holes (optional)	$300,000
SWF Cement (in RP)	$200,000
Riser (in RP)	$500,000
Well Planning (in RP)	$20,000
TOTAL EXPENSE / Well	$1,540,000

Total/Well for RP-65 Part 1 is ~$740,000

NOTES: 1. Expense may vary depending on conditions.
2. Details in paper "The Business and Financial Impact of SWF on Deepwater Operations," by Mark Alberty, BP presented at 1999 Int'l Forum on Shallow Water Flows in League City, TX.

WG Members Represent Organizations (#)

- Oil & Gas Operator Companies (20)
- Offshore Operators Groups (2)
- Drilling Contractors Association (1)
- Independent Operators Association (1)
- Petroleum Technology Transfer (1)
- Government Regulators (1)
- Industry Standardization (3)
- Drilling Contractors (3)
- Cementing Services (3)
- Cement Manufacturers (1)
- Consultants (8)
- Drilling Fluids (2)
- Research / Technical Services (5)
- Well Control (4)
- Wellhead Manufacturer (1)
- Universities (1)

Work Group Members Are Liaisons to:

1. MMS
2. IADC
3. DEA
4. IPAA
5. API SC-10 on Cementing
6. API SC-13 on Drilling & Completion Fluids
7. API Deepwater Operations Steering Committee
8. API Executive Committee
9. CEA-140 (MMS - JIP on SCP Cement)
10. OOC SCP Group on RP-90
11. OOC (Offshore Operators Committee)
12. PTTC
13. ISO
14. DeepStar
15. SWF/Geohazards JIP

Conclusions of Report

Background

- Study conducted by Louisiana State University for Mineral Management Service (MMS) – 2001
  - Data from Gulf of Mexico wells
- Evaluated the approach to resolve SCP by **hydrostatic balance** of the fluid in the casing annulus with formation pressure
- Reviewed two methods to increase hydrostatic gradient:
  - "Bleed and Lube" method – mulitiple cycles of bleed off pressure (gas) and inject kill weight fluid - limited success
  - "Casing Annular Remediation System" (CARS): Flexible tube inserted through casing valve to circulate fluid – shallow depth access limits use

Conclusions of Report

Context for Gulf of Mexico Study

- SCP widespread: 11,500 casing strings in 8100 wells
  - Gas migration through the cement shoe(s)
  - Tubing leak to the casing annulus
  - 90% of cases can be controlled with casing strength
    (as long as at least one string maintains a seal to atmosphere)
- Surveillance options limited
  - Limited log capability to detect source and length of channels

Relevance

- Does not address CO_2 as a cause or contributor to SCP
- Historically, the solution is a remedial measure using a fluid barrier

Conclusions of Report

- Lack of direct access is problematic for remedial treatment of annuli
- Rig repair for outer casing annuli <50% effective because of limited injectivity to channel for cement placement.
  - Cement design not conducive to travel through small channels
- Process to kill SCP by lubrication
  - Best results when casing annulus fluid and kill fluid are immiscible
  - Water-based mud containing gel becomes viscous in contact with brine – (most wells drilled with this type of fluid)

Well Integrity Context

- Drilling systems include **hydrostatic** and **mechanical** barriers
  - Hydrostatic fluid under primarily circulating conditions
  - Surface BOP and cement shoe provide “mechanical” seal
- Production systems typically are only mechanical
  - Wellhead
  - Cemented annuli

Testing & Analysis of SCP

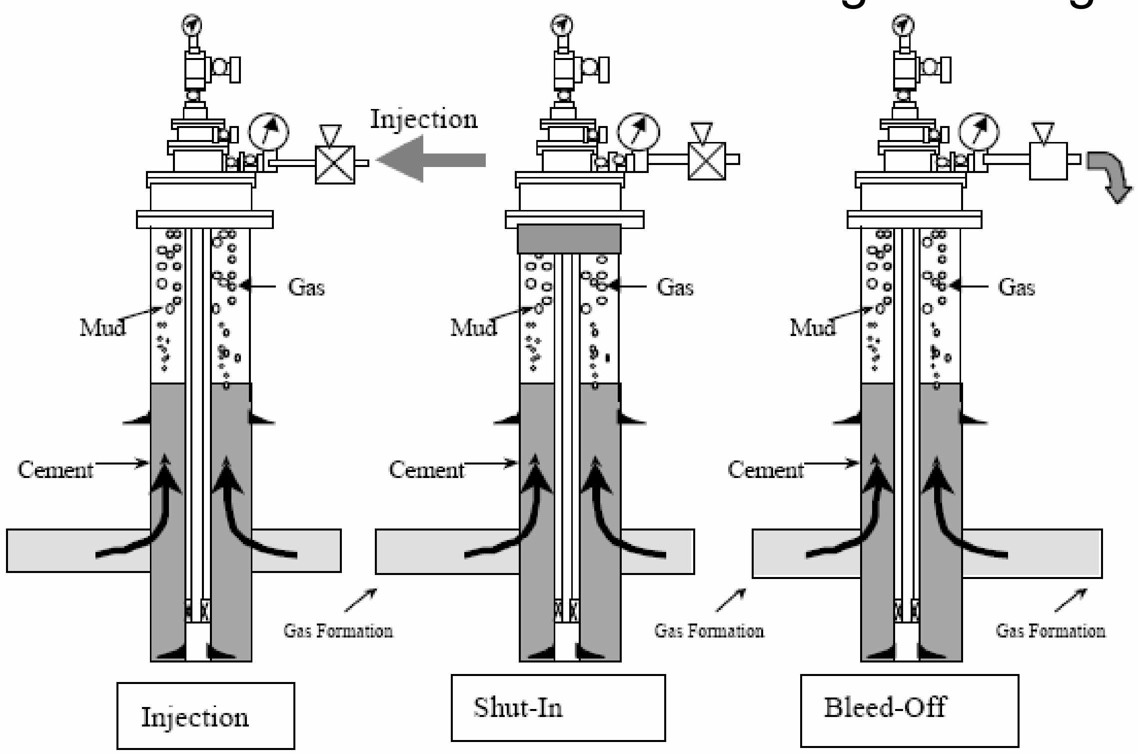
- Bleed and monitor pressure if SCP is present or if pressure changes
- Diagnosis required on all annuli if any one of them has SCP
- Repair required if:
  - SCP exceeds 20% of internal yield
  - Cannot be bled to 0 psi through a ½" valve in 24 hrs
- Mechanisms of gas migration
  - Matrix permeability of cement
  - Interfacial channeling through microannulus

Diagnosis of SCP

- Statistical analysis of one field showed trend similar whole Gulf of Mexico
- Gas flow through unset cement matrix is believed to be major cause of SCP
  - Cement shrinkage is considered as a contributor
- Analysis can be simplified if unknown parameters limited to:
  - Cement conductivity
  - Formation pressure

Remediation of SCP – Bleed & Lubricate

- Bleed small volume of gas/fluid; inject high density brine
  - Attempt to increase hydrostatic pressure in annulus
  - Creates pressure cycle
  - Unsuccessful if annular fluid contains gel or weight material



Remediation of SCP – Bleed & Lubricate

- Field experience – Primarily Unsuccessful
  - Only partially reduced SCP
  - Pressure cycles sometimes increased casing pressure
- Experimental Tests
  - Best results » annular fluid immiscible with kill weight fluid
  - Water-based drill mud (with gel) flocculates when exposed to brine kill weight fluid

Removal of SCP – Casing Annulus Remediation

- Casing Annulus Remediation System (CARS)
- Insert circulation tube through casing valve
  - Pump high density fluid through small diameter tube
  - Depth limit <1000 feet of penetration in field cases
  - Depth limit is a barrier to use

MMS Study on Sustained Casing Pressure

- Focus on SCP remediation by hydrostatic control
  - Results of fluid placement insufficient to solve SCP
  - Bleed and lubricate method inherently allows gas release
- Elimination or control of SCP consistent with goal of CO_2 containment
  - SCP = risk of pollution to ocean water and environment
- Should hydrostatic control be considered a permanent or long-term well integrity barrier for CO_2 storage?
  - Increase in bottomhole pressure due to gas injection

Overview of Diagnosis and Remediation of SCP

Questions?

Exploration & Production **Technology**
delivering breakthrough solutions

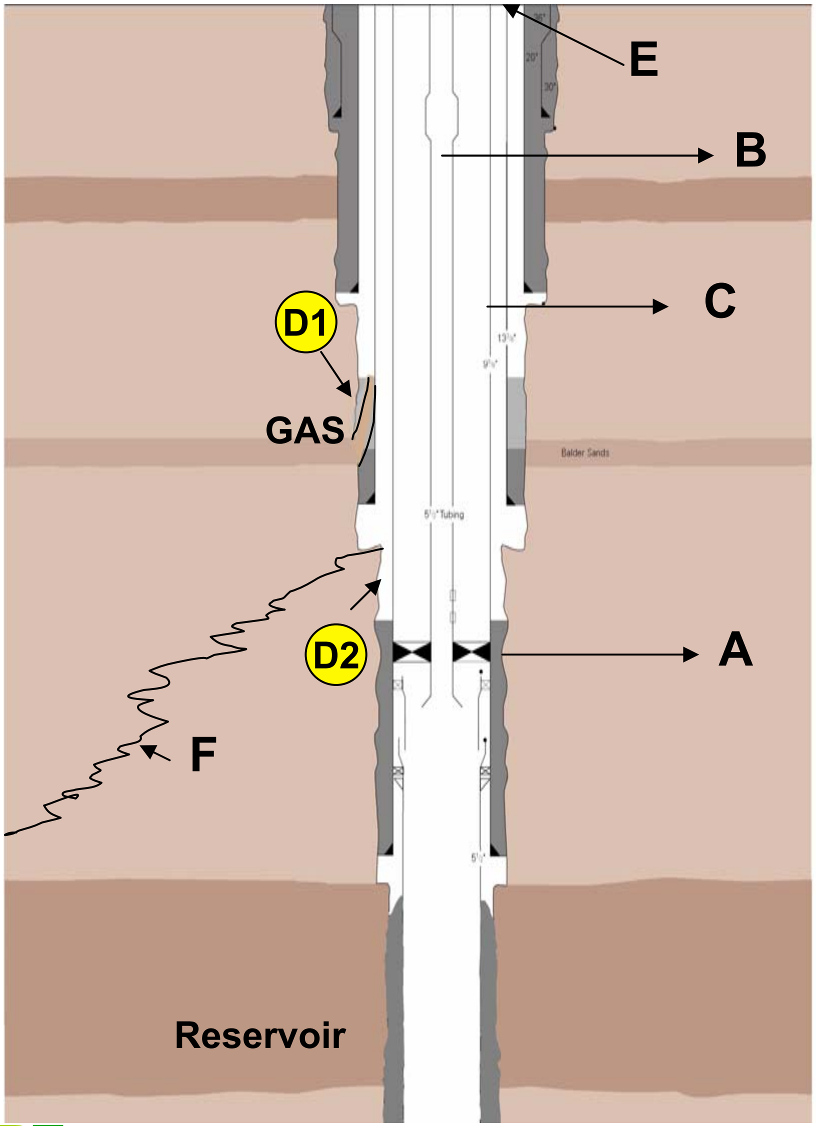
Session 3 – Field Experiences

Daryl Kellingray
Princeton 28 March 2006

Session 3

Session 3. Field Experiences Chair: Daryl Kellingray, BP	
12.00 – 12.30	Introduction/Remediation of Wells with Sustained Casing Pressure Daryl Kellingray, BP
12.30 – 13.30	Lunch
13.30 – 14.00	Advanced Wireline Logging Techniques for Well Integrity Assessment Schlumberger – Yvonnick Vrignaud
14.00 – 14.30	Repairing Wells with Sustained Casing Pressure CSI – Fred Sabins
14.30 – 15.00	Dealing with Wells with Poor Annular Integrity BP – Jo Anders *Teleconference from Alaska*
15.00 – 15.30	Break

Possible Causes of Annular Pressure



A - Production/Injection Packer Leak

B - Tubing Failure

C - Casing Failure

D - Cement

D1 – Channel

D2 – Low top of cement

E - Wellhead Leak

F - Fractures & Faults

What is Sustained Casing Pressure (SCP)

- Occurs in non structural casing strings of wells, it is measurable at the wellhead of the casing annulus. Rebuilding to at least the same pressure when bled down.
- It is not due to temperature or pressure applied from surface to the well.
- Is documented to occur in over 8000 wells in GOM (11,000 casing strings).
- Records indicate four uncontrolled well flows caused by SCP.

SCP on well indicates there is a failing in the pressure envelope of the well.

Implications of SCP for CO_2 Injection

- Escape of the injection fluid outside the tubing possibly resulting in a corrosive environment for production casing
- Connectivity in the formation permitting migration of injection fluids to shallower formation (or into an uncemented annulus).
- Exposure of cement to CO_2 from tubing through casing or via movement in formation

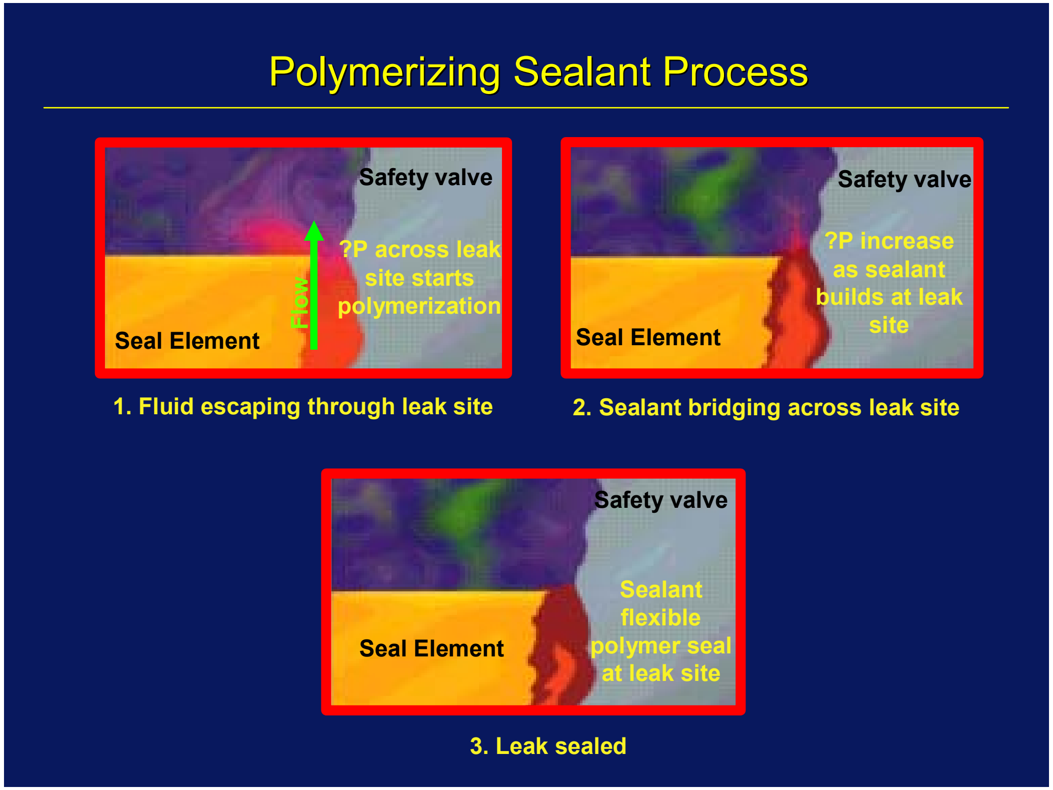
Diagnosis of Sustained Casing Pressure

- **Pressure Testing**
- **Cased Hole Logging**
  - **Temperature Logs (hot spots due to flow from deeper formations)**
  - **Noise Logs (signature of flow behind pipe)**
  - **Injection of tracers (Borax / Radioactive) and subsequent logging of position**
  - **Oxygen activation using pulsed neutron**
  - **Downhole cameras and visualisation tools**
  - **Callipers**

Most cased hole logs are good for tubing but can only assess production casing during a workover when tubing is removed.

Material for remediating SCP - Polymers

- Polymers
  - Acrylic monomer grouts
  - Crosslinked low molecular weight polymers
  - Sealants used for wellheads and pin hole leaks (e.g. Sealtite and Deepseal)

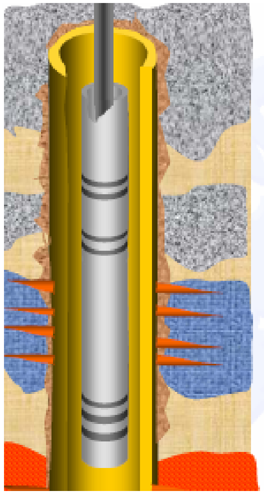


  - Cement polymer combinations

Which are considered long term seals ?

Material for remediating SCP – Other solutions

- **Expandable tubular / patches**

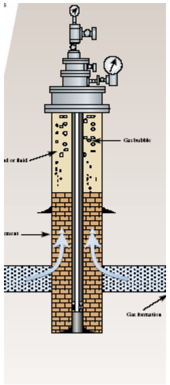


SOLID CASING EXPANSION

- Cased hole remediation system for casing repair, perforation shut-off, corroded casing, ……
- Blank pipes coupled with expandable screens

- **High density viscosified kill fluids (e.g. Calcium Bromide)**

lubricated into the annulus



Product principles

What is Sandaband™

- SAND for ABANDonment
- Sand+Titania disposal Microsilica (to particle gel) Water +Additives, to make a **permanent slurry** without excess water nor segregation
- No pollution
- Patented world wide

- Usages:
  - Abandonment
  - Primary ’cementing’ ”Sandamix”
  - LCM and formation fracture gradient improvement
  - Etc.

- **Others**
  - **Sandaband**
  - **?**

EPT **Would these be acceptable to regulators ?**

Materials for mitigating SCP - Cementitious

- **Hydraulic systems**
  - **OPC/Pozzolanic Cement Blends**
  - **Slag and slag cement blends**
  - **Microsilca / cement blends**
  - **Ultrafine blends**

Cement	Max particle size (microns)	Average particle size (microns)	Fineness (sqcm/g)
Ultrafine systems	15	5	>9000
Class C	50	20	4700
Class G	90	25	3300
Class H	120	30	2200

  - **Non OPC systems (e.g. Phosphates, Ceramicrete)**

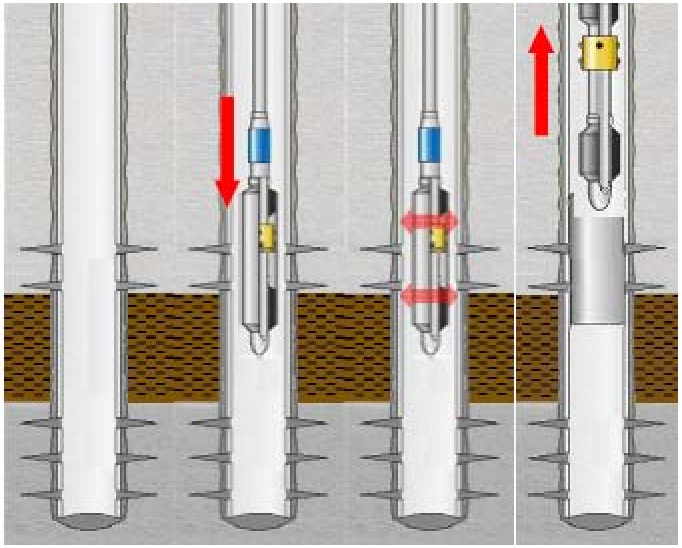
Which of these have long term resistance to exposure to CO_2 ?
What are the mechanical properties at pressure and temperature ?

Deployment – Rig Workover

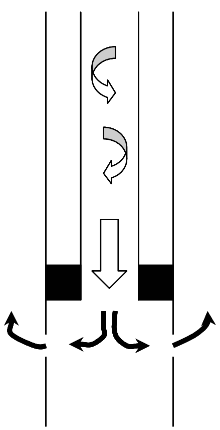
Pull tubing using a rig results in high intervention costs

- Permits replacement of corroded tubing
- Installation of solid expandable liners to repair corroded casing
- Cement squeezes using high and low pressure techniques with a retainer to squeeze off channels behind casing

Solid expandable liner

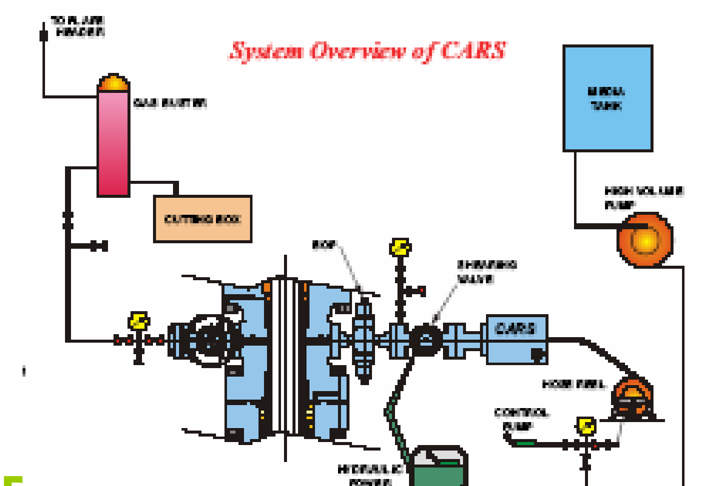


Cement retainer used to apply squeeze pressure to force cement into channels / fractures



Bullheading cement or other treatment directly into the annulus from surface.

- Requires annular injectivty and fracturing of formation
- Could trap pressure beneath previous shoe Risking underground flows



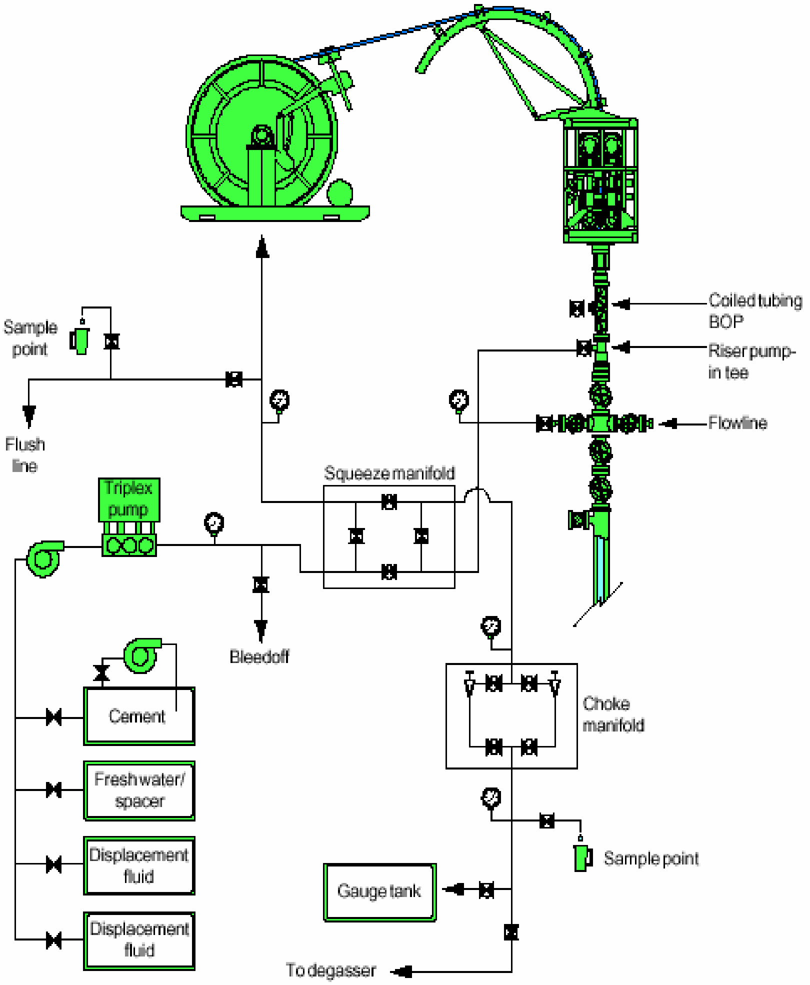
Spotting high density or sealing materials using a Casing Annulus Remediation System (CARS)

- Has limited depth into annulus, may require lubricating heavy fluid in bleeding off light fluid

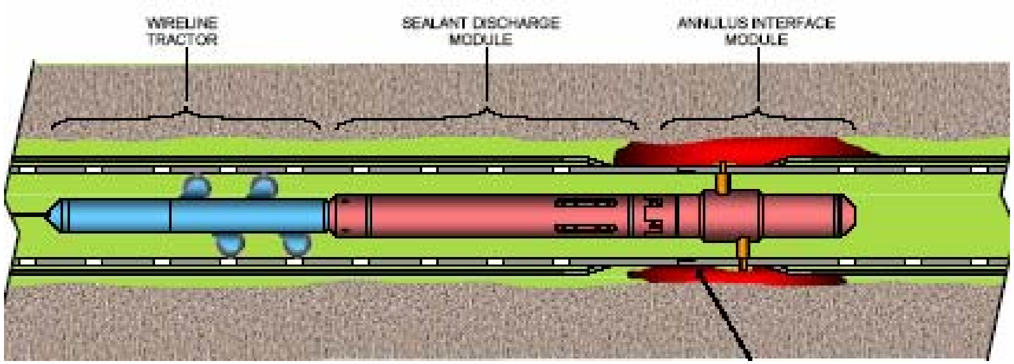
Rig less Intervention

Coiled Tubing

Significantly reduced cost compared to a rig workover, however, limited application to cure sustained casing pressure. Application limited to tubing and production casing annulus.
Can be used to repair poor zonal isolation as a consequence of poor reservoir isolation.



Wireline deployable remedial annulus packers



Application in large annuli ?

Conclusions

- Incidence of wells with poor integrity is high
- Many possible causes, diagnosis not always easy or low cost
- Many options available for remediation but uncertainty about durability of the approach and resistance to $CO_{2.}$
- In some areas annular bullheads not permitted
- Problems with casing integrity may involve a full workover with significant cost ($>100K per well onshore)
- Subsequent presentations to examine some of the options and well experiences.

Advanced wireline logging techniques for well integrity assessment

Yvonnick Vrignaud

Well Integrity Product Champion – Wireline – Clamart, France

Schlumberger

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Outline

Isolation assessment

- Sonic CBL-VDL and attenuation
- Pulse-echoe technique
- Scanning of the annulus material

Piping assessment

- Mechanical
- Ultrasonic
- Electromagnetic Flux leakage and Remote-field eddy currents

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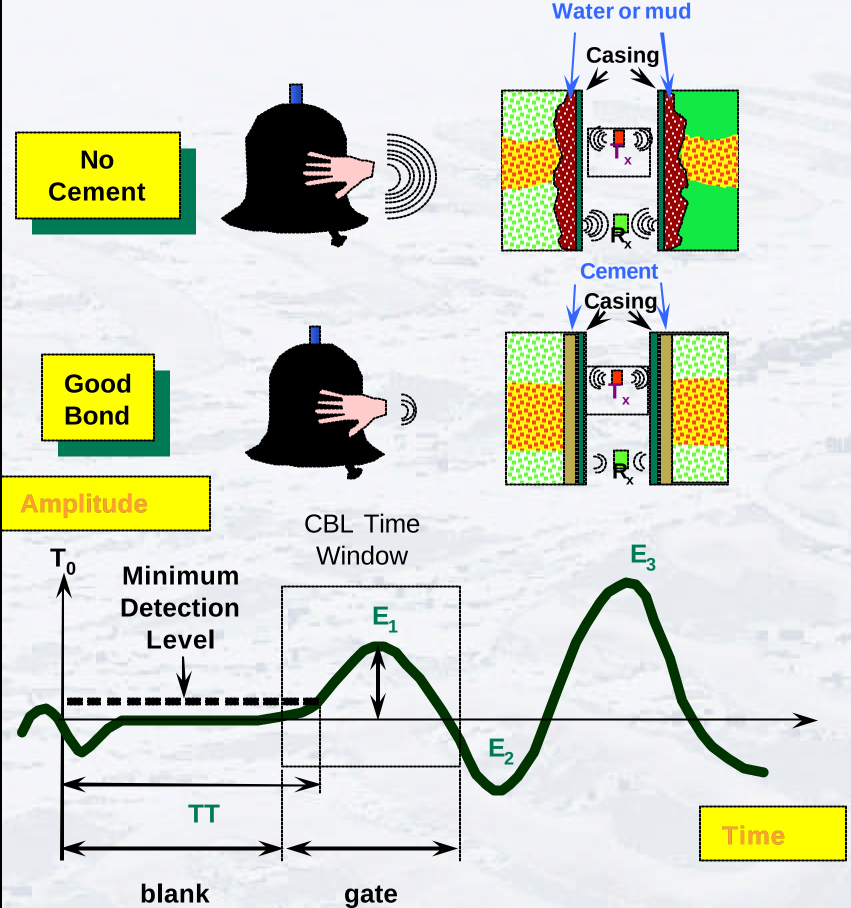
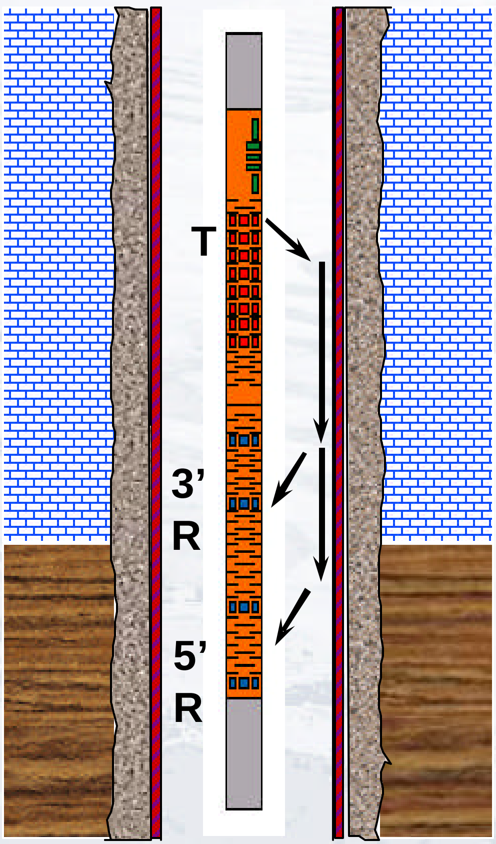
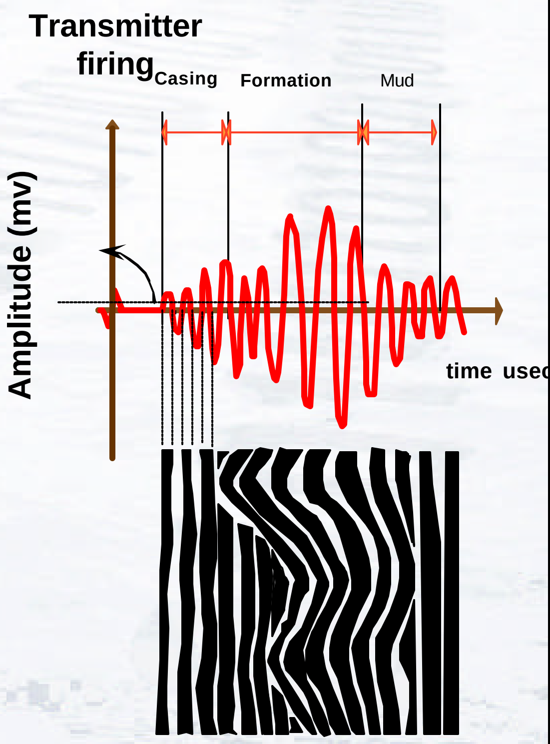
Sonic Omnidirectional evaluation







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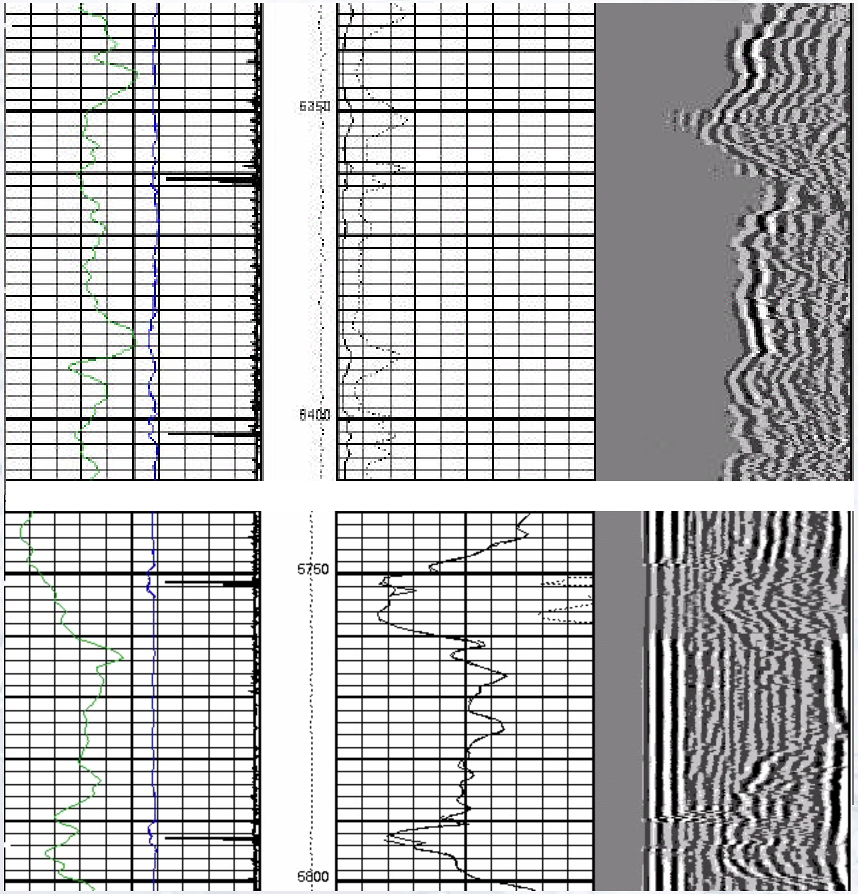
CBL-VDL Applications

Strengths

- Work well in most well fluids, tolerate corrosion
- Respond to solidity (shear coupling)
- Qualitative cement-formation bond from VDL
- Mapping tools identify broad channels

Weaknesses

- High CBL amplitude can be ambiguous
- liquid microannulus (shear coupling lost)
- Channels of contaminated cement and/or light cement
- Sensitive to Fast formation
- Extremely sensitive to eccentering



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Sonic attenuation

Strengths vs. Amplitude measurements

- Insensitive to Fluid changes
- Less sensitive to eccentering
- 1ft measurement insensitive to fast formation

Operating

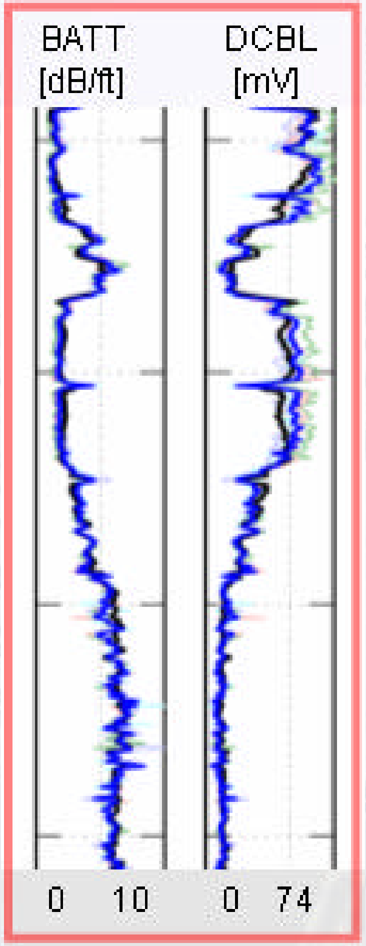
- Must have fluid in the well
- Plan for pass with & without pressure (if micro annulus suspected)
- Need to know cement characteristics

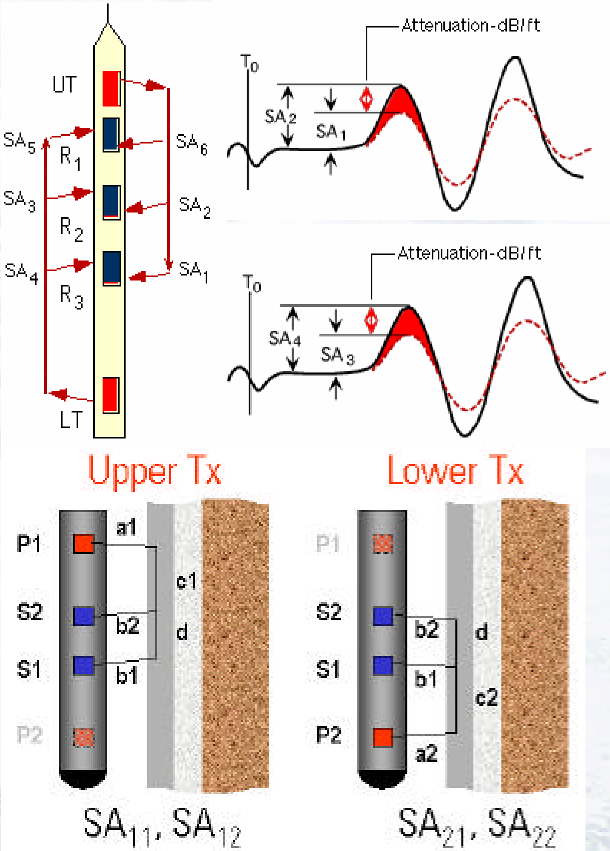
Strengths vs advanced evaluation tools:

- Dry micro-annulus
- Relative insensitivity to casing damage/corrosion
- Qualitative VDL for formation to annulus bond

Weaknesses :

- Channeling
- Wet microannulus





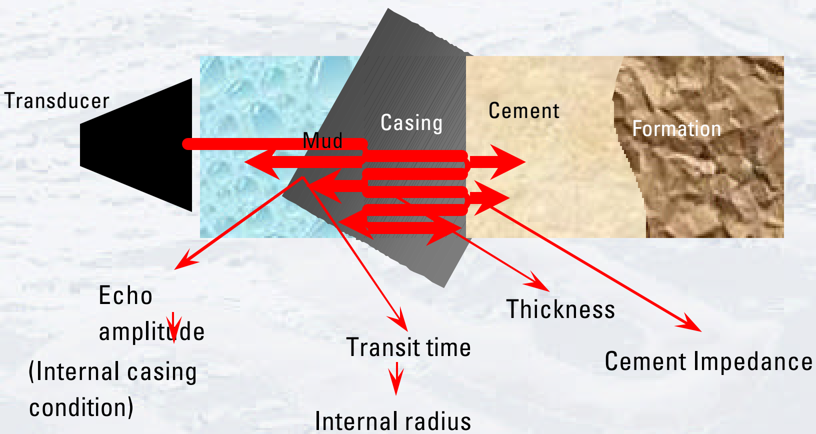
$$BATT = \log_{10}\left[\frac{SA_{11} SA_{22}}{SA_{21} SA_{12}}\right] / 2 / d$$

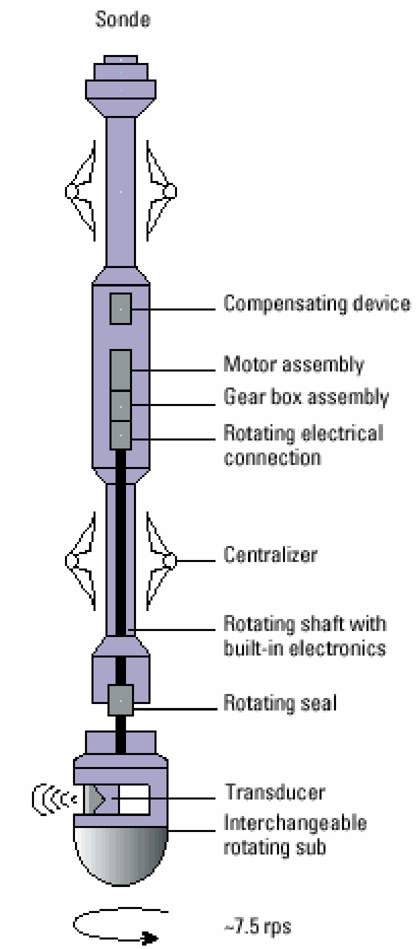
Pulse-echoe evaluation

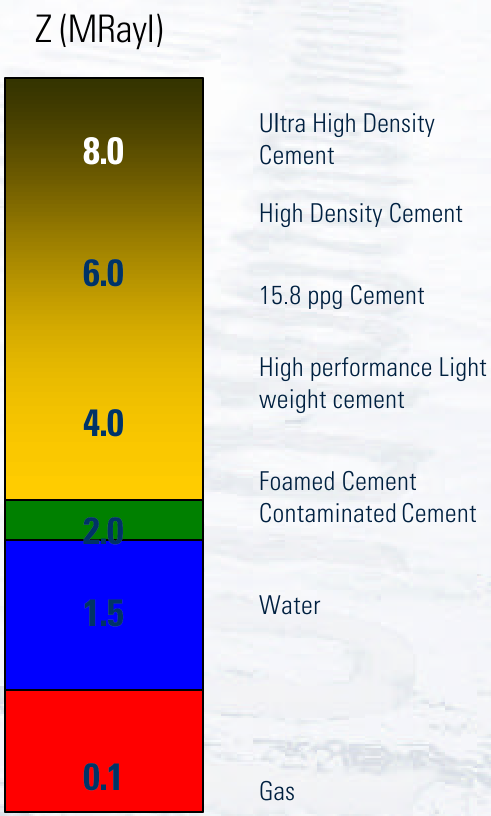
To provide azimuthal cement evaluation

- Ultrasonic tool operating between 200 and 700 kHz.
- Full casing coverage at 1.2 in. (30 mm) resolution
- using rotating transducer

Measuring the acoustic impedance (Z) of the material in the annulus by sending an ultrasonic pulse and measuring the decay of the reflections using a single rotating transducer. [$Z = \rho \times V_p$]







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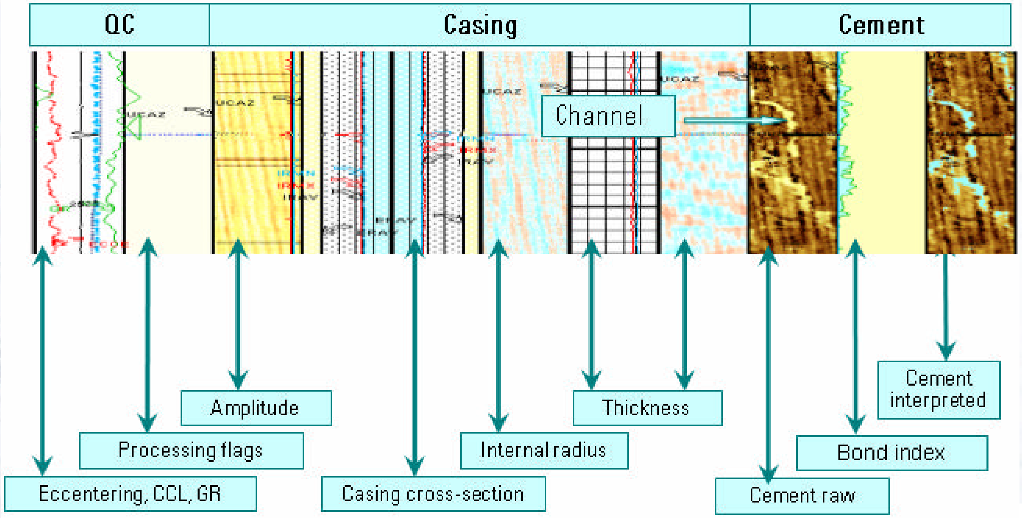
Pulse echoe Applications

	Pulse-Echoe	CBL/VDL
Resolution	5 -10 deg. x 1.2 in.	360 deg. x 3 ft
Well bonded cement	Cement	Cement
Very light cement	Low contrast [special processing if debonded]	Low contrast from mud
Dry microann. Debonded cement	Dry microann. /gas (special processing)	Good/fair bond
Wet microann.	Slightly affected	Ambiguous (pressure)
Mud layer	Channel	Ambiguous
Contaminated cement	Low-Z cement	Ambiguous
Mixed lead/tail cement	Mixed Z (lead/tail)	Ambiguous
Mud channel	Channel	Ambiguous
Gas channel	Gas channel	Cement/ambiguous
Formation bond	Not seen	VDL qualitative
Outer casing/ fast formation	Slightly affected	Strongly affected
Casing condition	Very sensitive	Slightly sensitive
Mud attenuation	< 12 dB/cm/MHZ	No limit



Strengths

- Identifies channels (directional)
- Include Pipe wear information

Weaknesses

- Requires continuous fluid medium
- Sensitive to dry microannulus
- Reacts to immediate vicinity of casing outer diameter

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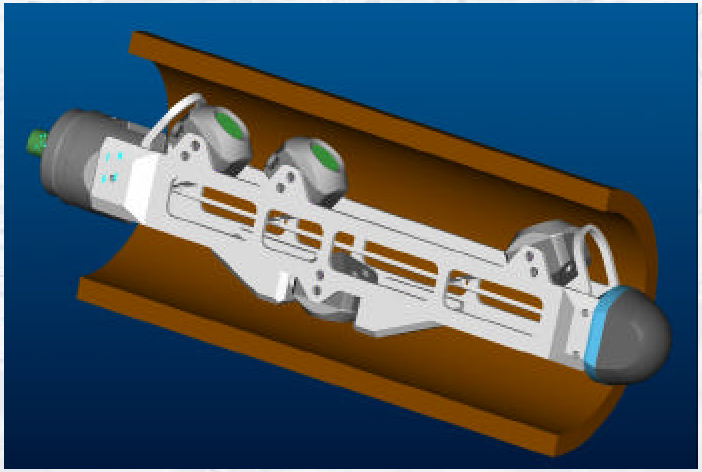
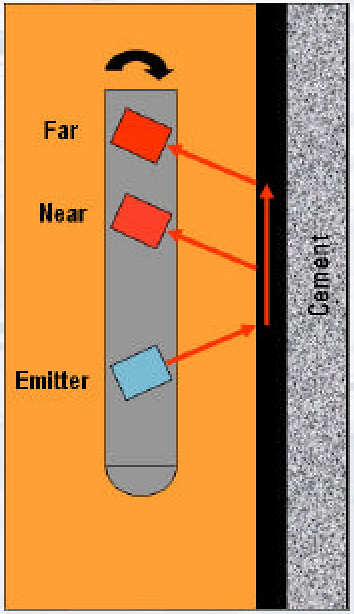
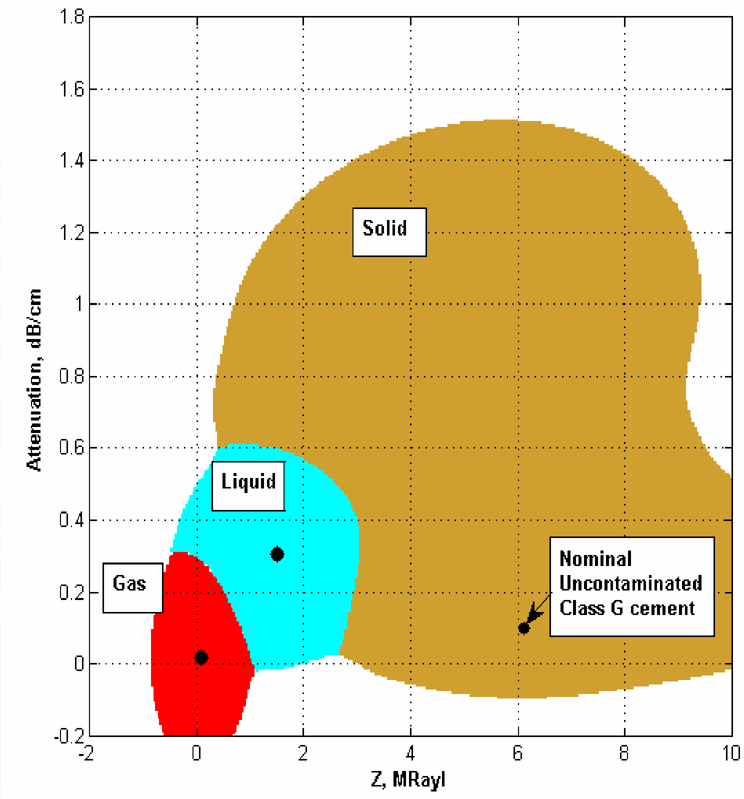
Annulus Scanning

Combines Pulse-echoe measurement with flexural attenuation in casing to have :

- Improved evaluation of lightweight and contaminated cements
- Casing centralization imaging







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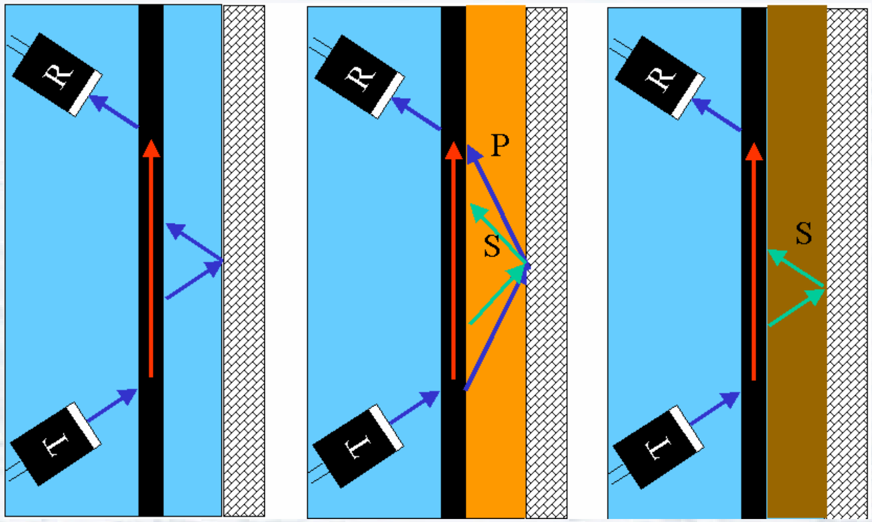
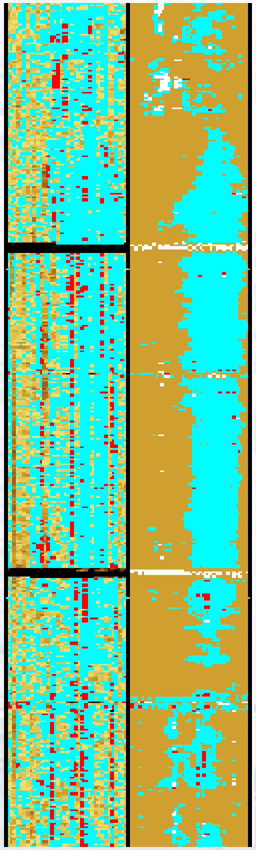
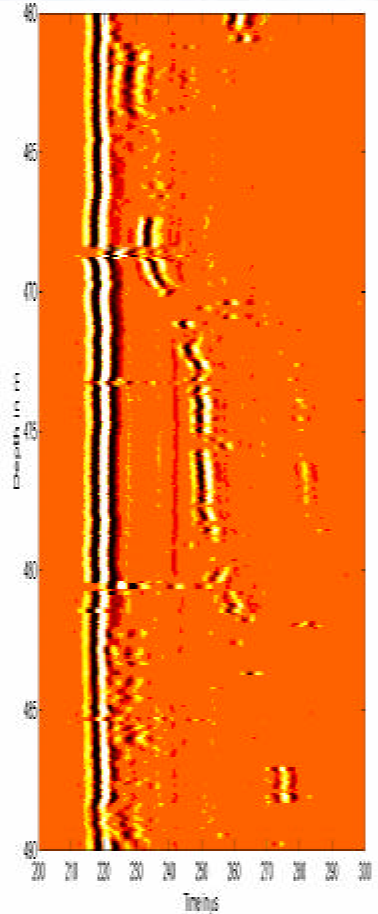
Annulus width imaging





0–360 ° AI **0–360 ° SLG**

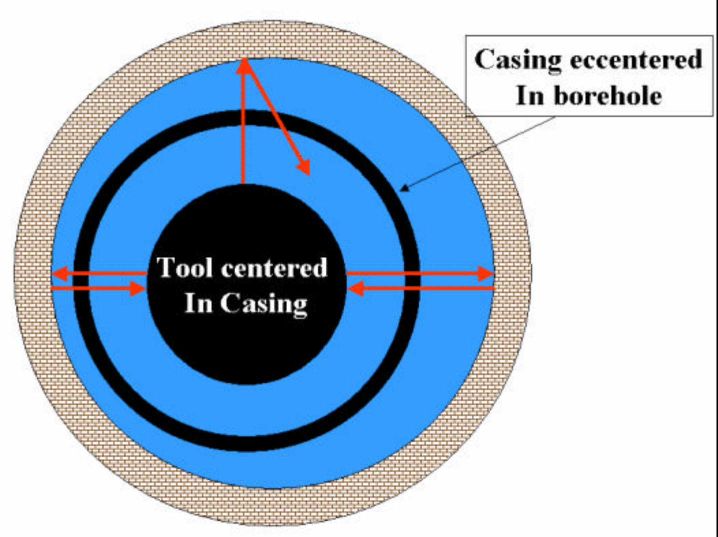


Far receiver VDL, azimuth 270 °

Analysis of flexural waveforms can:

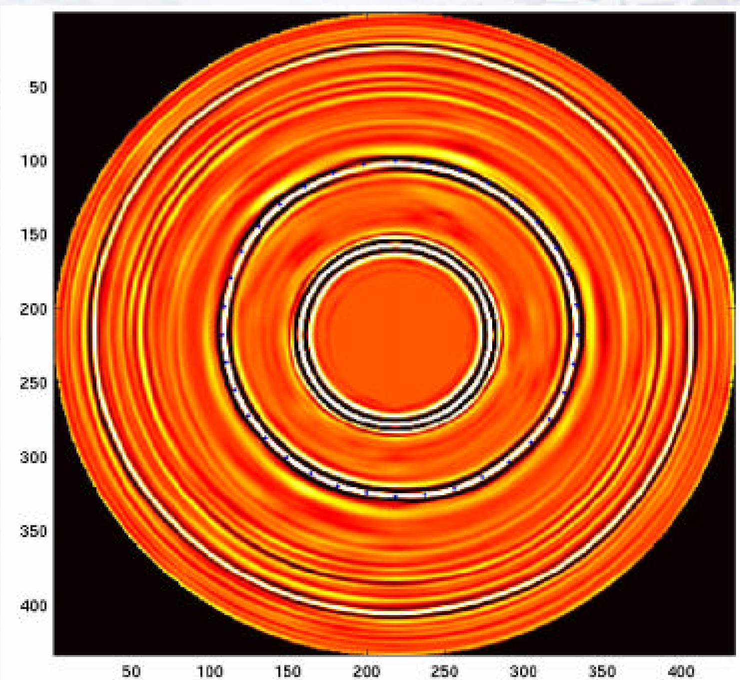
- Provide estimate of geometry or
- Cement velocities [Vp , Vs]

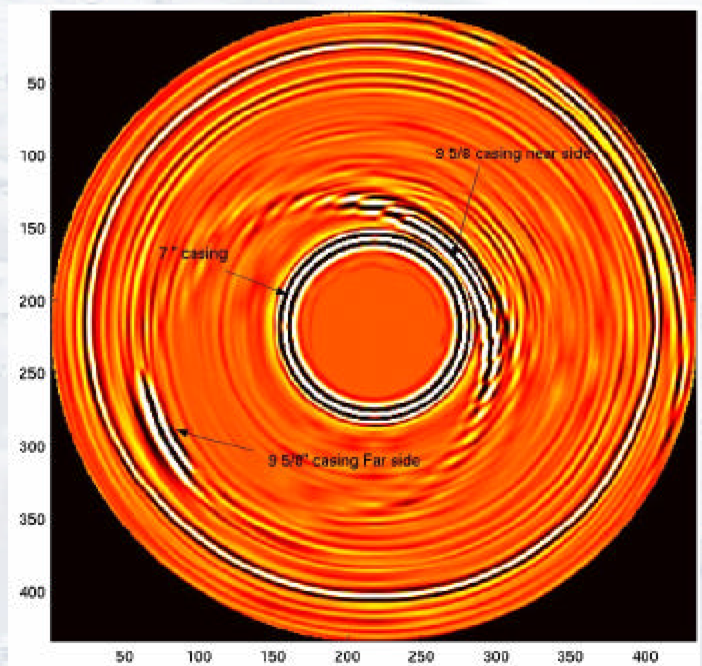
Limitations



Echo amplitudes affected by many factors outside the casing, including

- Casing centering
- Cement attenuation
- Formation contrast
- Formation roughness





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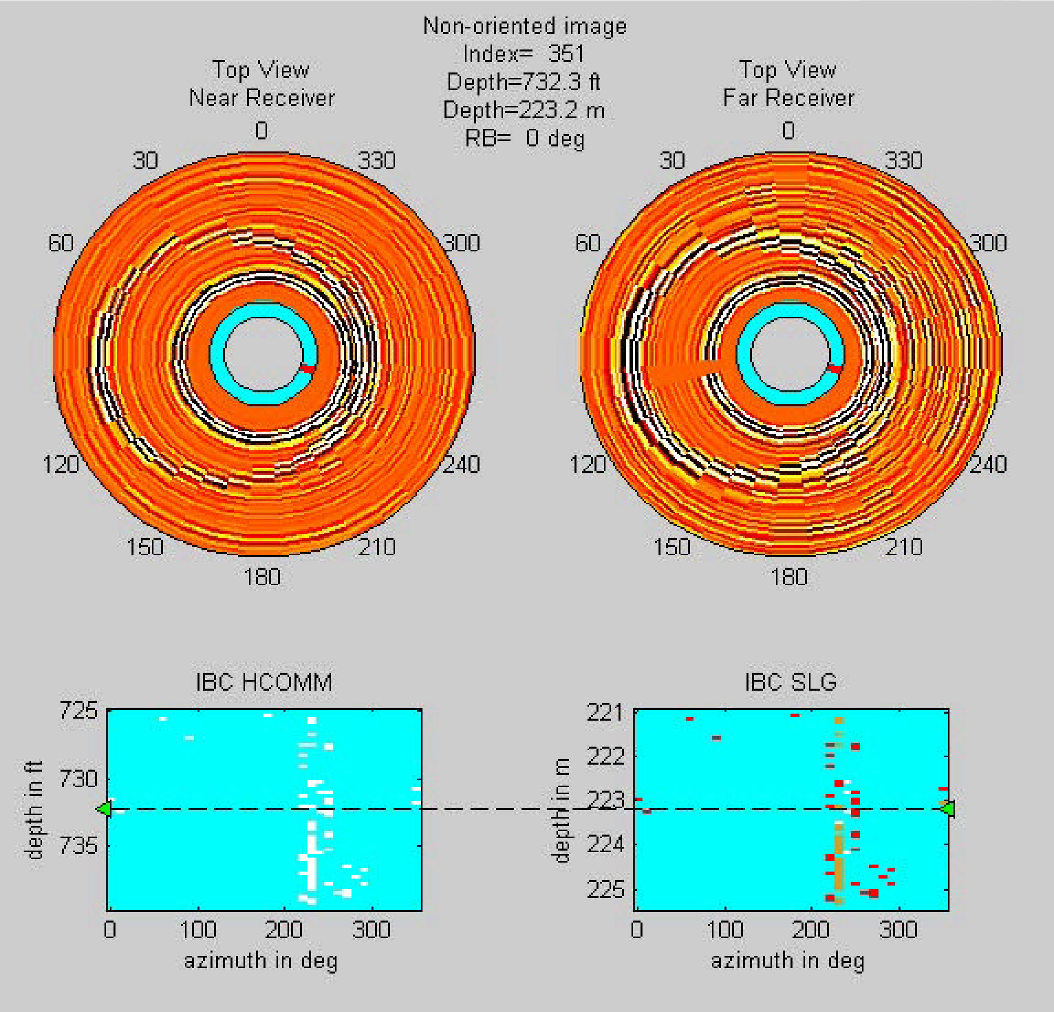
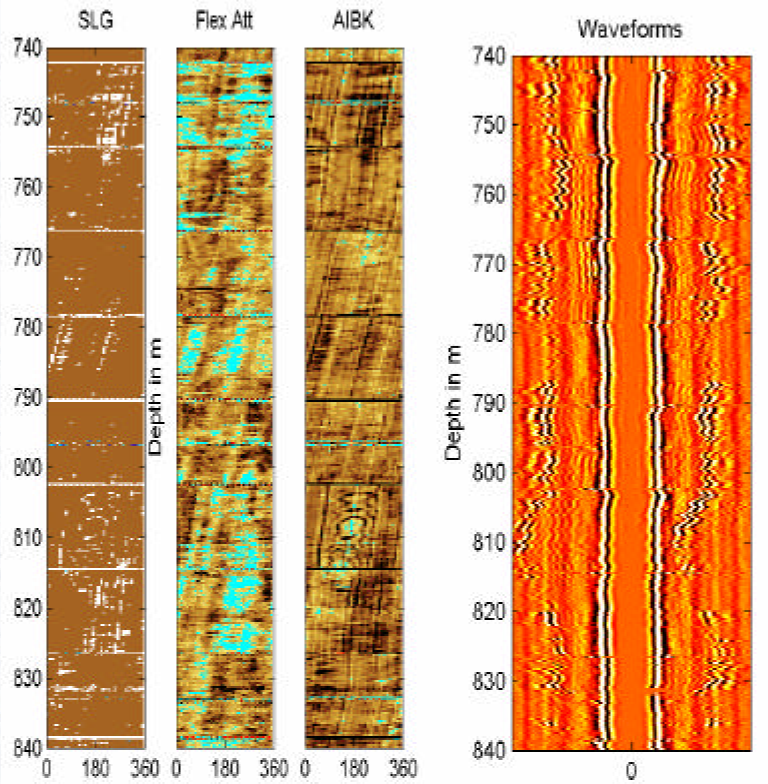
Casing Centralization

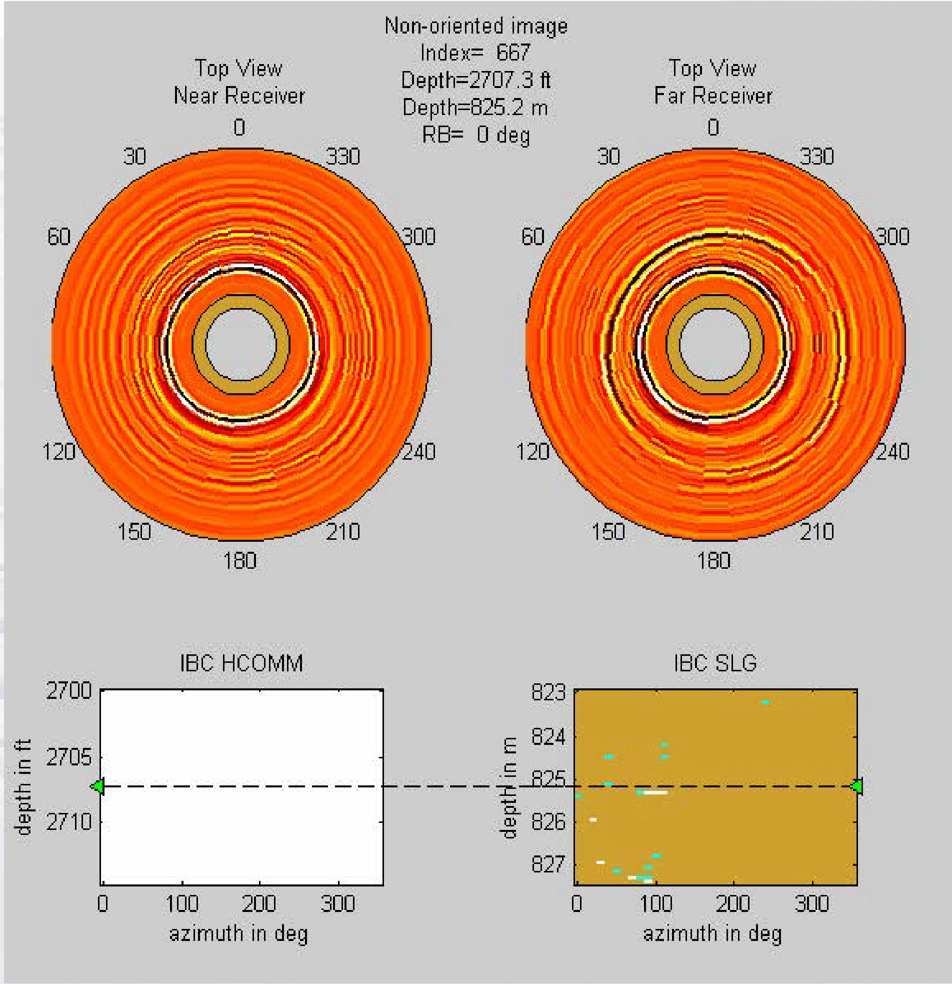
Double string of free pipe



Cement Sheath

Corkscrew hole behind Class G cement





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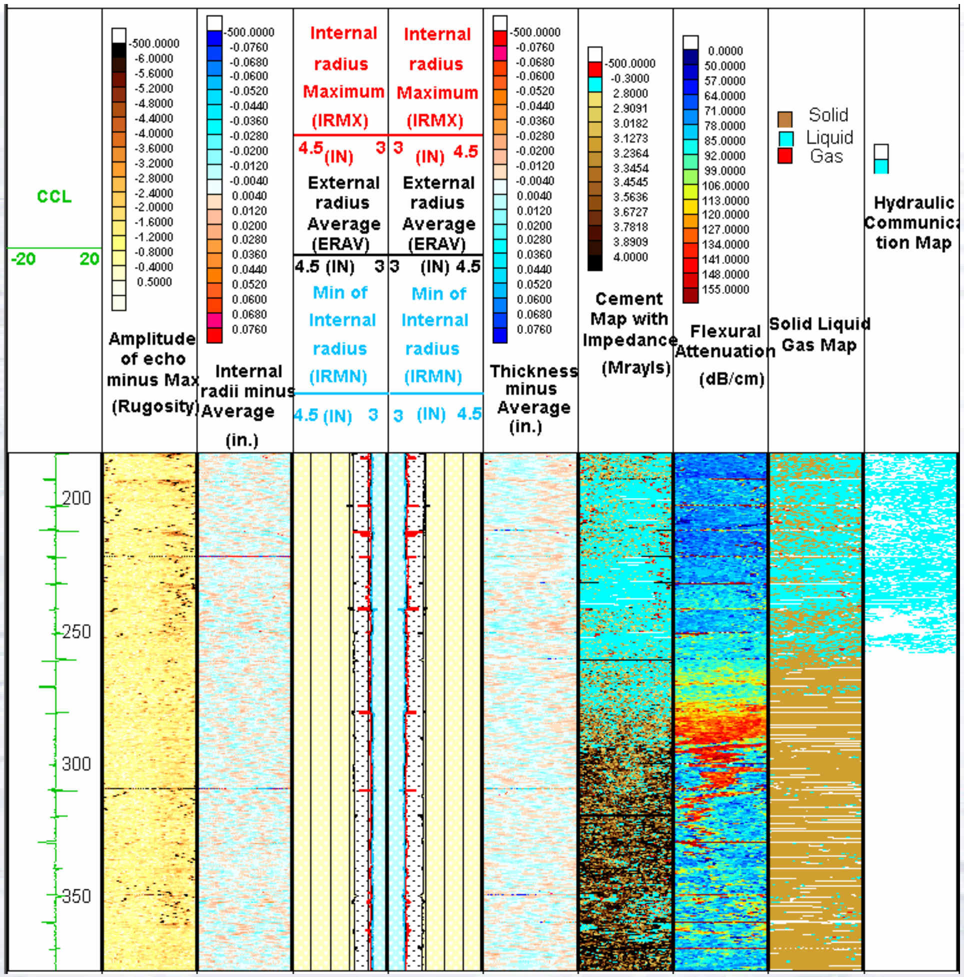
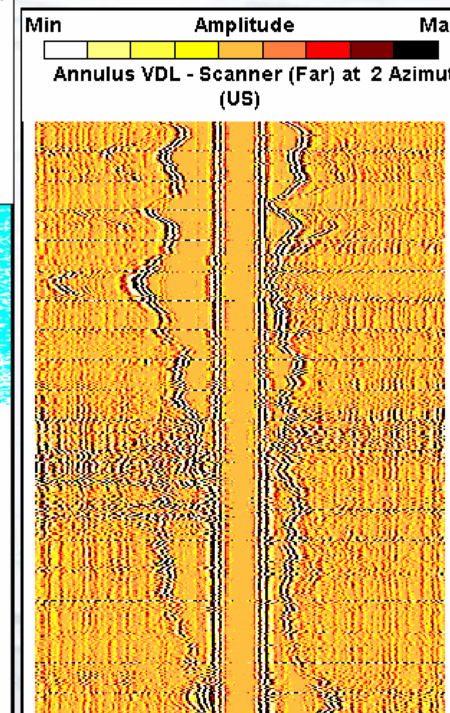
Applications

Ability to observe degradation of cement thickness, properties vs time

[Z , Vp,Vs…]

3D display





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Mechanical evaluation of corrosion

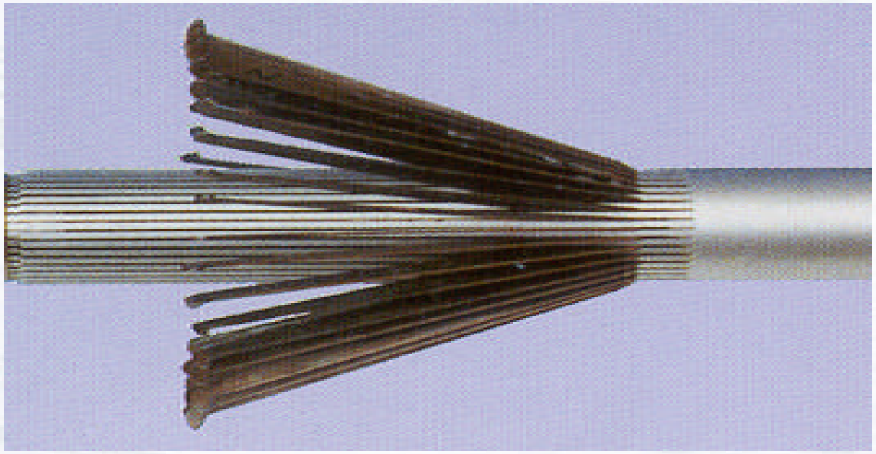
Individual Caliper Movements are converted to voltages that are calibrated to give independent radius reading.

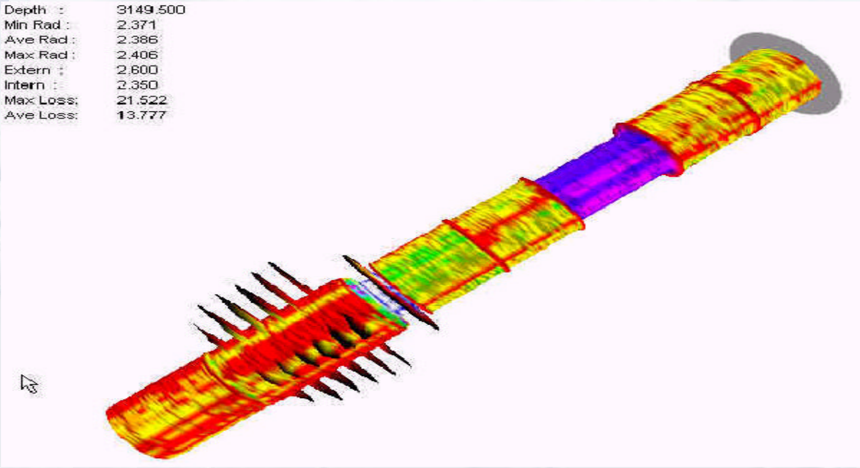
Strengths:

- High accuracy
- Ease of deployment
- High radial resolution
- Wide range of tool ratings available
- All media possible

Weaknesses:

- Limited coverage
- Only internal corrosion
- Scale sensitive
- Not imager of pin-holes





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Ultrasonic evaluation of corrosion

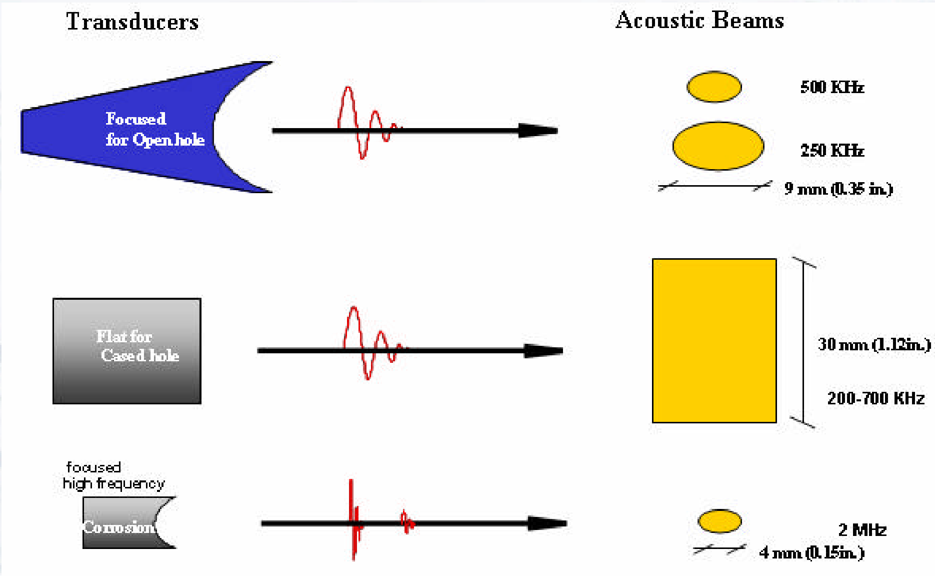
Different transducers have a different focus and resolution

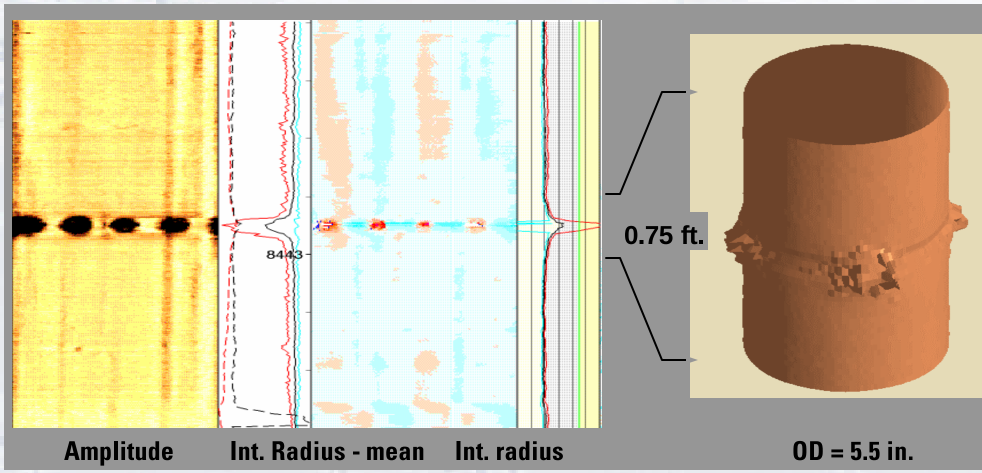
Strengths:

- Ideal for wear measurements
- Can be used for metal loss and holes/pits
- Accuracy
- 100% coverage
- Internal & external corrosion

Weaknesses:

- Requires fluid
- Single casing/piping
- Can be limited by internal scale build-up





Electromagnetic evaluation of corrosion

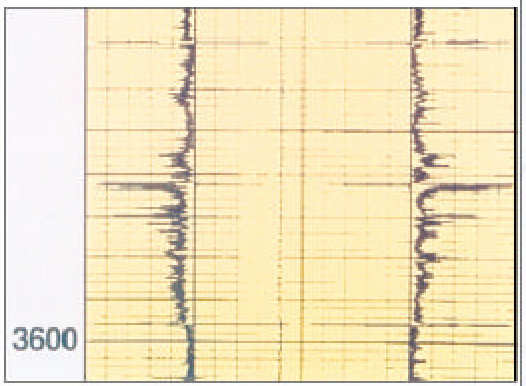
<u>Flux leakage techniques</u> rely on variations of Magnetic flux:

Strengths:

- Best suited to detect pitting, corrosion patches and holes
- Any fluid/gas

Weaknesses:

- Insensitive to gradual casing wear = Do not allow corrosion rates to be derived



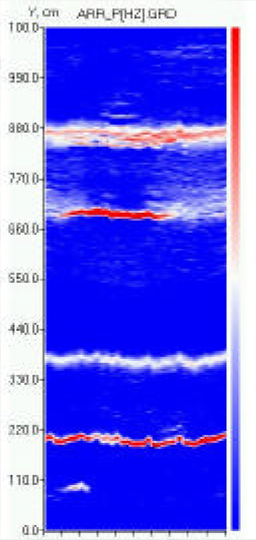
<u>Remote field eddy current</u> techniques rely on proportionality between remote field phase shift and metal thickness/magnetic permeability/conductivity

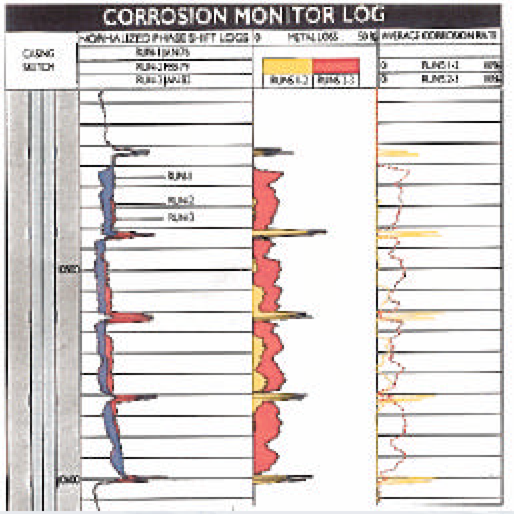
Strengths:

- Multiple casing strings
- Any fluid/gas
- Best suited for large-scale corrosion, large holes and vertical splits
- Insensitive to most scales [non magnetic, non conductive]
- Can be corrected for magnetic permeability variations

Weakness:

- Will not detect extremely small holes





Comments ?

Discussion topics possible :

- Planned experiments with large time scale
- Specific needs for the CO_2 storage facilities for techniques/monitoring of the well integrity
- Strengths and weaknesses of each technology in use

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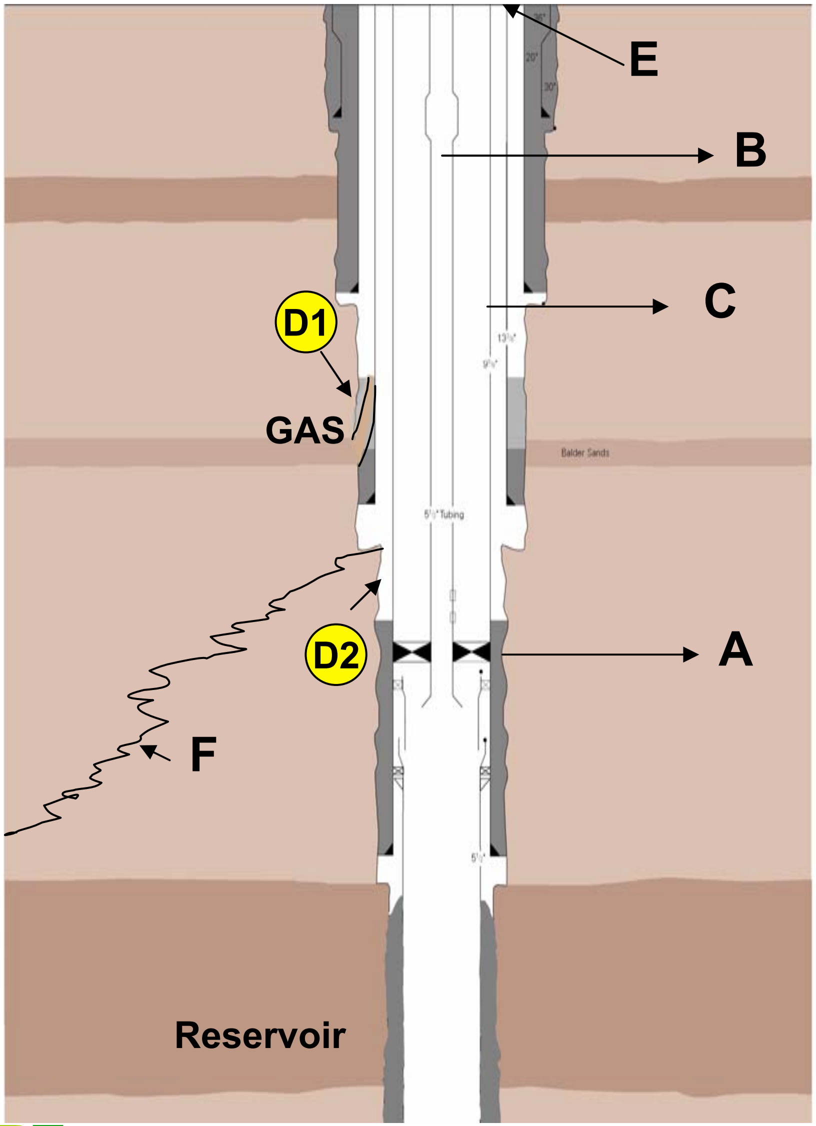
Session 3

Session 3. Field Experiences Chair: Daryl Kellingray, BP	
12.00 – 12.30	Introduction/Remediation of Wells with Sustained Casing Pressure Daryl Kellingray, BP
12.30 – 13.30	Lunch
13.30 – 14.00	Advanced Wireline Logging Techniques for Well Integrity Assessment Schlumberger – Yvonnick Vrignaud
14.00 – 14.30	Repairing Wells with Sustained Casing Pressure CSI – Fred Sabins
14.30 – 15.00	Dealing with Wells with Poor Annular Integrity BP – Jo Anders *Teleconference from Alaska*
15.00 – 15.30	Break

Possible Causes of Annular Pressure



A - Production/Injection Packer Leak

B - Tubing Failure

C - Casing Failure

D - Cement

D1 – Channel

D2 – Low top of cement

E - Wellhead Leak

F - Fractures & Faults

What is Sustained Casing Pressure (SCP)

- Occurs in non structural casing strings of wells, it is measurable at the wellhead of the casing annulus. Rebuilding to at least the same pressure when bled down.
- It is not due to temperature or pressure applied from surface to the well.
- Is documented to occur in over 8000 wells in GOM (11,000 casing strings).
- Records indicate four uncontrolled well flows caused by SCP.

SCP on well indicates there is a failing in the pressure envelope of the well.

Implications of SCP for CO_2 Injection

- Escape of the injection fluid outside the tubing possibly resulting in a corrosive environment for production casing
- Connectivity in the formation permitting migration of injection fluids to shallower formation (or into an uncemented annulus).
- Exposure of cement to CO_2 from tubing through casing or via movement in formation

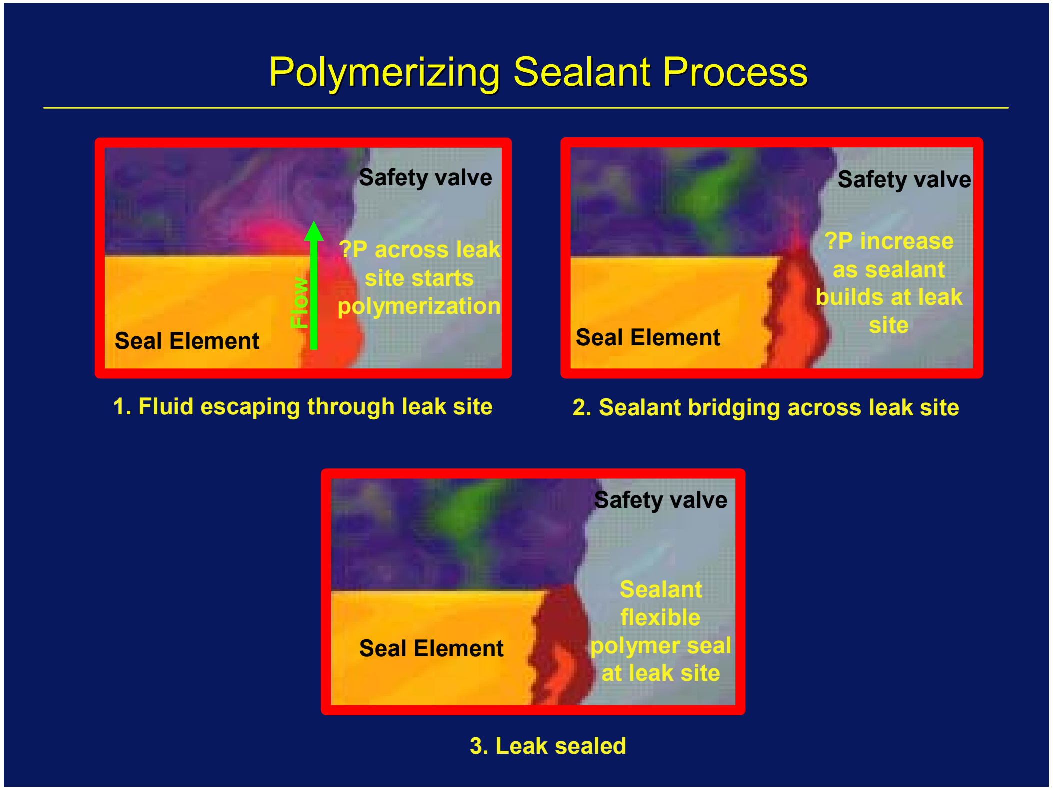
Diagnosis of Sustained Casing Pressure

- **Pressure Testing**
- **Cased Hole Logging**
  - **Temperature Logs (hot spots due to flow from deeper formations)**
  - **Noise Logs (signature of flow behind pipe)**
  - **Injection of tracers (Borax / Radioactive) and subsequent logging of position**
  - **Oxygen activation using pulsed neutron**
  - **Downhole cameras and visualisation tools**
  - **Callipers**

Most cased hole logs are good for tubing but can only assess production casing during a workover when tubing is removed.

Material for remediating SCP - Polymers

- Polymers
  - Acrylic monomer grouts
  - Crosslinked low molecular weight polymers
  - Sealants used for wellheads and pin hole leaks (e.g. Sealtite and Deepseal)

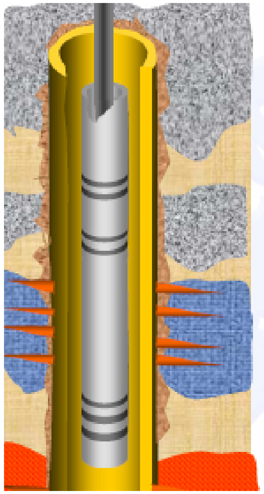


  - Cement polymer combinations

Which are considered long term seals ?

Material for remediating SCP – Other solutions

- **Expandable tubular / patches**

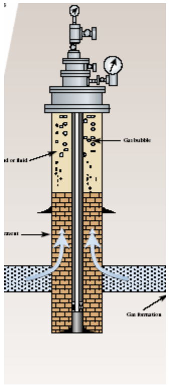


SOLID CASING EXPANSION

- Cased hole remediation system for casing repair, perforation shut-off, corroded casing, ...
- Blank pipes coupled with expandable screens

- **High density viscosified kill fluids (e.g. Calcium Bromide)**

  lubricated into the annulus



- **Others**
  - **Sandaband**
  - **?**

Product principles

What is Sandaband™

- SAND for ABANDonment
- Sand+Titania disposal Microsilica (to particle gel) Water +Additives, to make a **permanent slurry** without excess water nor segregation
- No pollution
- Patented world wide

- Usages:
  - Abandonment
  - Primary ’cementing’ ”Sandamix”
  - LCM and formation fracture gradient improvement
  - Etc.

EPT **Would these be acceptable to regulators ?**

Materials for mitigating SCP - Cementitious

- **Hydraulic systems**
  - **OPC/Pozzolanic Cement Blends**
  - **Slag and slag cement blends**
  - **Microsilca / cement blends**
  - **Ultrafine blends**

Cement	Max particle size (microns)	Average particle size (microns)	Fineness (sqcm/g)
Ultrafine systems	15	5	>9000
Class C	50	20	4700
Class G	90	25	3300
Class H	120	30	2200

  - **Non OPC systems (e.g. Phosphates, Ceramicrete)**

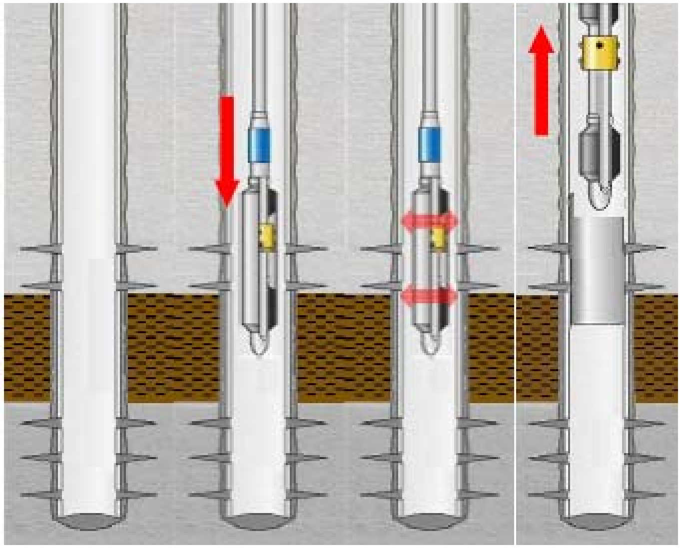
Which of these have long term resistance to exposure to CO_2 ?
What are the mechanical properties at pressure and temperature ?

Deployment – Rig Workover

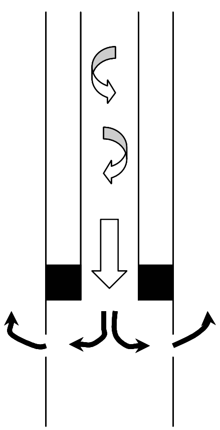
Pull tubing using a rig results in high intervention costs

- **Permits replacement of corroded tubing**
- **Installation of solid expandable liners to repair corroded casing**
- **Cement squeezes using high and low pressure techniques with a retainer to squeeze off channels behind casing**

Solid expandable liner



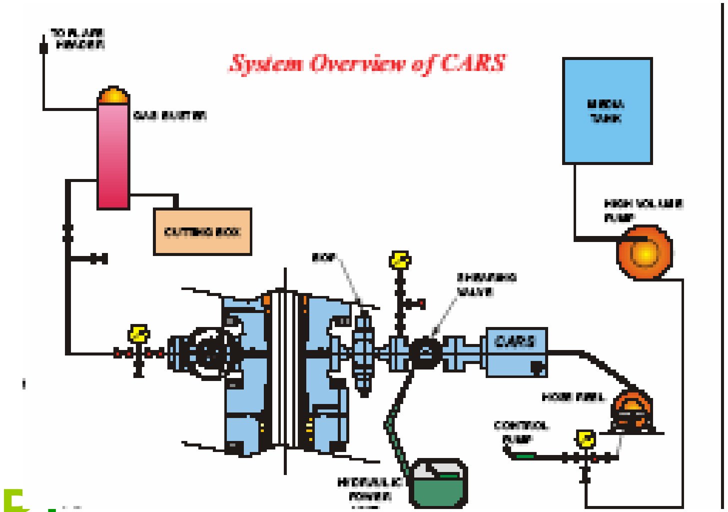
Cement retainer used to apply squeeze pressure to force cement into channels / fractures



Annular Bullheading

Bullheading cement or other treatment directly into the annulus from surface.

- Requires annular injectivty and fracturing of formation
- Could trap pressure beneath previous shoe Risking underground flows



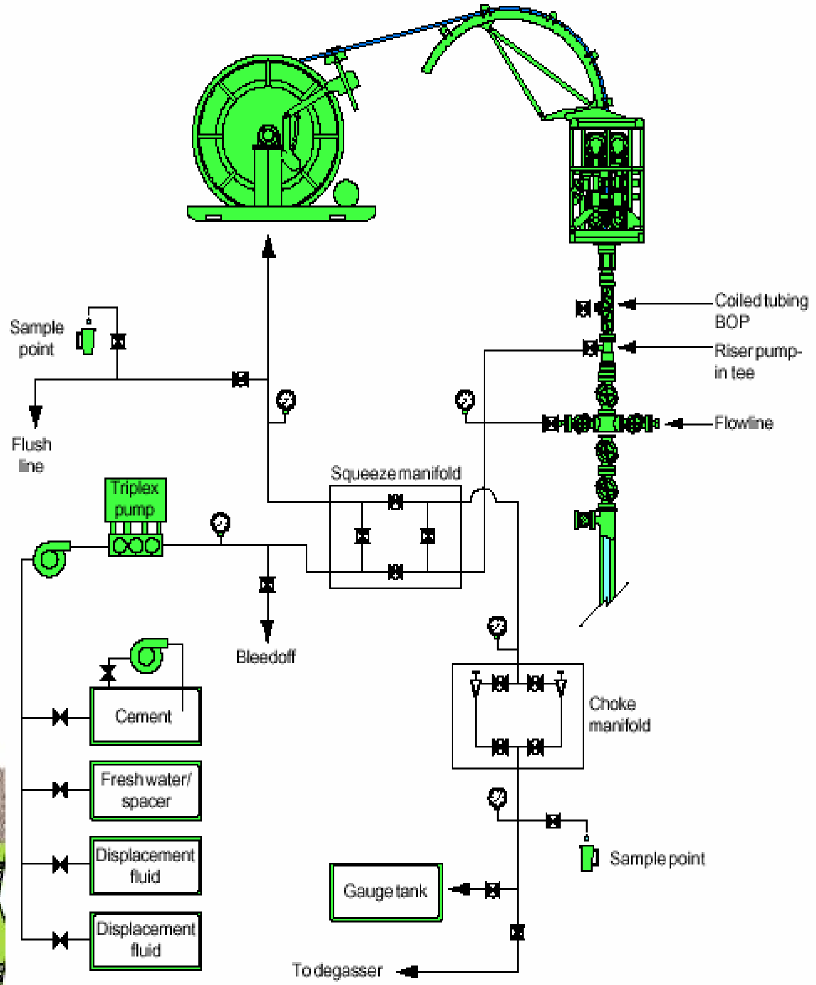
Spotting high density or sealing materials using a Casing Annulus Remediation System (CARS)

- Has limited depth into annulus, may require lubricating heavy fluid in bleeding off light fluid

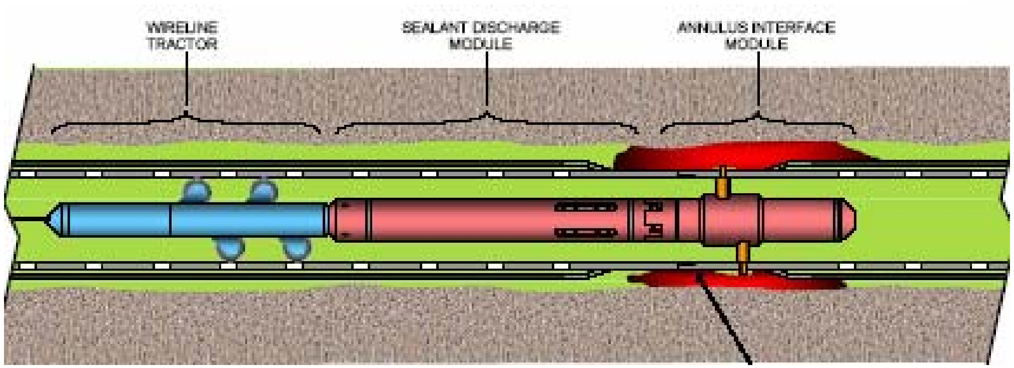
Rig less Intervention

Coiled Tubing

Significantly reduced cost compared to a rig workover, however, limited application to cure sustained casing pressure. Application limited to tubing and production casing annulus.
Can be used to repair poor zonal isolation as a consequence of poor reservoir isolation.



Wireline deployable remedial annulus packers



Application in large annuli ?

Conclusions

- Incidence of wells with poor integrity is high
- Many possible causes, diagnosis not always easy or low cost
- Many options available for remediation but uncertainty about durability of the approach and resistance to $CO_{2.}$
- In some areas annular bullheads not permitted
- Problems with casing integrity may involve a full workover with significant cost ($>100K per well onshore)
- Subsequent presentations to examine some of the options and well experiences.

Repairing Wells with Sustained Casing Pressure

Fred Sabins

CSI Technologies

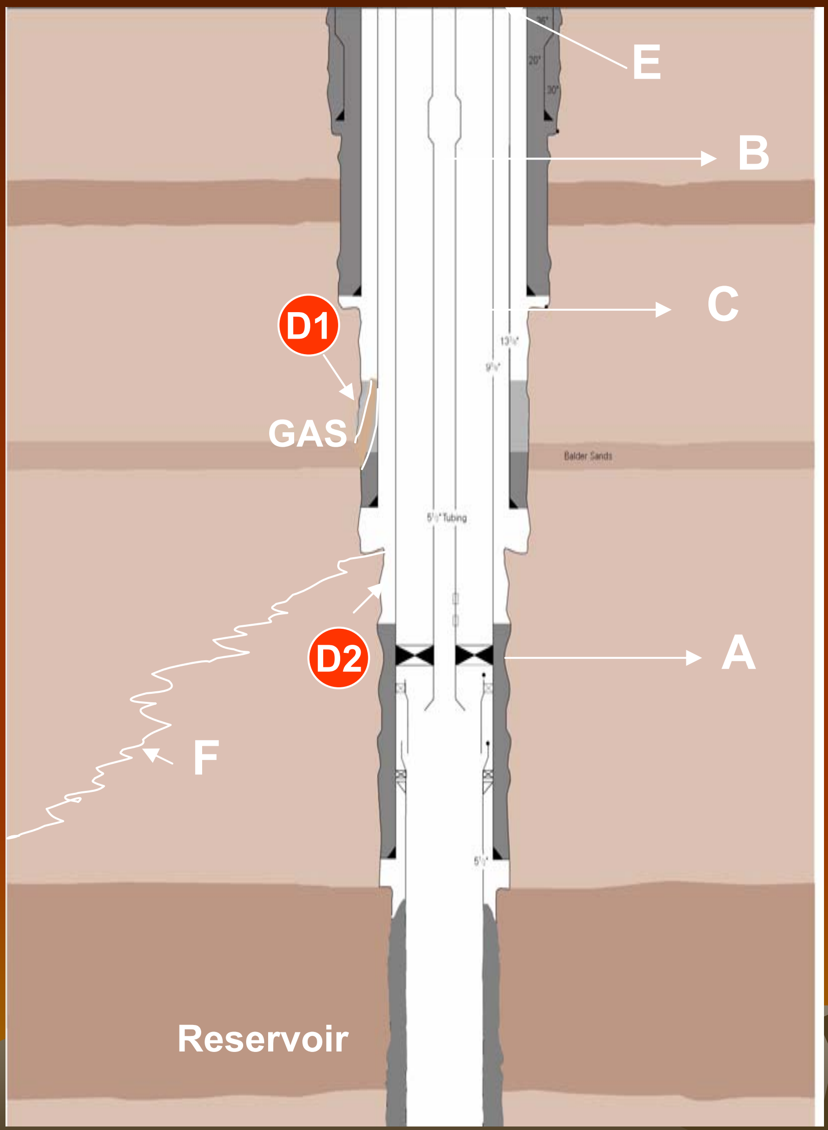
Discussion

- State of Industry today
- Root Cause
- Identification and Location
- Materials
- Placement and special tools

Industry/CSI

- MMS regulations
  - Producing wells
  - Abandoning wells
- Research projects
  - Ability of cements to prevent SCP
  - Well conditions that contribute to SCP
- New Material development
- Designing and support of field jobs for SCP

Possible Causes of Annular Pressure



A - Production/Injection Packer Leak

B - Tubing Failure

C - Casing Failure

D - Cement

D1 – Channel

D2 – Low top of cement

E - Wellhead Leak

F - Fractures & Faults

Cement Sheath Failure

- Stresses in wellbore
  - Pressure test of casing
  - Interventions
  - Thermal cycling
- Cements can deform with stresses
  - Repeated cycling
  - Magnitude of stresses
  - Condition in well – restraint
- Low Density Cements/Surface Pipes

Materials for SCP

- Non setting weighted systems – no experience
- Sealants (low solids)
  - Polymer systems
  - Gel Systems
  - Resins
- Microfine cement systems
- Drilling requirements

Techniques

- Perf and squeeze
- Squeeze down back side
  - Bull head
  - Small string
- Pump and fall
- Mill and balanced plug
- Dump bailer
- Coiled tubing- Controlled Volume

Seal Tite

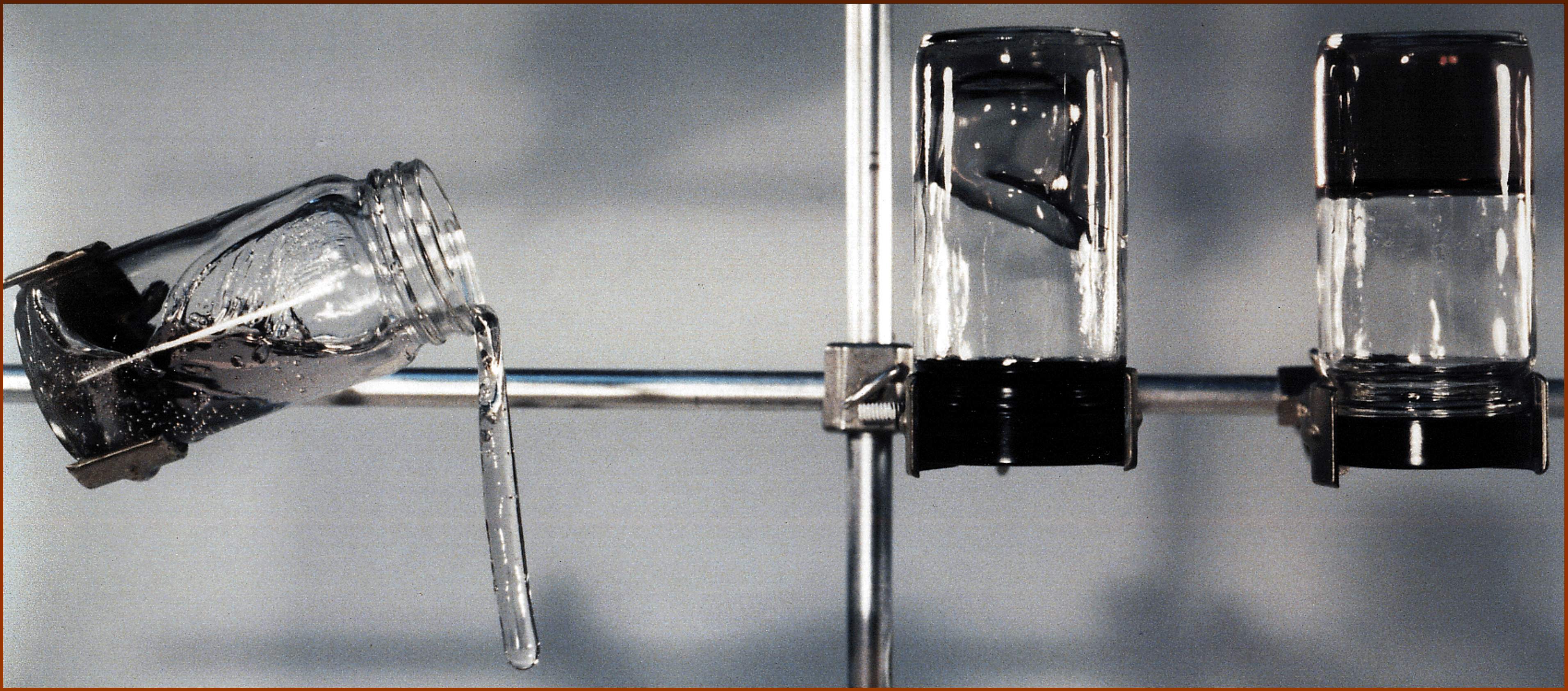
- Crosslinking Polymer
- Requires injection
- Requires differential pressure/shear
- Deformable polymeric material

Case Histories

- SPE paper 91399 “Microannulus Leaks Repaired with Pressure-Activated Sealant”
- Research Project
  - 650 md before
  - 1.6 md after
- W & T casing leak
  - Over 1000 psi build up in 3 hours
  - Several treatments
  - 75 psi after 43 days

Gel Systems

- Mixed as low viscosity fluid
- Crosslinks at downhole conditions
  - Controllable set time
- Robust ringing gel
- High viscosity but no drillout



Gel Systems' Uses:

- Leaking Liner Sleeves
- Failure or Poor cmt bonds
- Perforation or Fracture of water zones
- Tubing and Casing Leaks
- Channels behind pipe
- Perforation abandonment

Case History

- Casing leaking gas
  - Cement job unsuccessful
- 10 bbls of Gel with fibers
  - Work string used for placement
  - Hesitation squeeze 200 psi
  - 8 bbls of fluid out
  - Shut in for 8 hours
  - Washed out casing

Resin System

- Special Properties (Ultraseal R Patent Pending)
  - High compressive strengths/shear bonds/tensile strengths
  - Non Shrinking/Water Tolerant
  - Cures at 40 F to 350 F
  - Total Liquid System
    - Penetrates small channels/micro-annulus
  - Controlled Pump Times and Set Time
  - Density from 7 ppg to 16.5 ppg
  - Drills out easily

Applications for Resin

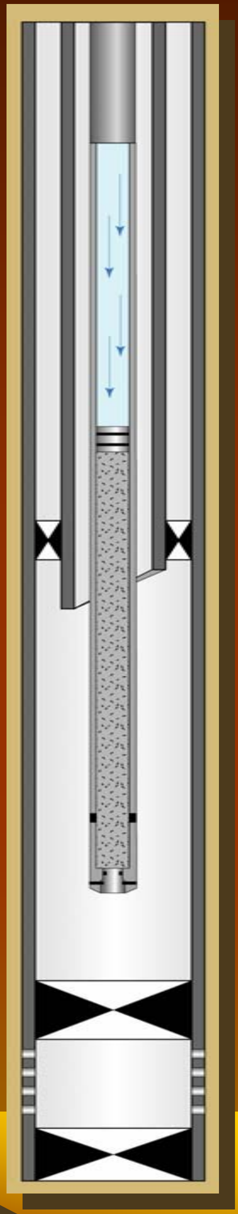
- Shut off of gas for abandonment or SCP
- Seal leaking packers
- Shut off gravel pack
- Pressure seal for Annulus or pipe
- Casing leaks

Case History

- Gas leaking from two annuli
  - Make several cuts in both pipes
  - Run acid wash
- Pump 5 bbls of Resin in at surface
  - Allow to fall to top of bridge plug
  - Put 200 psi above gas pressure build up for 24 hours
- No gas pressure or bubbles at surface

Special Control Volume Displacement System

The TTS Series 5200 Controlled Volume Displacement System (CVDS) is designed to remedy this problem. The CVDS utilizes a series of polished ID tubulars to hold fluid volume. The system's design allows for spotting of a specific fluid volume at a specific location in the well.



Conclusions

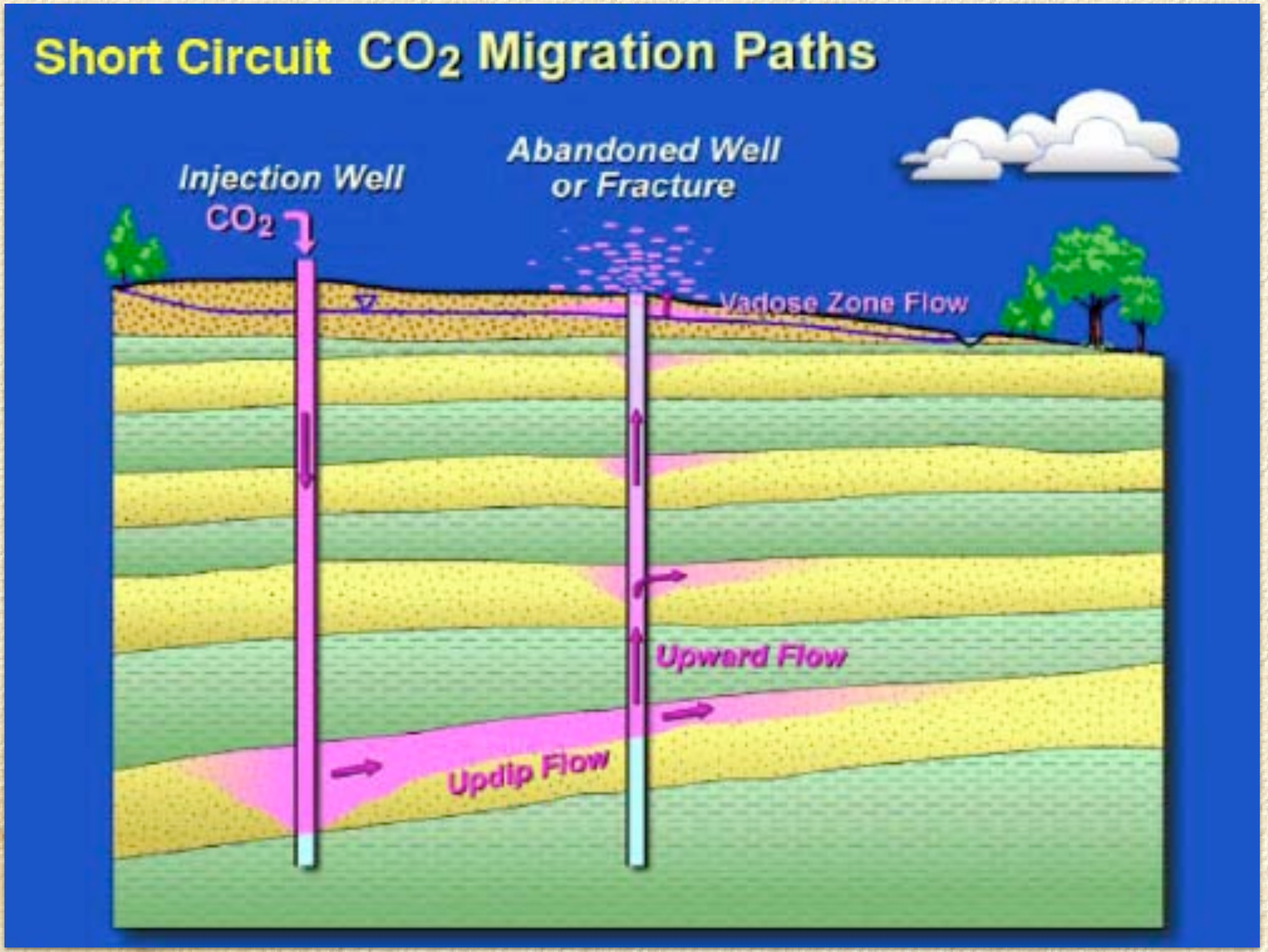
- Many products/methods are used for SCP
- Most products can work depending on situation
- Key – finding source and applying right product
- Problems:
  - Accessing gas in many annuli
  - Placing product – rigless, coil, etc
  - Putting holes/cuts in pipe
  - Placement and drillout
  - Expense

Geological Storage of CO_2

Evaluating the Risk of Leakage

Injection & Leakage

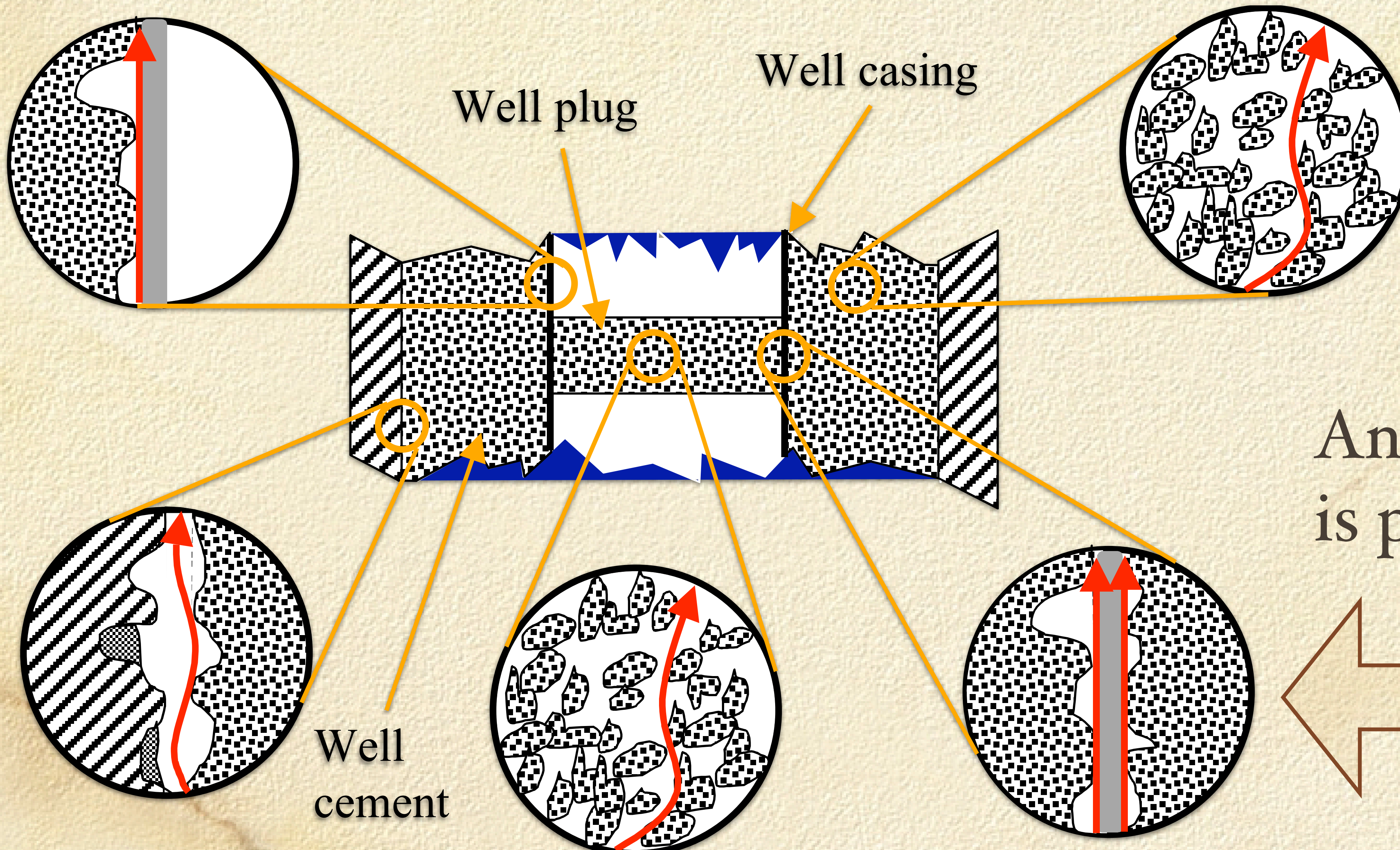
- Reservoir model must predict composition of brine that comes into contact with cement



From *Canadian CO_2 Capture and Storage Roadmap Strawdog*, Bill Gunter, Alberta Research Council

Potential Leakage Routes

- Greatest risk is from acid flow through annulus



Annular gap is primary focus

Injection, Transport & Leakage

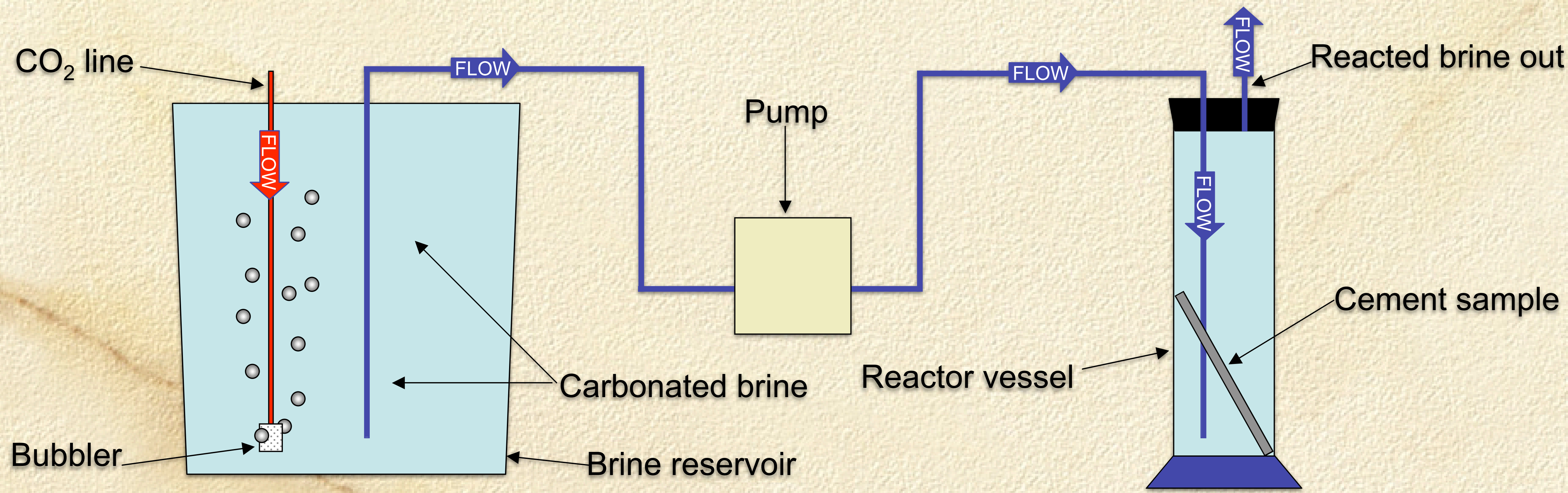
- Model of injection & transport
  - *What is the fluid that reaches the cement?*
- Experimental study of cement corrosion
  - *How does cement respond to acidic brine?*
- Model of acidic brine in annulus
  - *How quickly does a leak increase?*

Corrosion of Cement
(*Andrew Duguid, Mileva Radonjic, GWS*)

- Cement paste with 0, 6, or 12 % bentonite
  - Flow-through experiments to find maximum reaction rate
  - Batch reactions to study transport control
- Field samples from Teapot Dome
- High *P* & *T* studies with NETL
  - Simulate Teapot Dome cement recipe

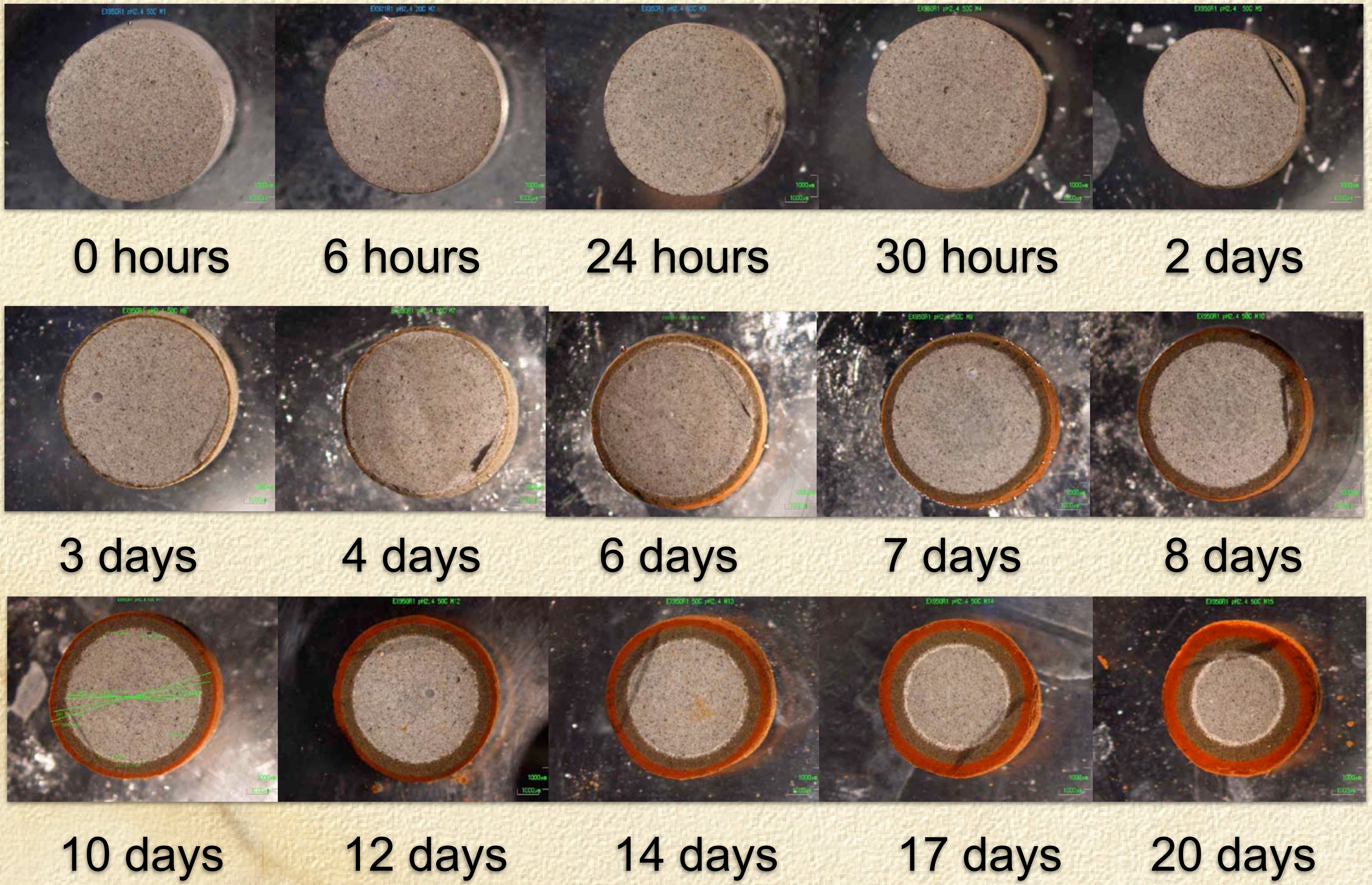
Flow-Through Experiment
(Continuous fresh acid)

- Acidified brine passes over rod of cement
- Provides maximum rate of reaction (*i.e.*, no limitation from saturation of solution or diffusion of reaction products)



Flow-Through Experiment
(Continuous fresh acid)

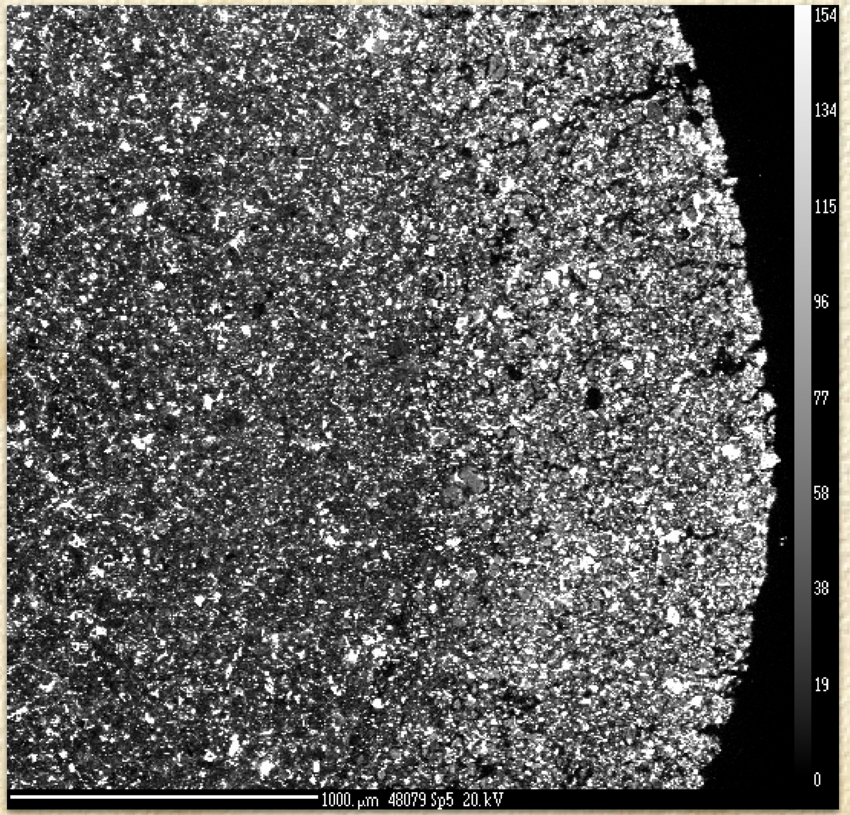
- Sandstone formation: pH 3 , 50°C



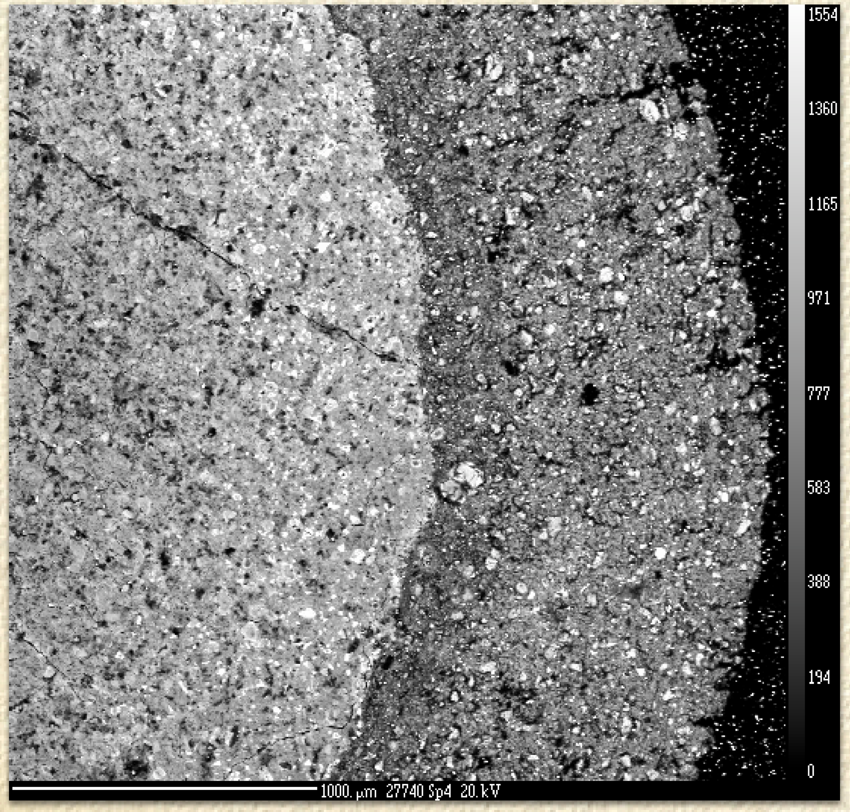
Composition Maps

- Calcium removed from outer layer
- Silicon slightly depleted
- Iron unchanged

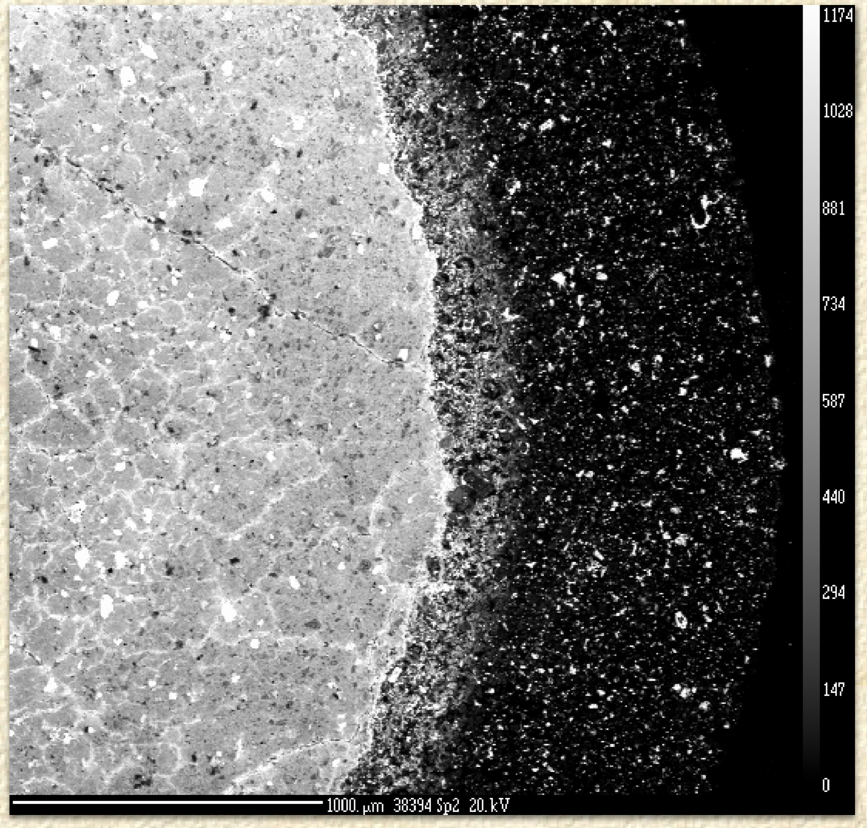
Iron



Silicon

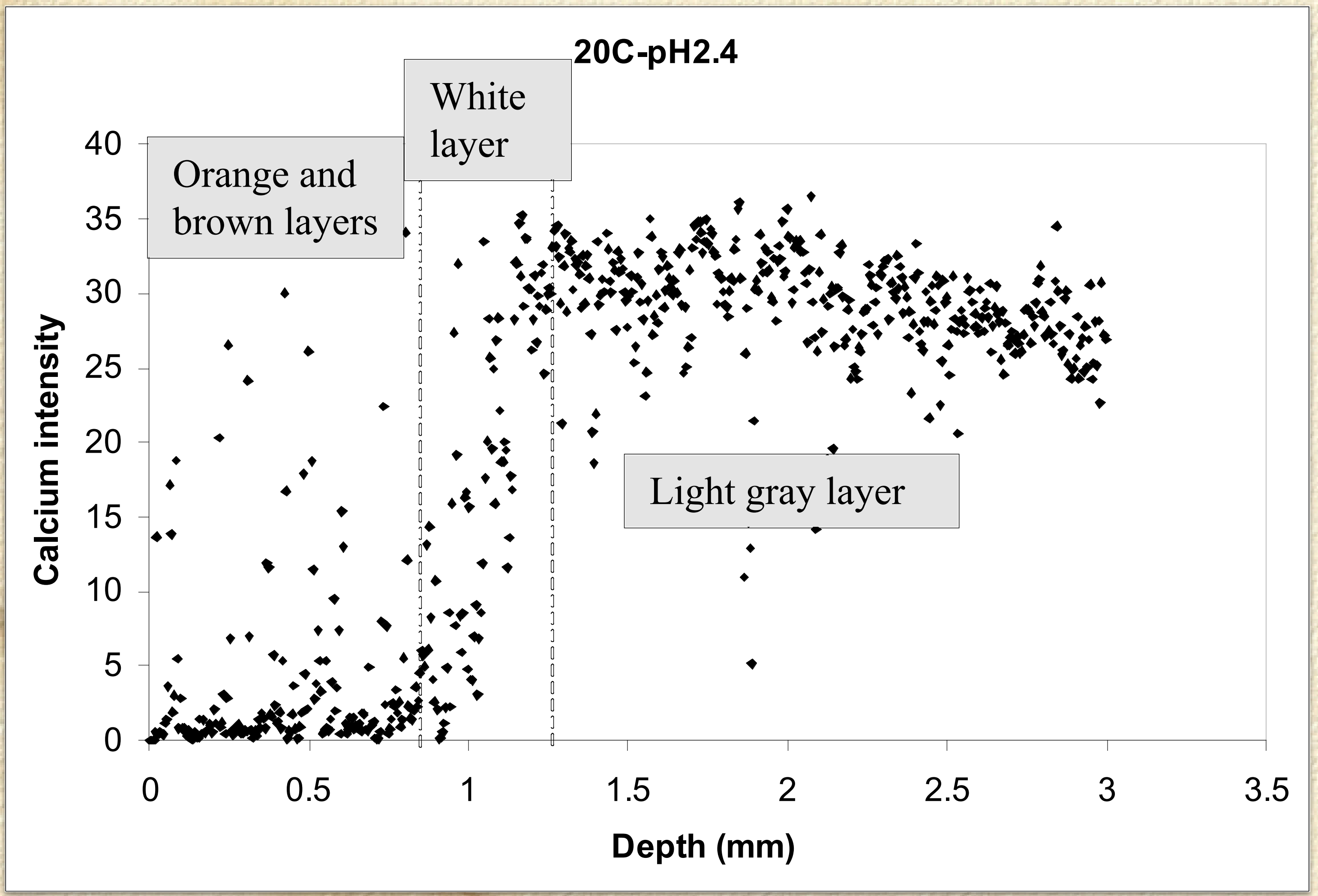


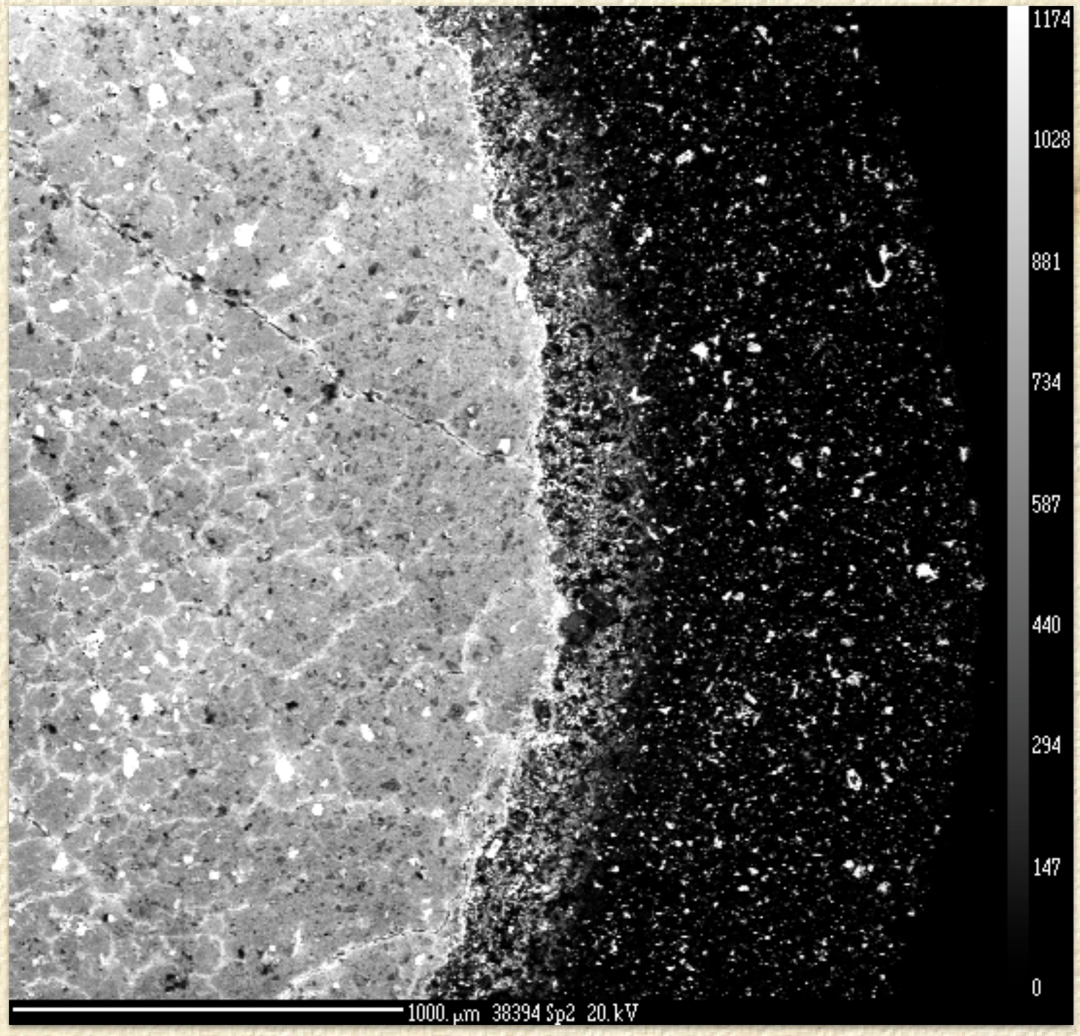
Calcium



X-ray Maps

- Provide data for detailed testing of models

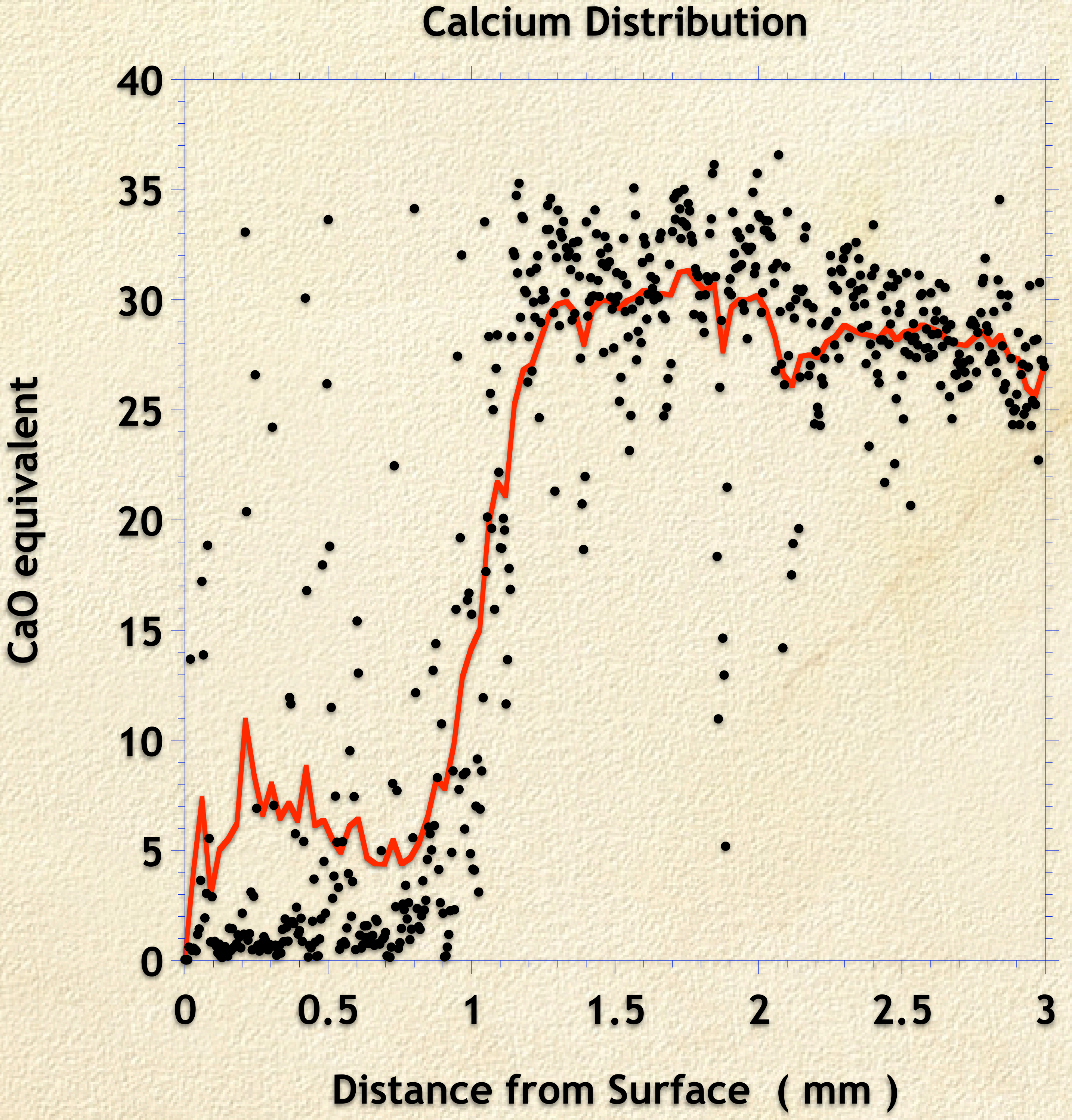




X-ray map for calcium in a sample reacted at 20C-pH2.4

Quantitative Profiles

- Calcium is gone from outer layer
- This layer is so soft that it washes off

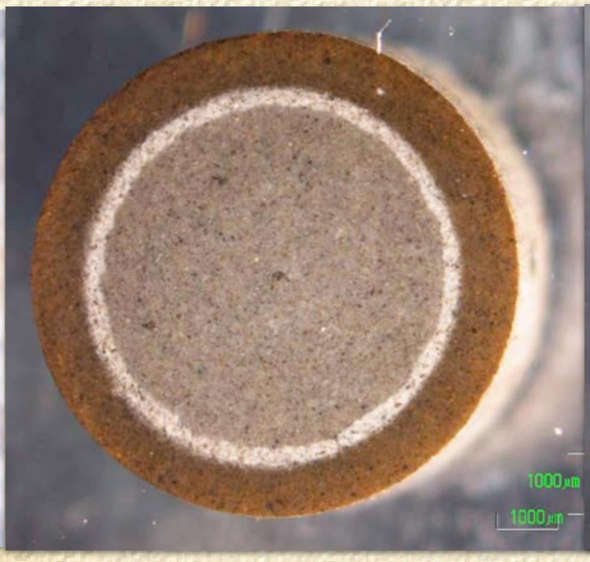


Flow-Through Experiment
(Continuous fresh acid)

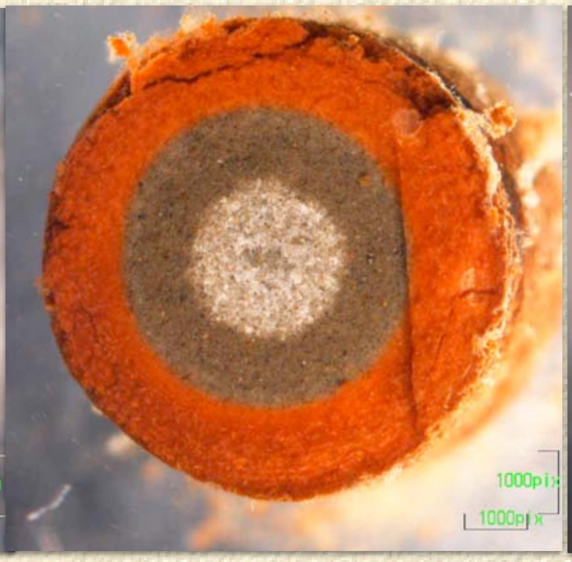
- Corrosion is strongly accelerated by
  - lower pH
  - higher temperature

23°C pH 2.4

23°C pH 3.7



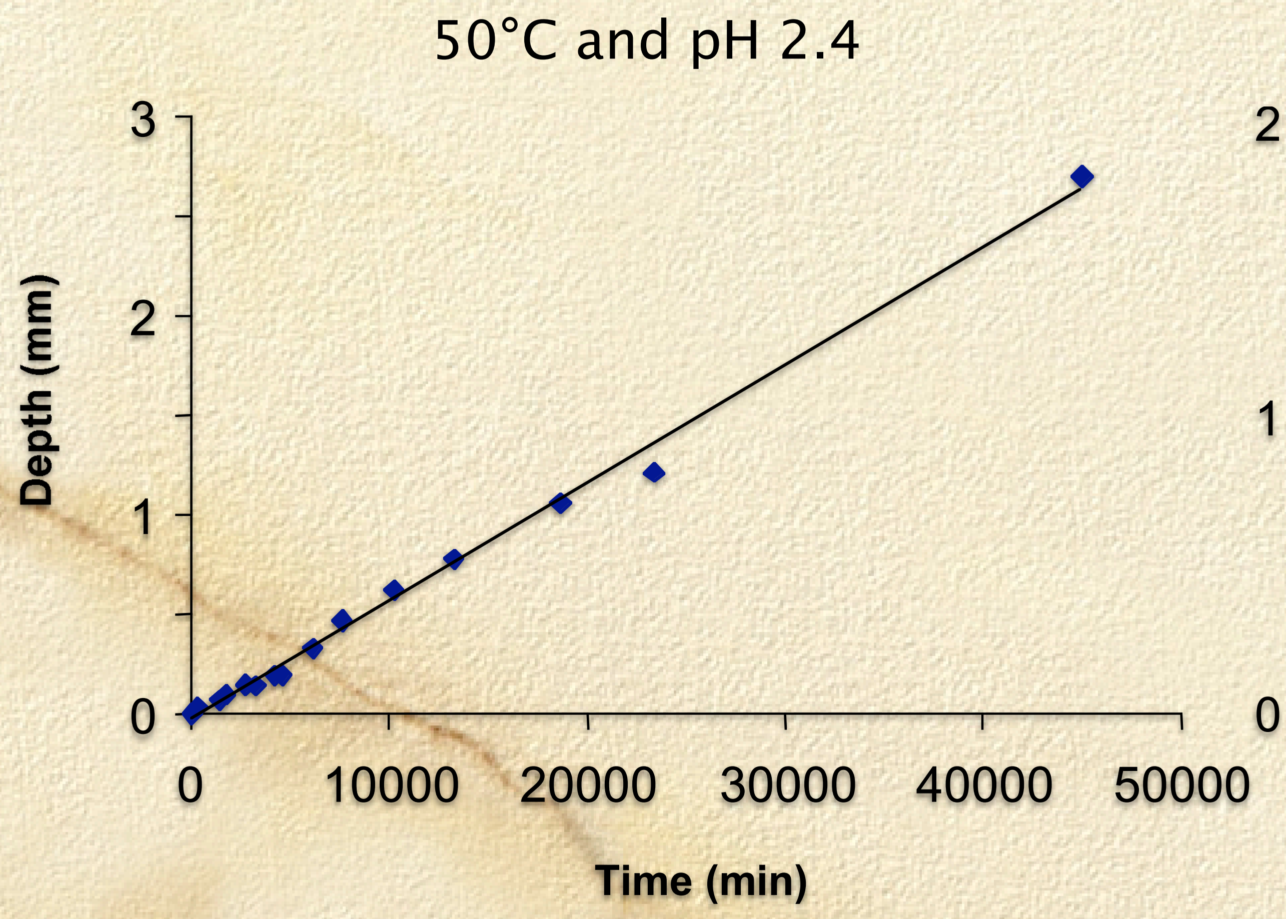
50°C pH 2.4

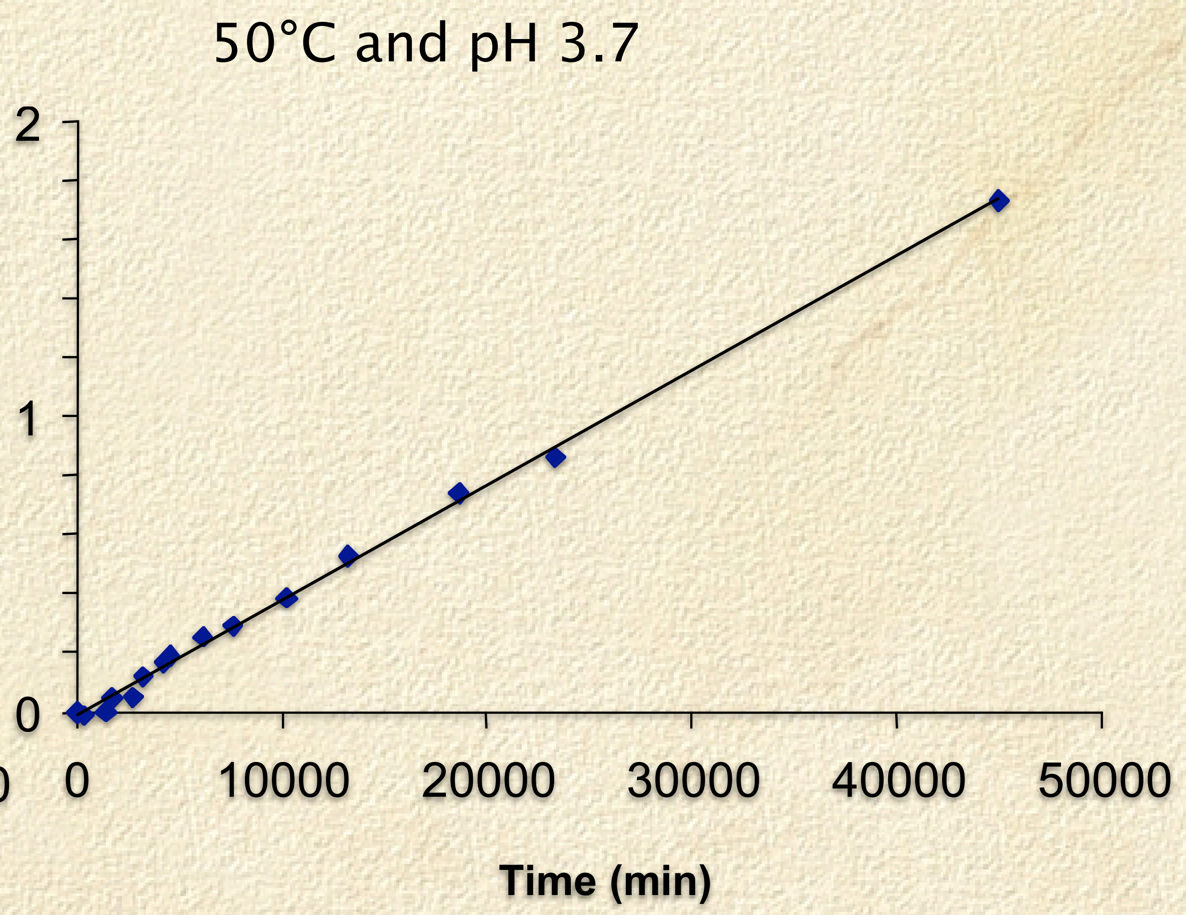


50°C pH 3.7

Flow-Through Experiment
(Continuous fresh acid)

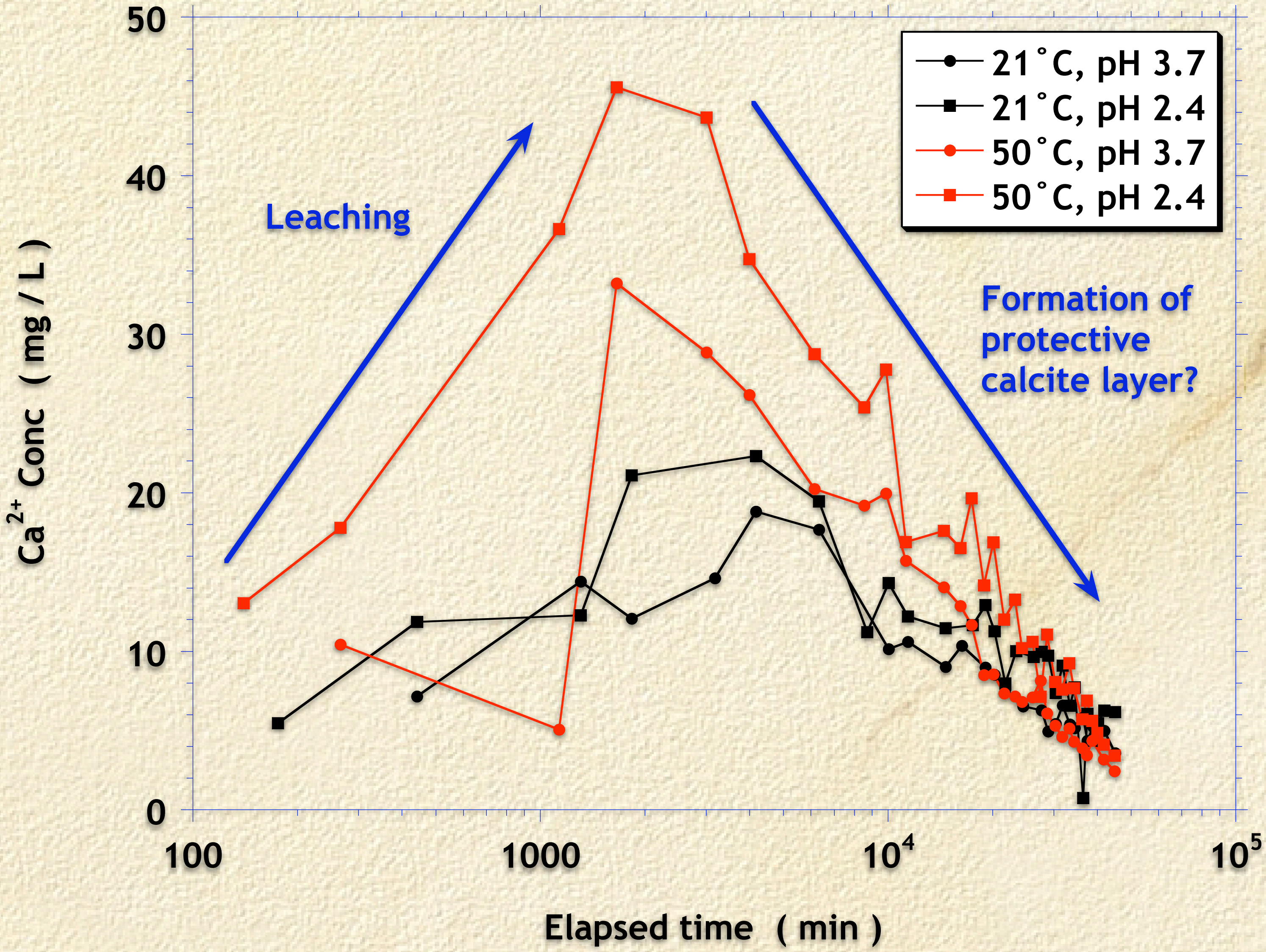
- Under typical conditions of a sandstone formation at ~1 km depth, the rate of attack would be roughly 2 - 3 mm per month *if fresh acid flowed over the cement*





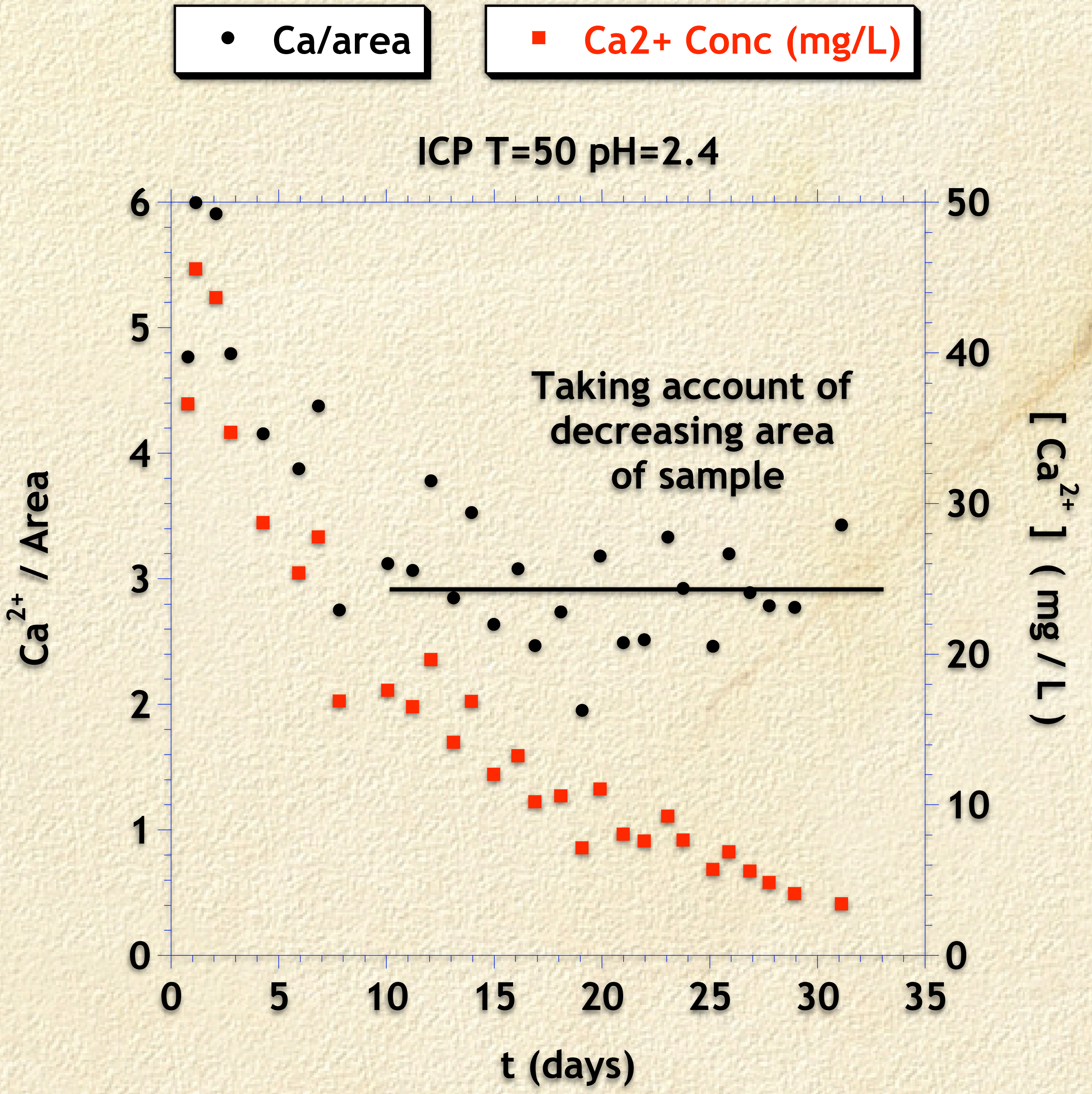
Composition of Effluent

- Water exiting reactor shows initial rise in calcium as acid attacks cement
- Subsequent exponential drop may reflect protective effect of white calcite layer
  - Consistent with plateau in permeability



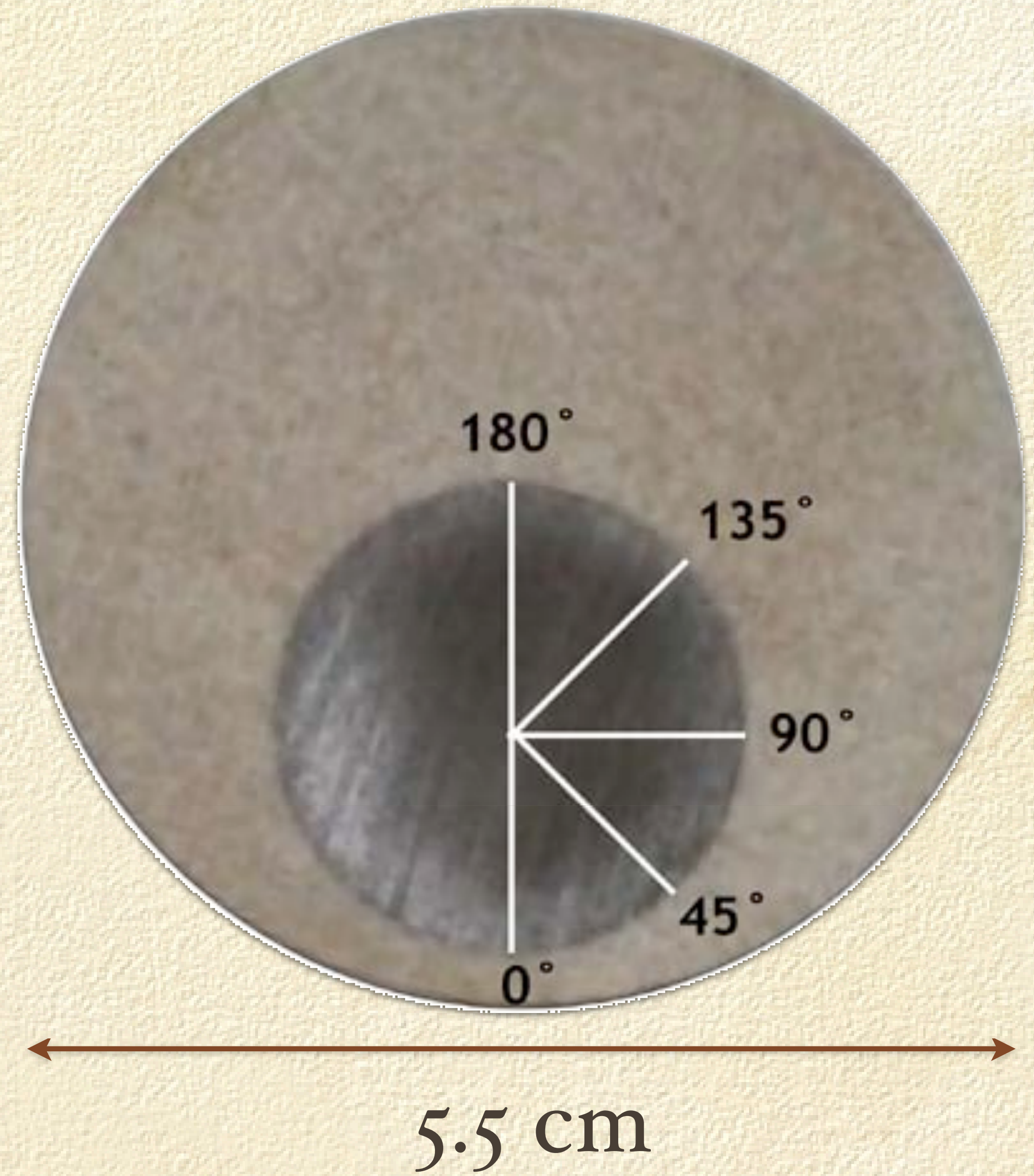
Analyzing Effluent

- Most of drop in Ca^{2+} results from decreasing area of unreacted core (see black dots)
- Probable increase in solute content at interface (but not diffusion control)



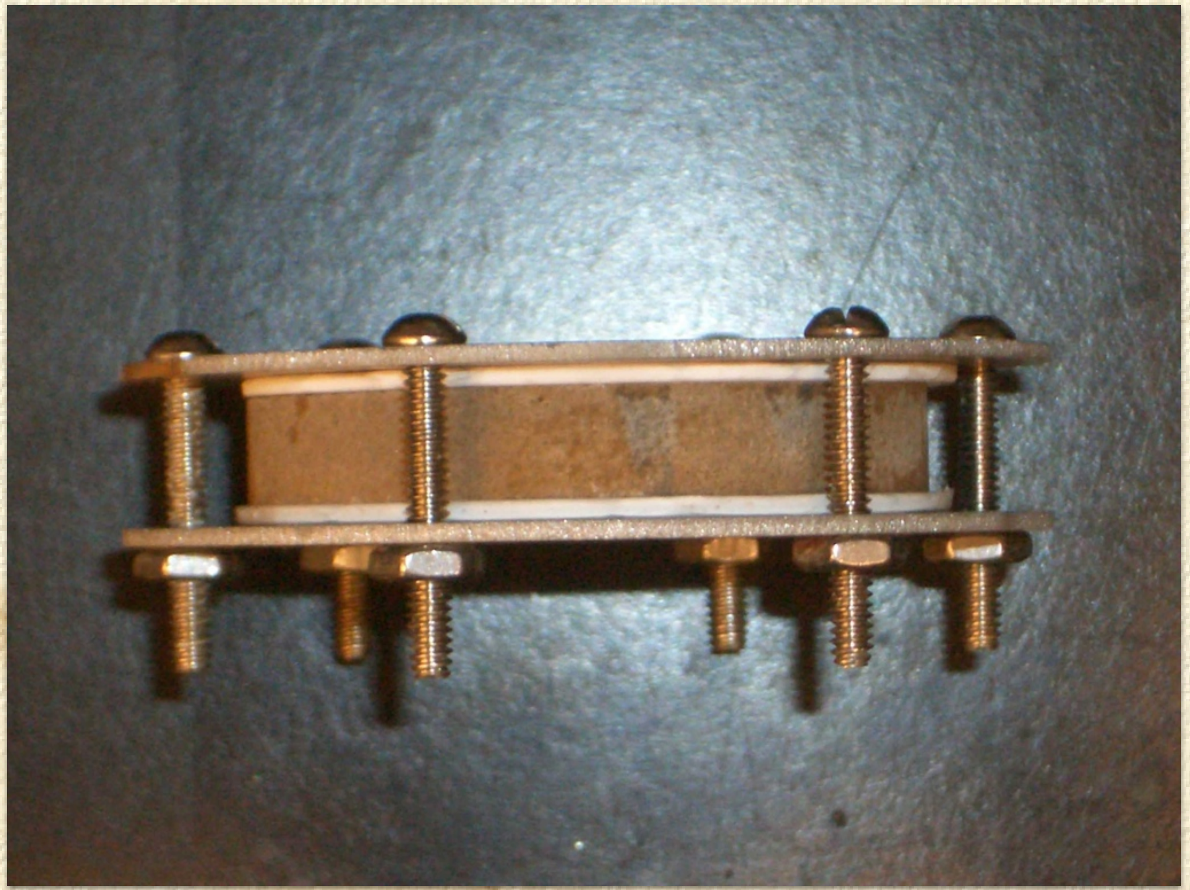
Batch Samples: Cement in Stone

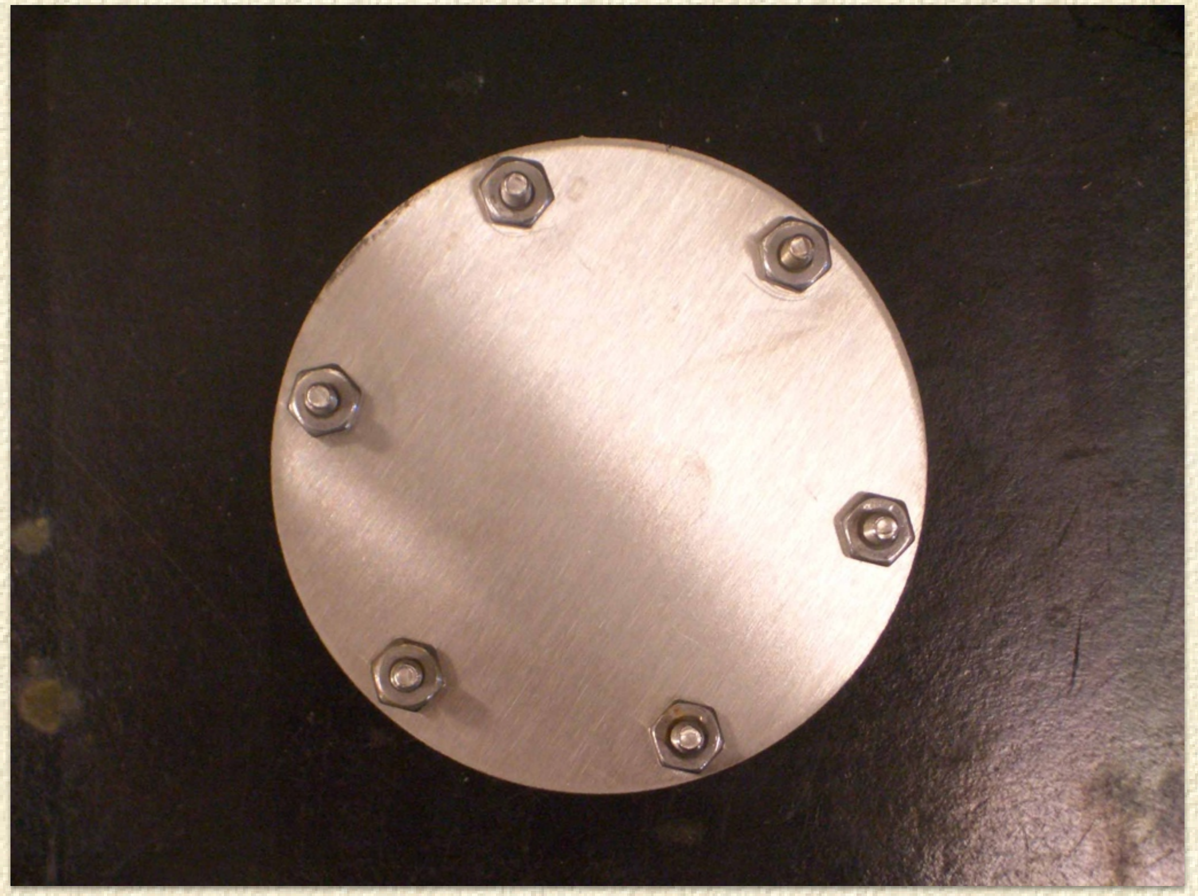
- Cement (25 mm) in 55 mm disk of stone (Berea sandstone or Salem Limestone
- Acidified brine penetrates radially (faces sealed)
- Rate of attack varies with distance from surface



Batch Experiments

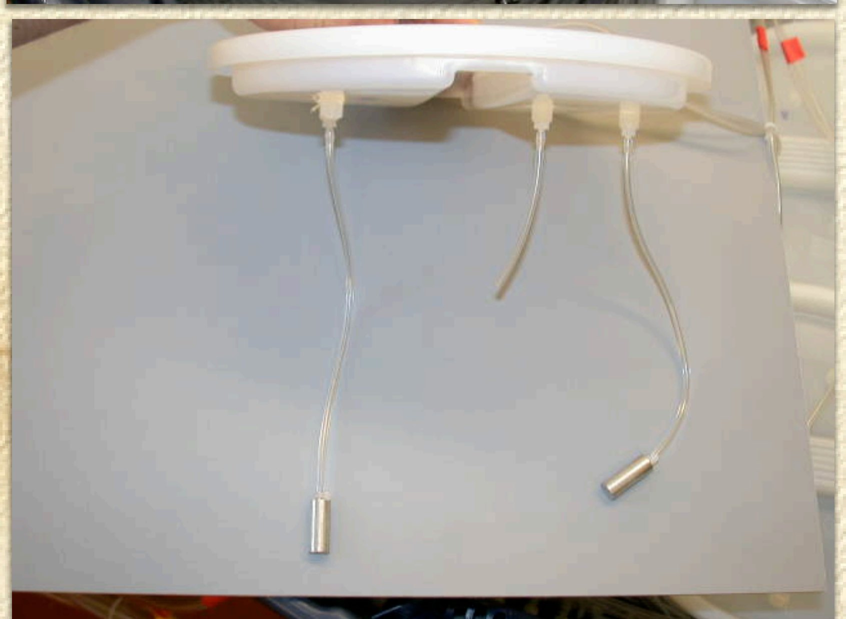
- Cement-in-Stone samples sealed between sheets of teflon and plates of stainless steel





Batch Experiments

- Samples immersed in jugs with CO_2 bubbling and brine with controlled pH



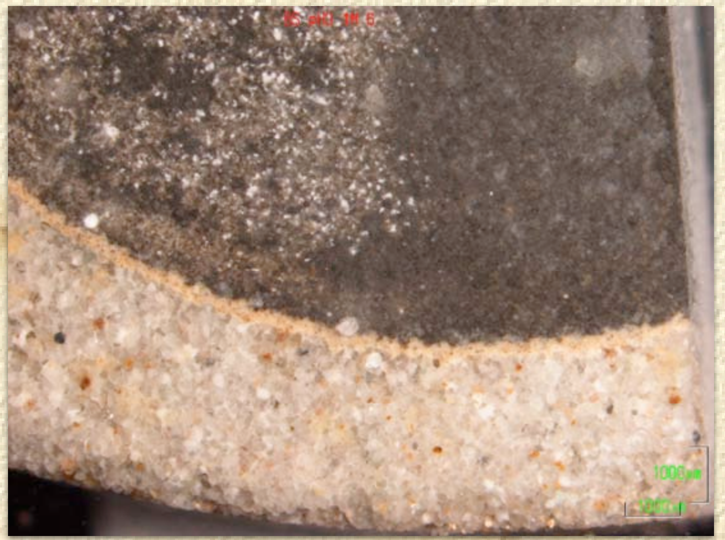
Batch Experiments

- Plastic jugs containing samples are stored in large vats at controlled temperature (23 & 50°C)
- Tanks of brine maintain pH and CO_2 content
- Composition and pH of outflow monitored

Batch Experiments
(Static acidic brine)

- Sandstone + Cement
  - 23 & 50°C
  - pH 3, 4, 5

- Distinct reaction rim after exposure (pH 3, 23°C)



One Month

Two Months

Three Months

Batch Experiments
(Static acidic brine)

- Limestone + Cement
  - 23 & 50°C
  - pH 5, 6, 7

- Higher pH and dissolved calcium content reduces rate of attack (no reaction rim yet)

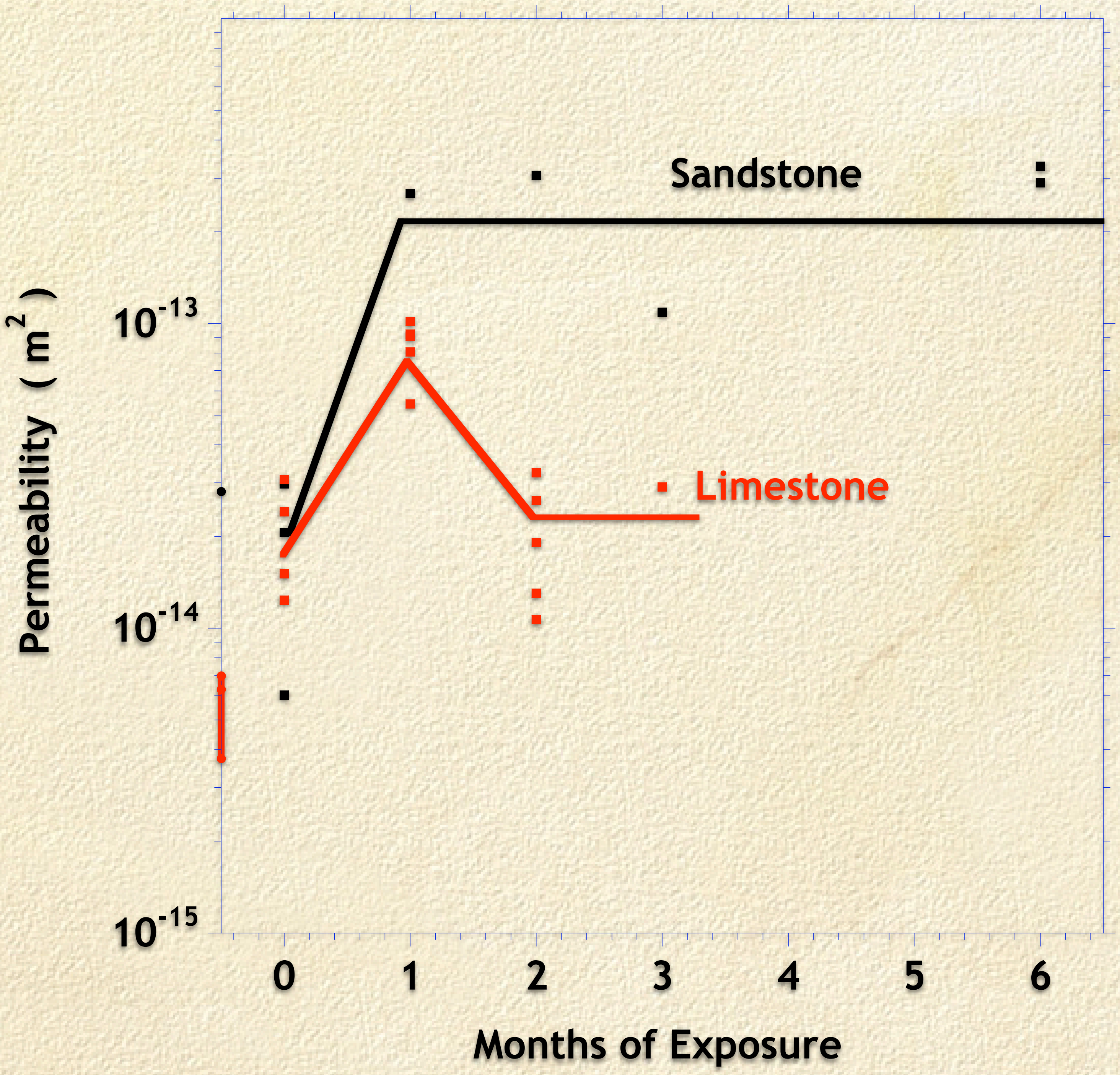
One Month

Three Months

Six Months

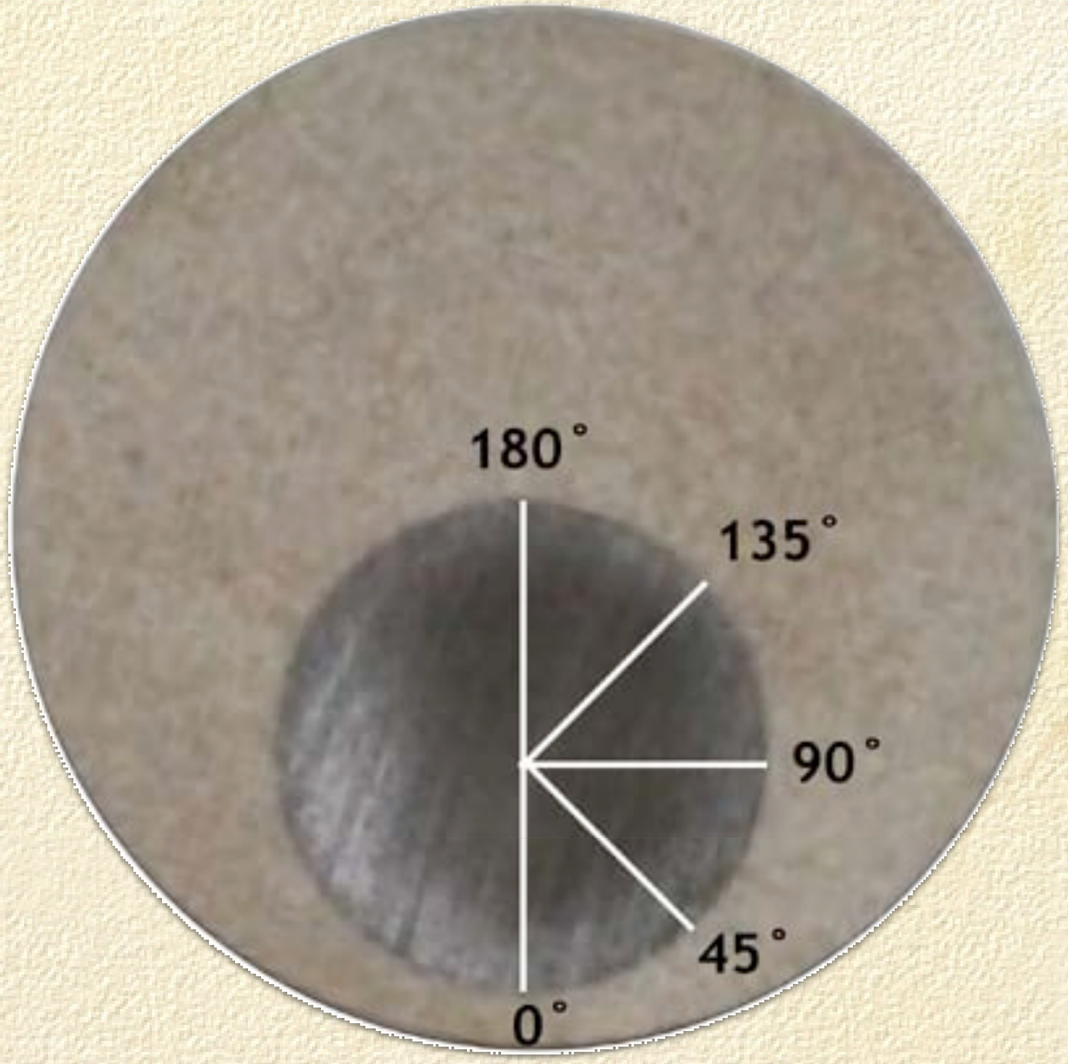
Permeability of Batch Samples

- Sandstone samples show 10-fold increase in 1 month
  - Equivalent to hole 0.4 mm in diameter
- Limestone shows little change



Batch Samples: Cement in Stone

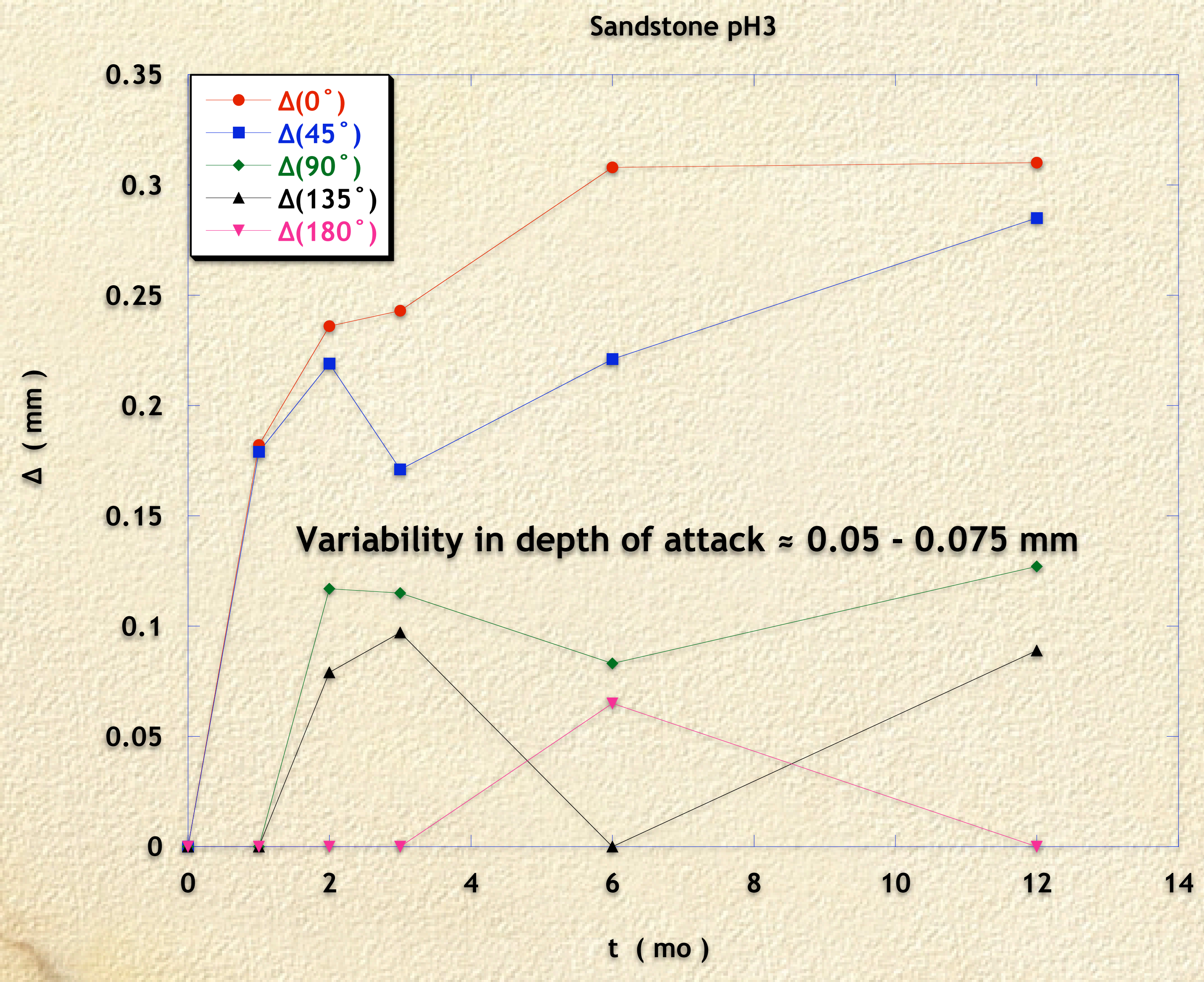
- Acidified brine penetrates radially (faces sealed)
- Rate of attack varies with distance from surface
- Expect diffusion control, corrosion depth $\propto$ $t^{1/2} / r$



5.5 cm

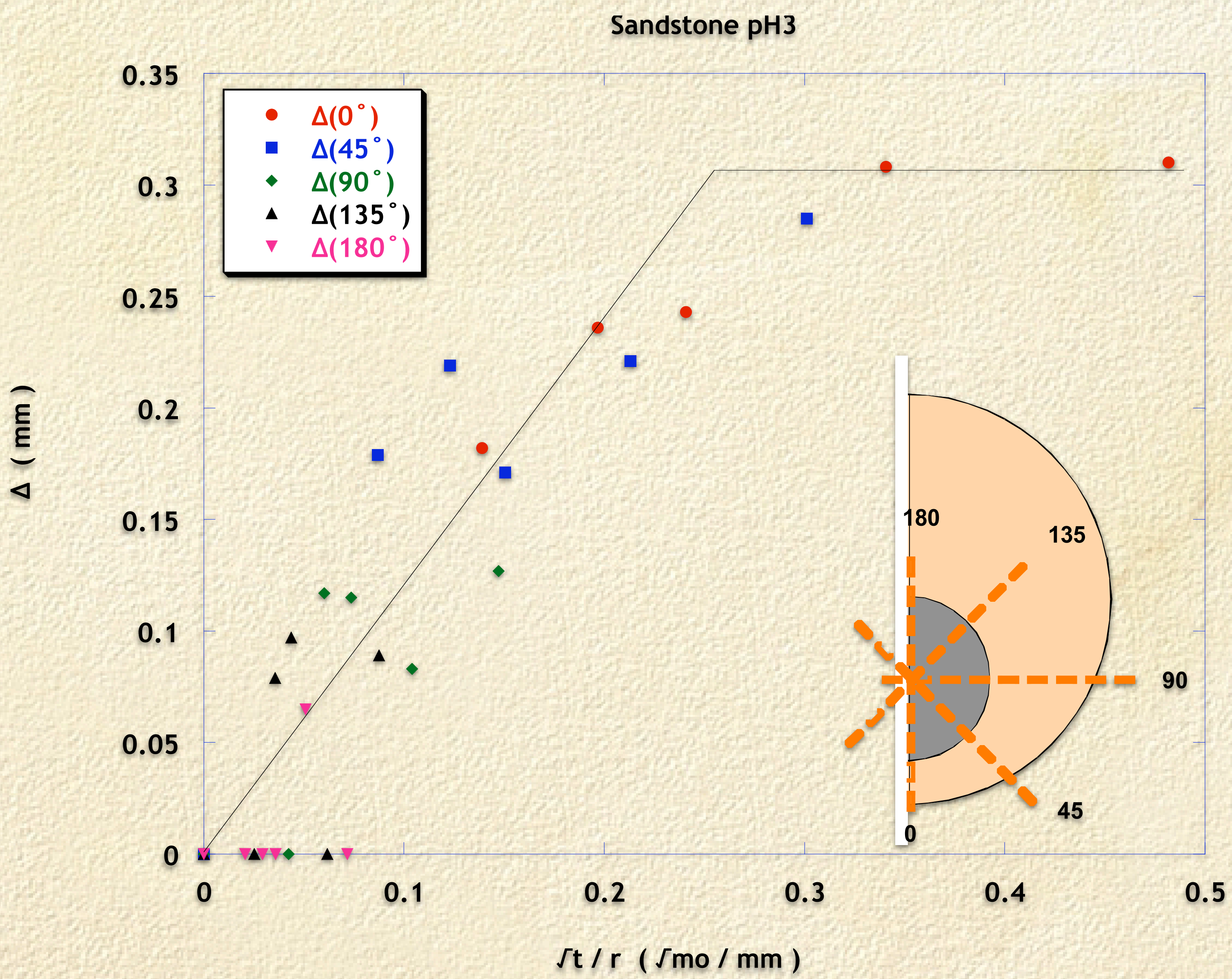
Non-linear Corrosion Rate

- Shape of curves suggests diffusion control (23°C)



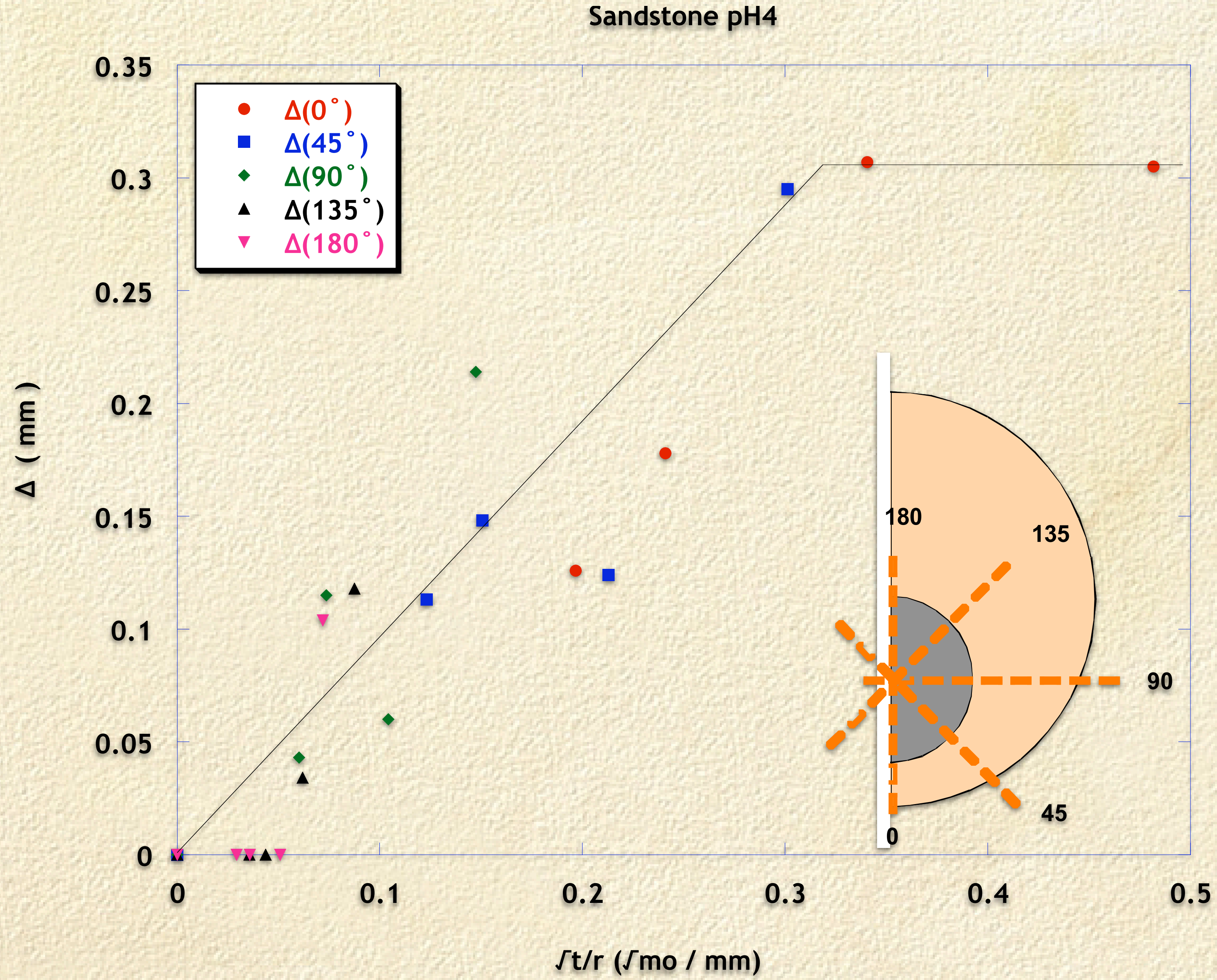
Diffusion-Controlled Corrosion (pH 3, 23˚C)

- Depth of attack initially diffusion controlled
  - Collapses against Boltzmann variable, $t^{1/2} / r$
- Depth seems to plateau after ~300 µm penetration



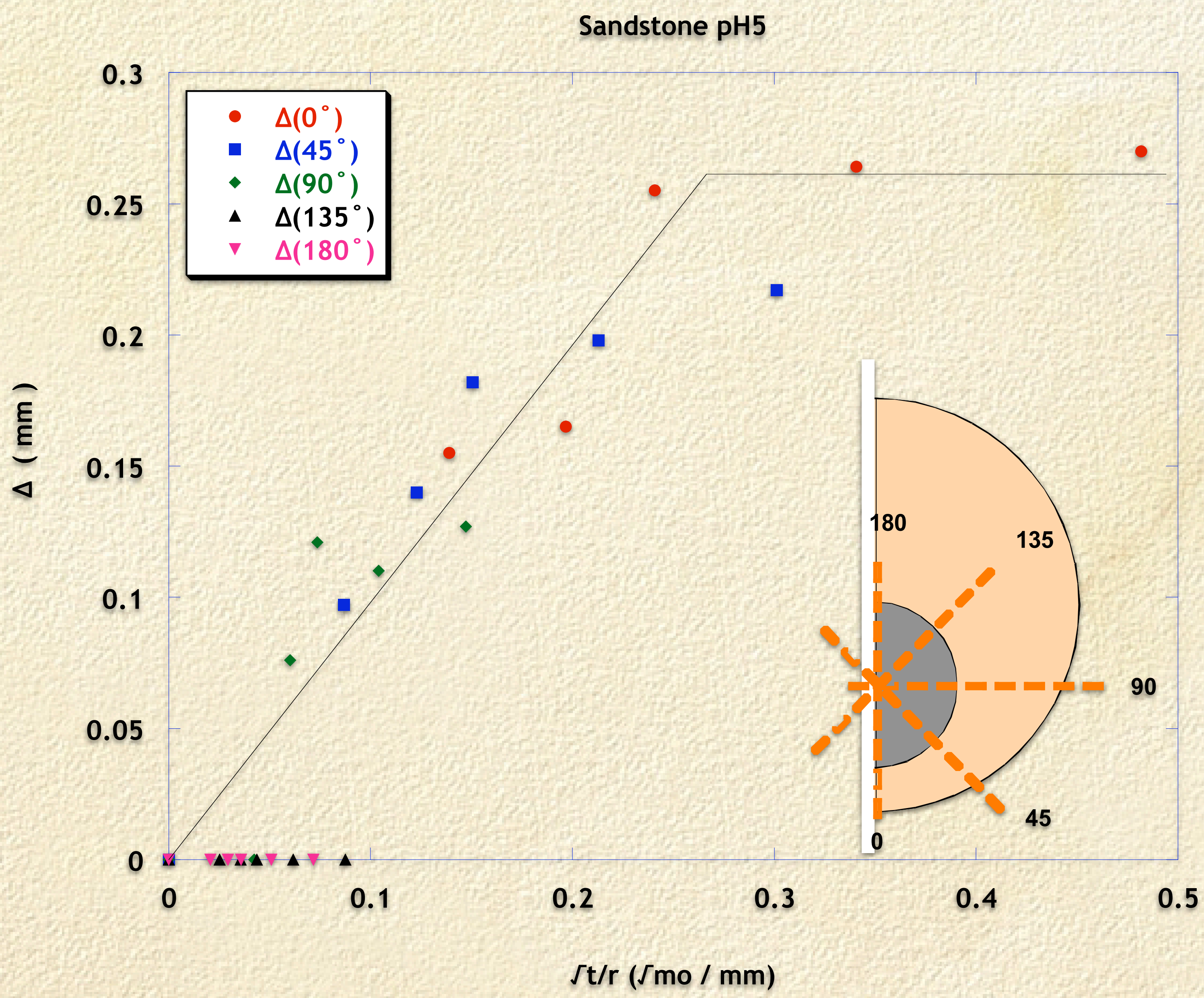
Diffusion-Controlled Corrosion (pH 4, 23°C)

- Depth of attack initially diffusion controlled
  - Collapses against Boltzmann variable, $t^{1/2}\,/\,r$
- Depth seems to plateau after ~300 µm penetration



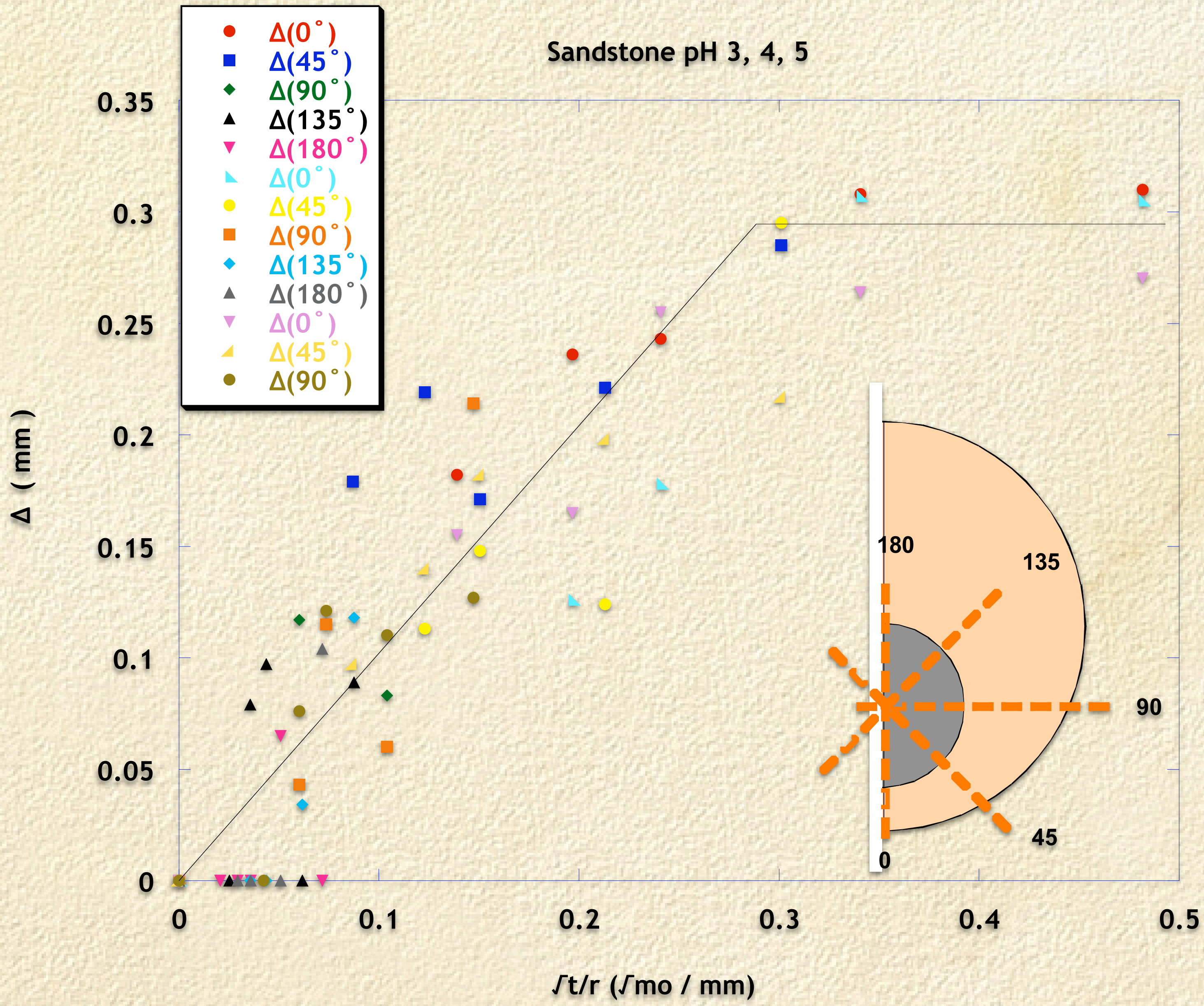
Diffusion-Controlled Corrosion (pH 5, 23°C)

- Depth of attack initially diffusion controlled
  - Collapses against Boltzmann variable, $t^{1/2} / r$
- Depth seems to plateau after ~300 µm penetration



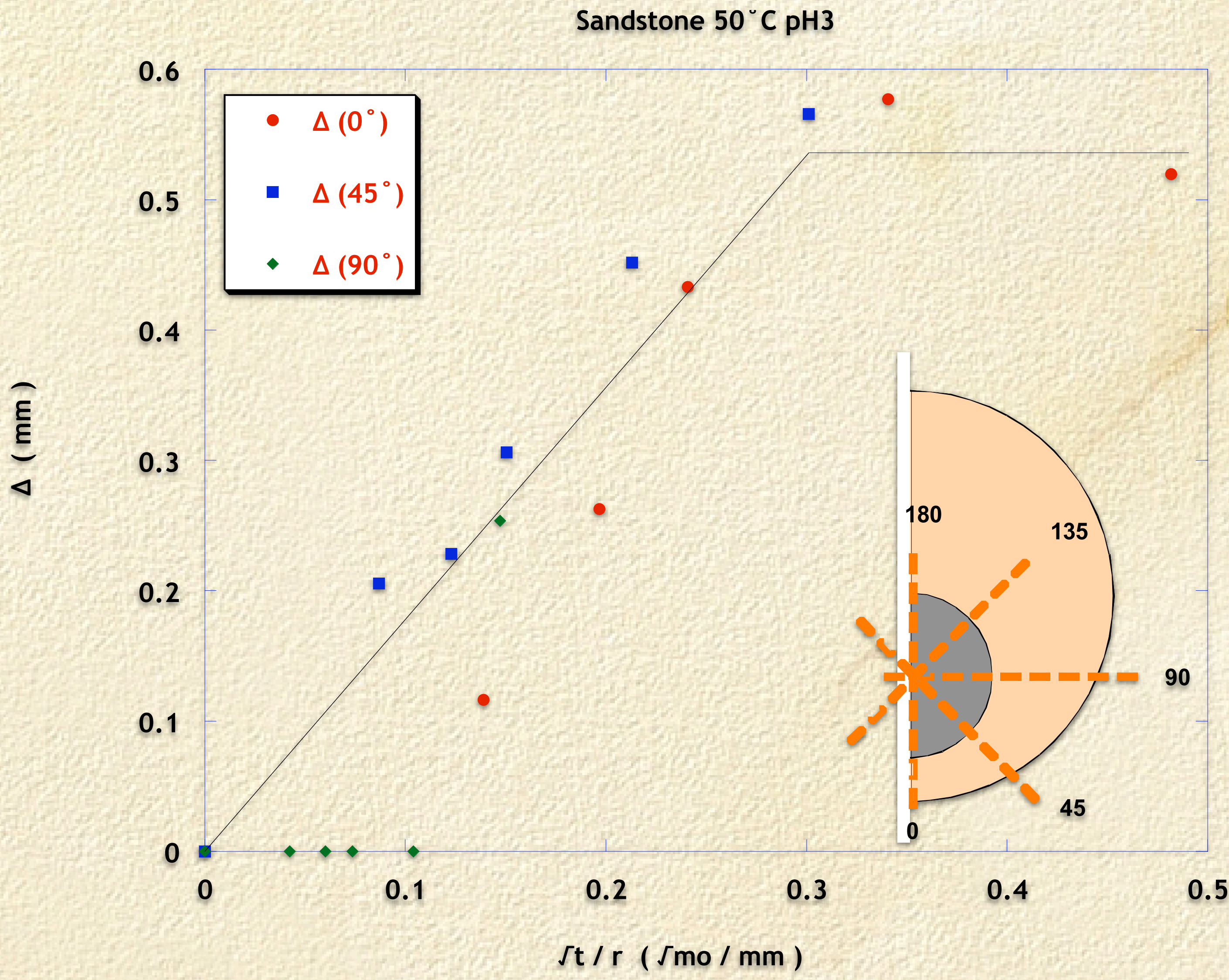
Diffusion-Controlled Corrosion (23°C)

- Data for all pH's show common trend
  - Collapse against Boltzmann variable, $t^{1/2} / r$
- Depth seems to plateau after ~300 μm penetration



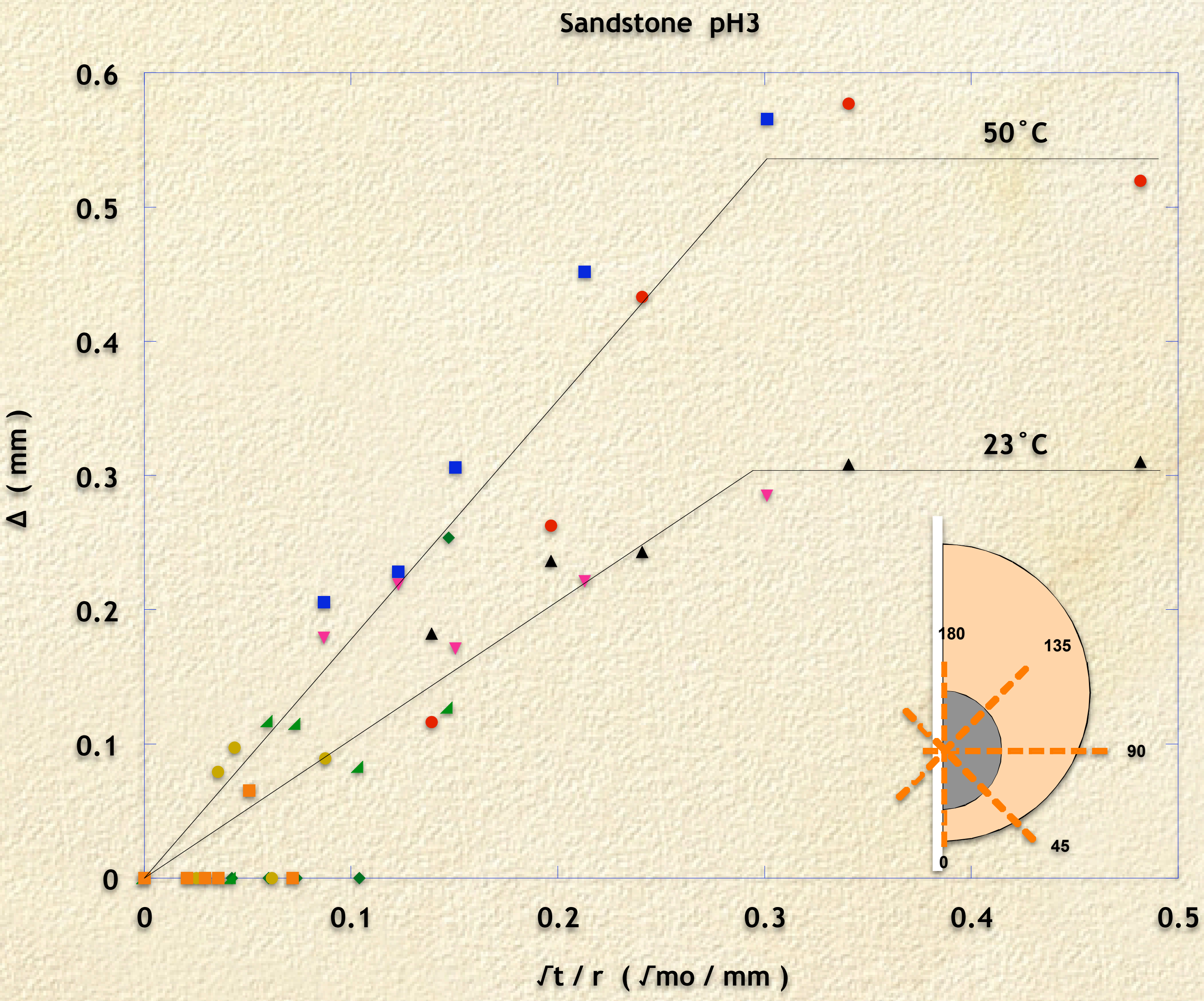
Diffusion-Controlled Corrosion (50°C)

- Depth of attack initially diffusion controlled
  - Collapses against Boltzmann variable, $t^{1/2} / r$
- Depth seems to plateau after ~550 µm penetration



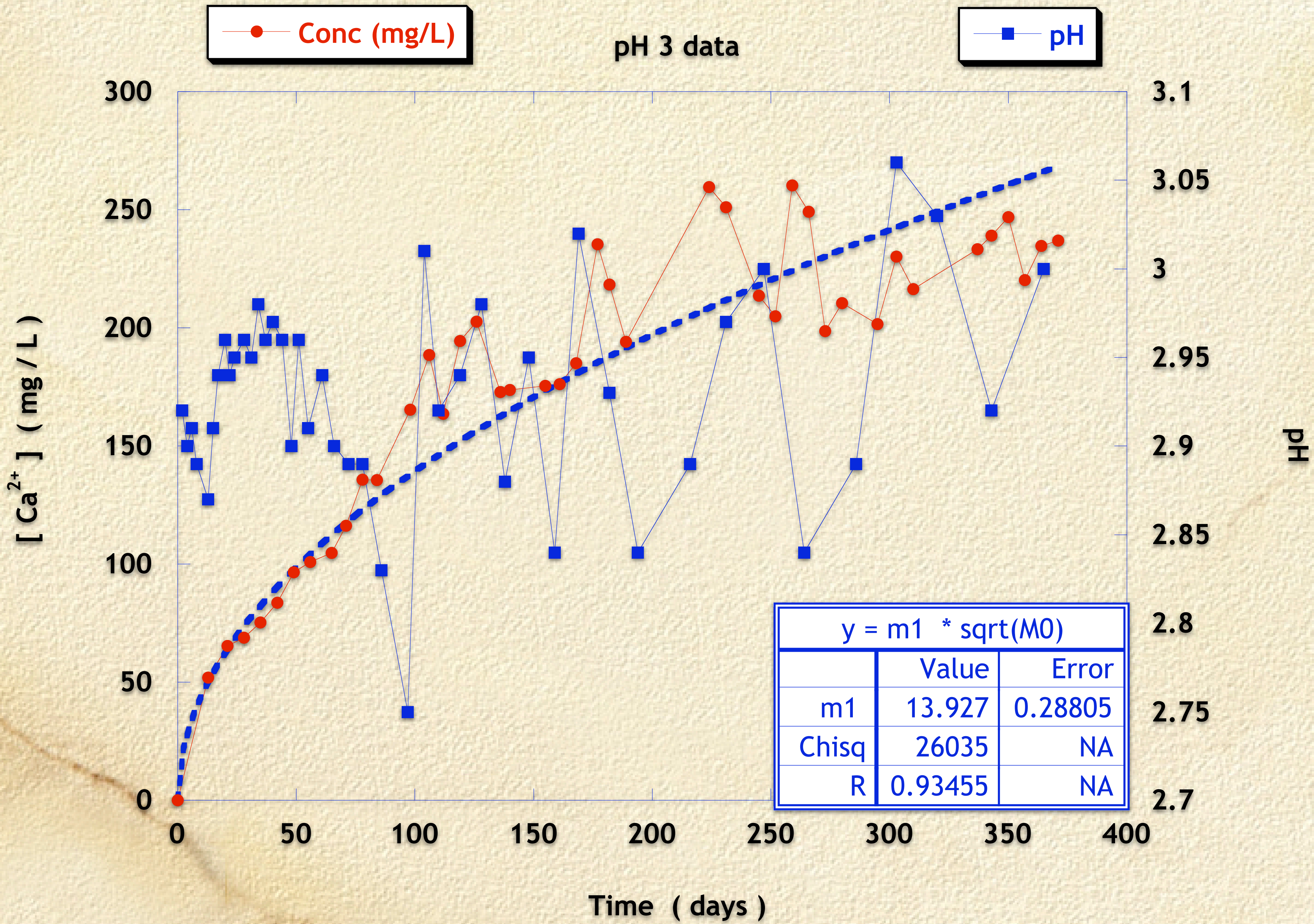
Diffusion-Controlled Corrosion

- Depth of attack initially diffusion controlled
  - Collapses against Boltzmann variable, $t^{1/2} / r$
- Depth seems to plateau after ~3-500 µm penetration at both temperatures



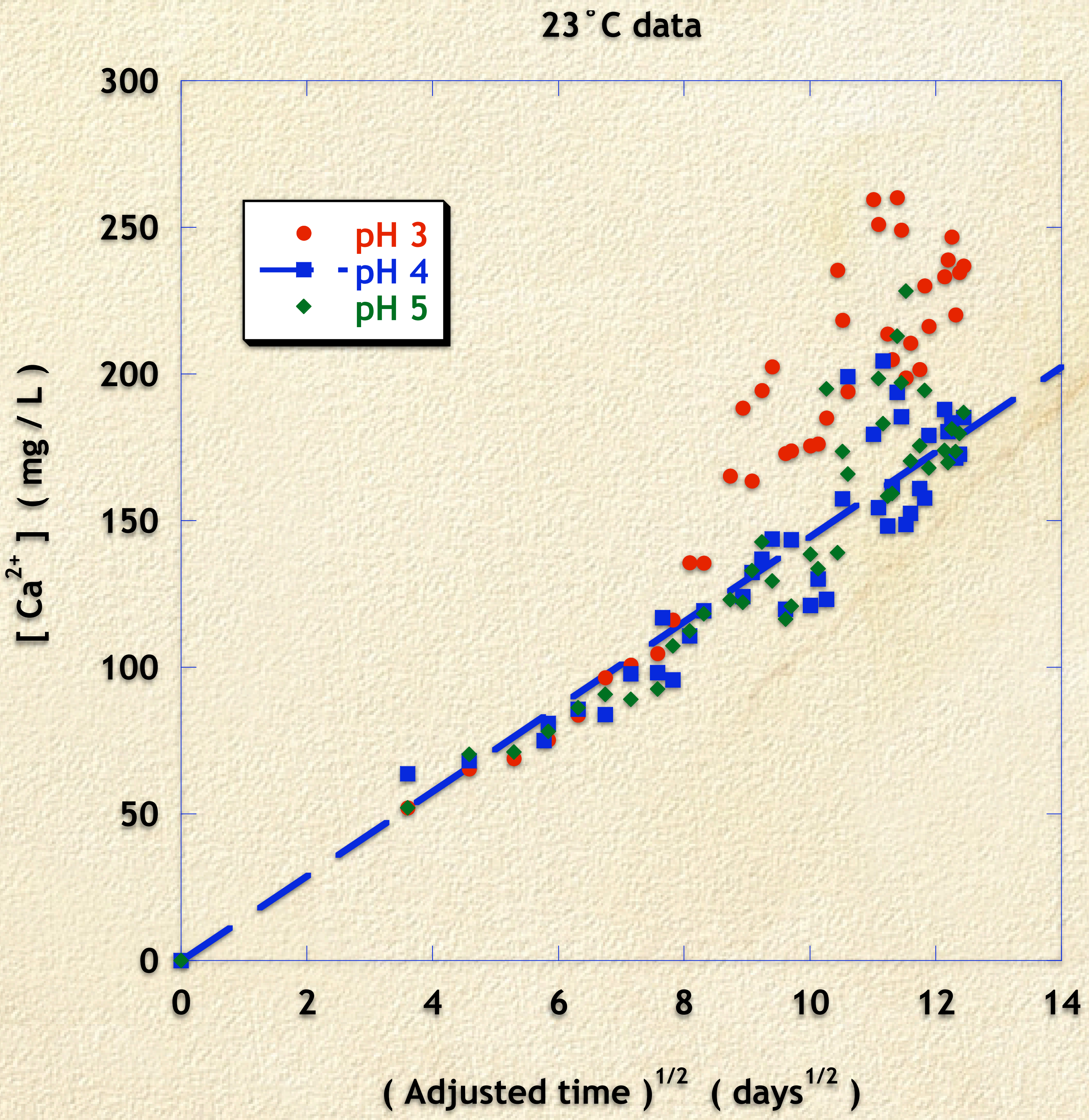
Ca^{2+} Release

- Roughly √t , some spikes when pH adjusted



Kinetics of Release

- Total release must be corrected for removal of samples at intervals (1, 2, 3, 6, 12 months)
- Release rate seems to show increase at long time
- Consistent with transition to linear kinetics



Kinetics of Release

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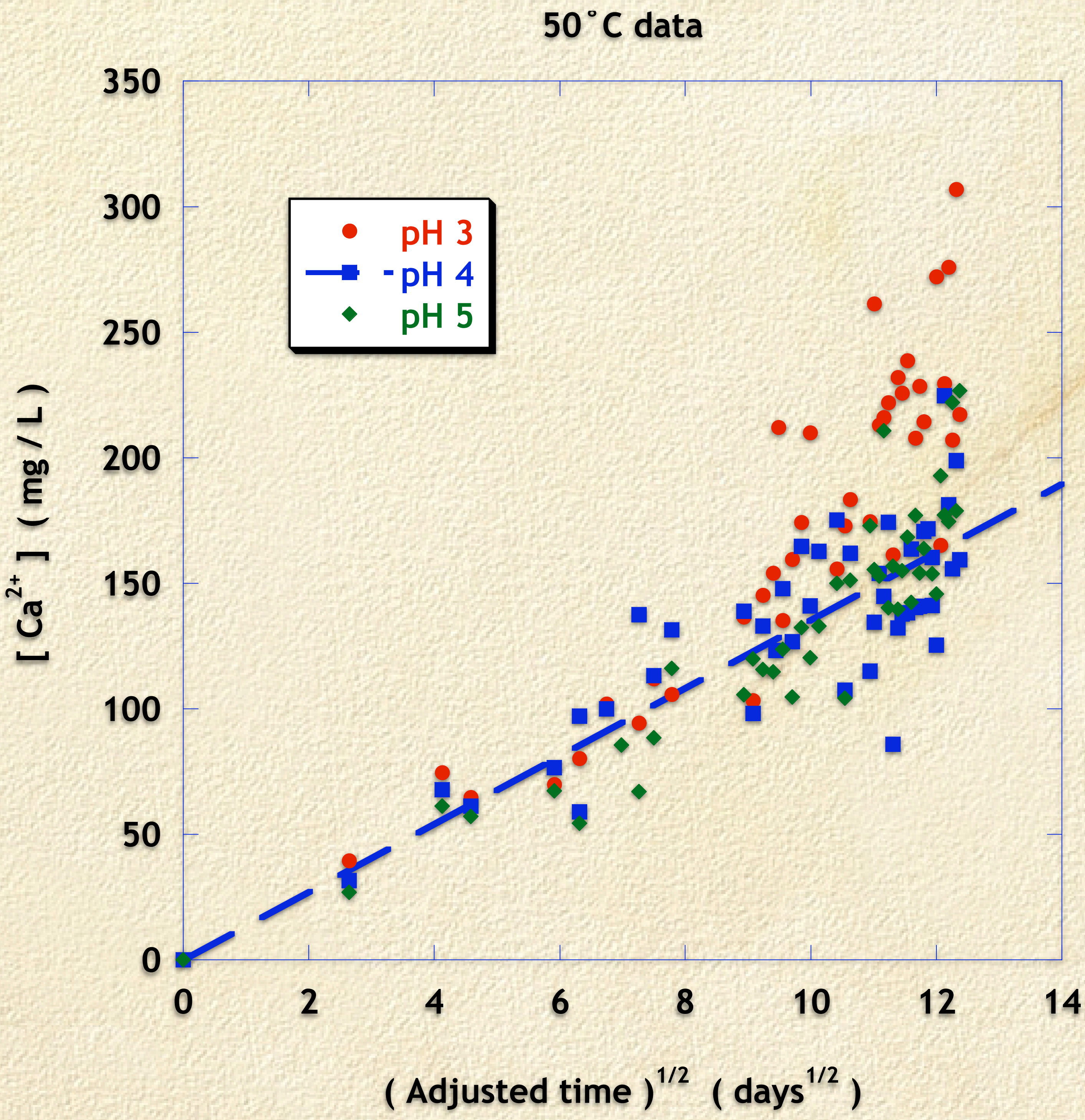


Conclusions

- Reaction rate is fast - several mm per month - under steady flow of acidic brine
- Even under diffusion control, attack is evident within weeks under conditions characteristic of sandstone formation
  - Much less rapid attack in limestone
  - Rate of attack slows as layers develop
    - Protective calcite layer?
- Quantitative data will permit modeling of attack in annulus
  - Begin by modeling batch experiment

Core-flood and Batch Experiments on Carbonation of Casing-Cement-Shale Composites

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

Los Alamos National Lab

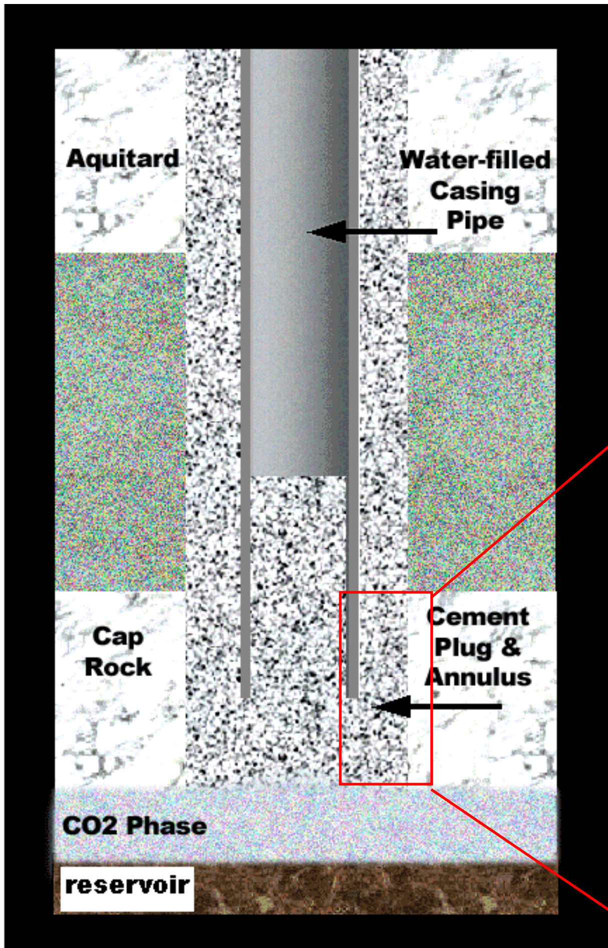
Reid Grigg and Bob Svec

New Mexico Tech

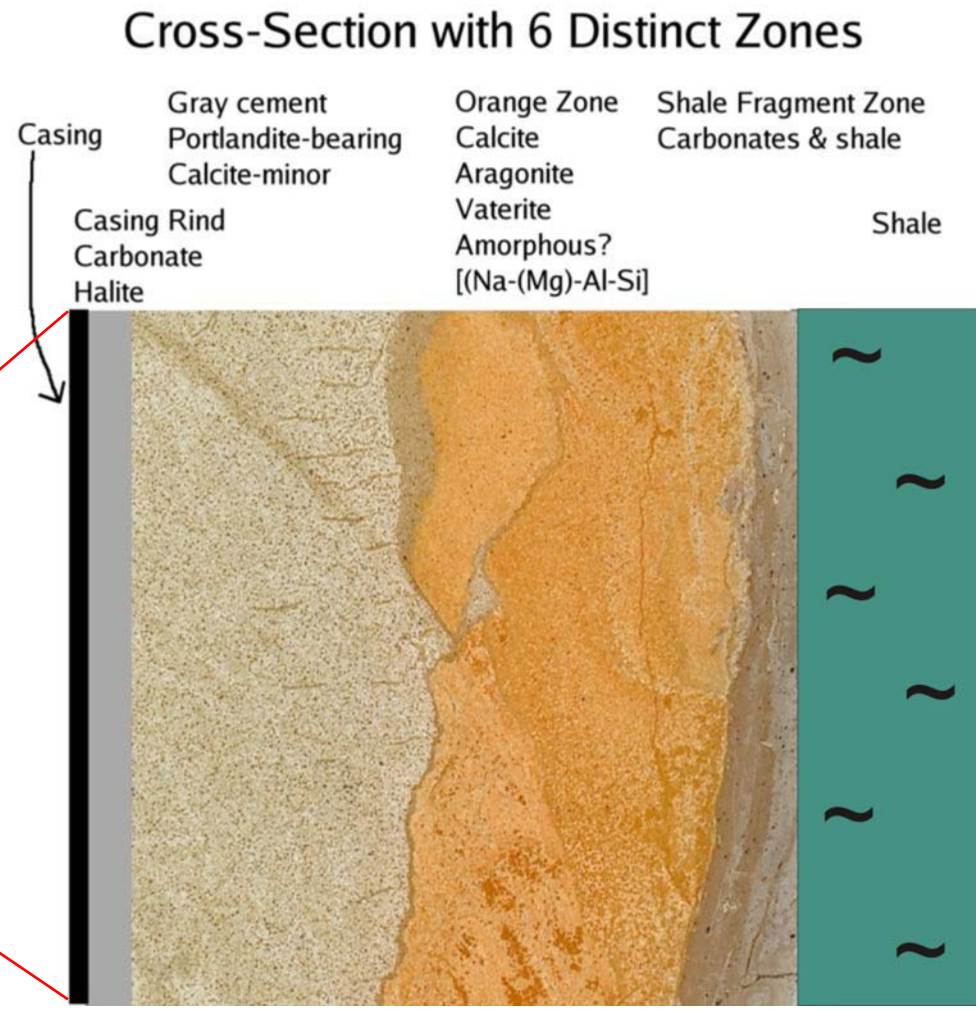
OUTLINE

- Introduction
- Batch experiments
- Core flood experiments
- Future projects

Wellbore integrity

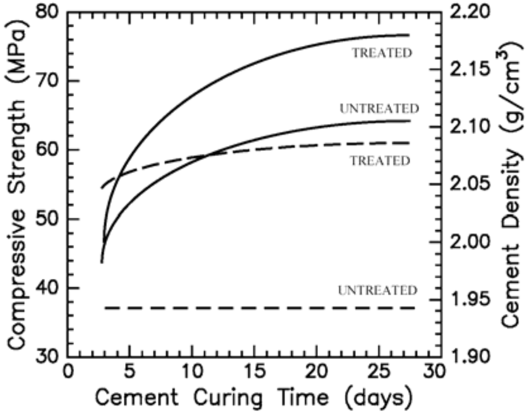


Wellbore image produced by F.B. Walton, LeNeveu Simulations Inc.



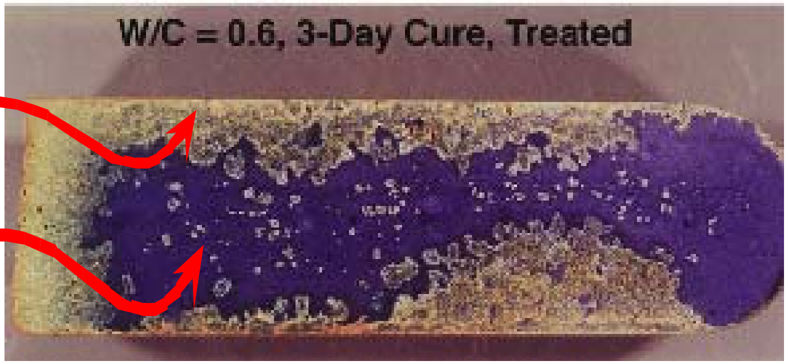
Batch experiments

- Rate of CO_2 diffusion
- Mineralogical and chemical changes
- Development/calibration of reactive transport codes
- Mechanical integrity
- Effect of water content/availability on extent of carbonation

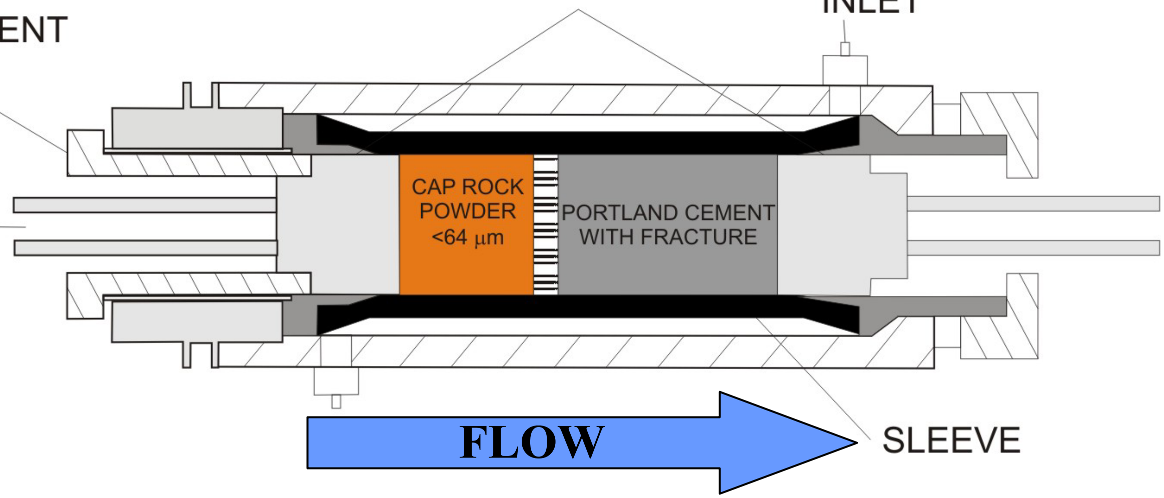


carbonated region

uncarbonated paste



Core flood studies of fractured wellbore cement in contact with the cap rock



<u>EXPERIMENTAL SETUP:</u>

Hassler vessel

Pore pressure 2880 psi

Confining pressure 3800 psi

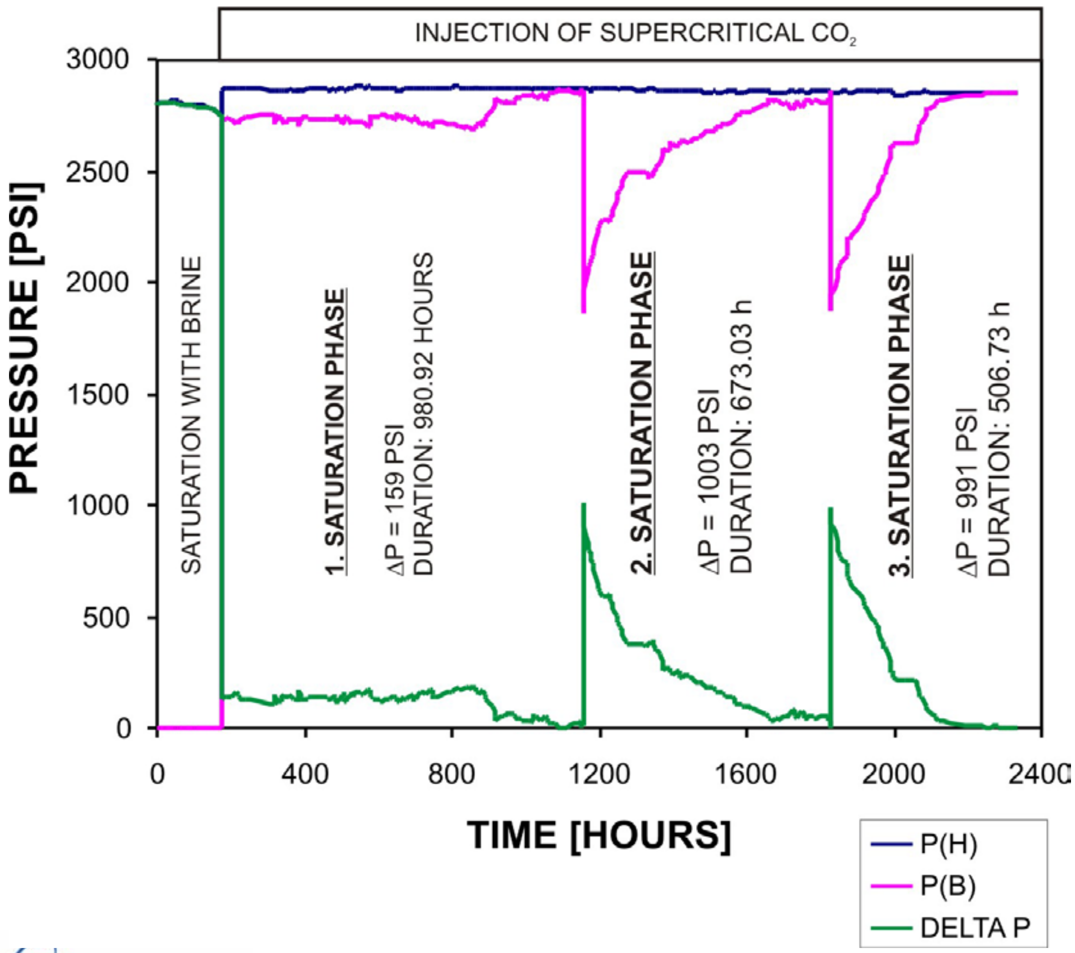
Temperature 54°C

<u>PROCEDURE</u>

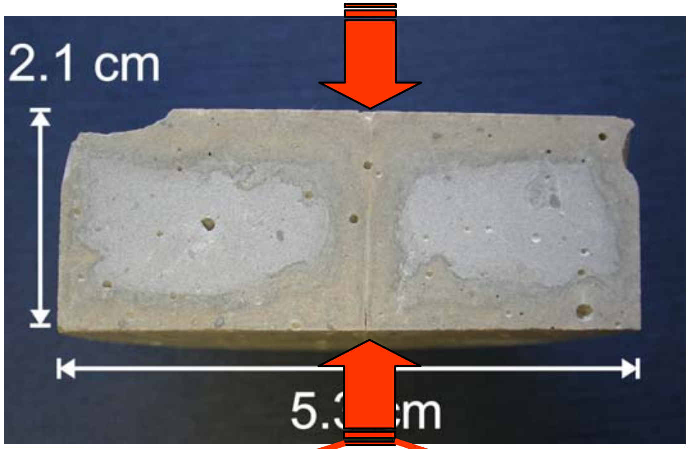
Saturation with 3 M brine over 174 hours

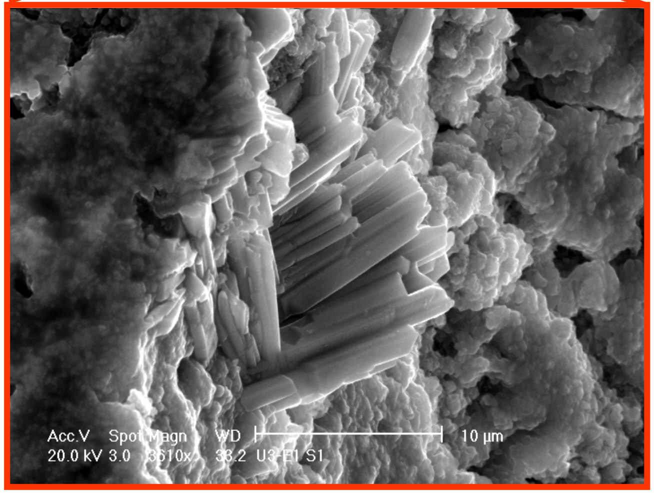
Injection of $SCCO_2$ over 2163 hours

Studies of fractured wellbore cement in contact with the cap rock

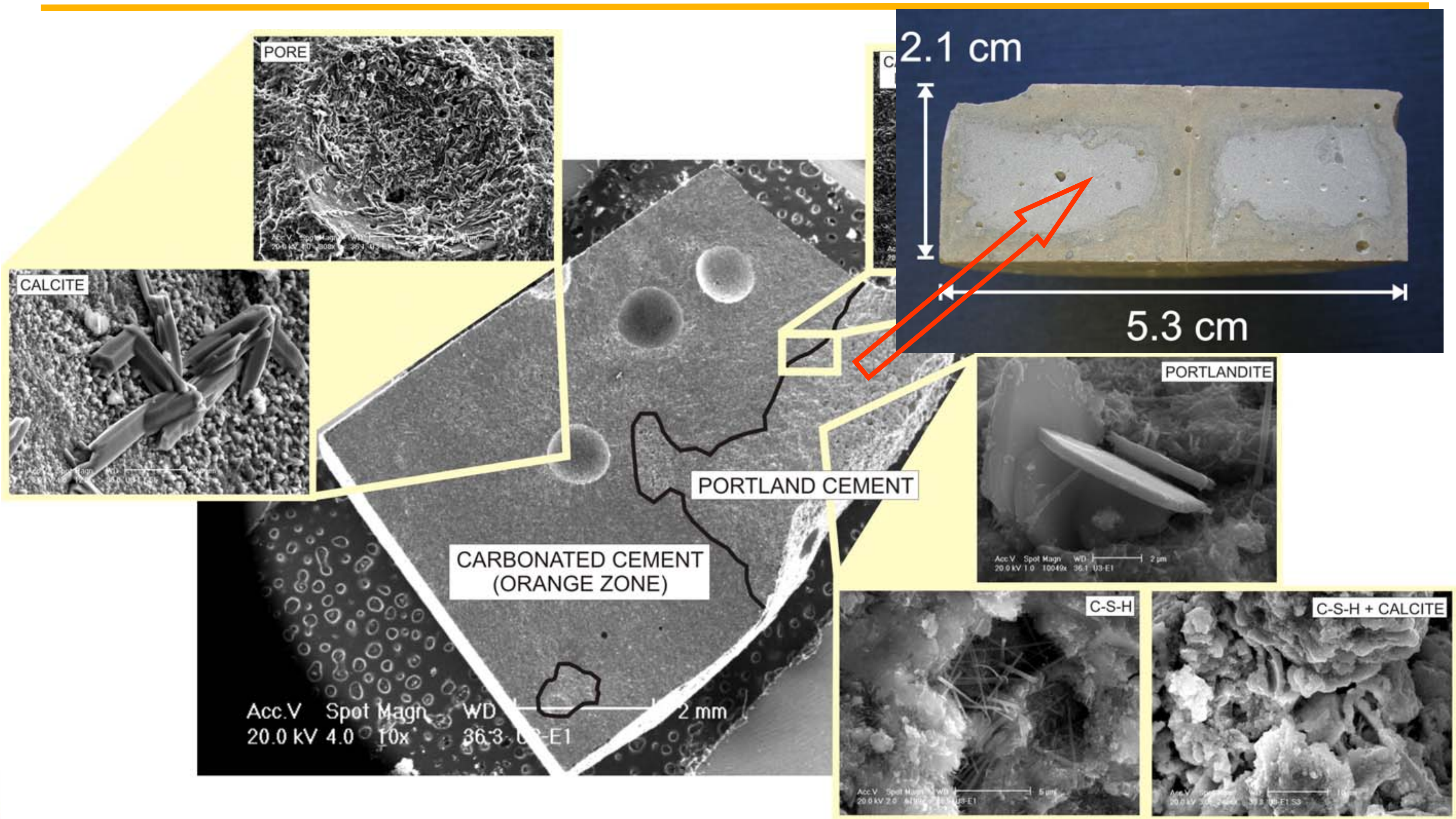


FRACTURE

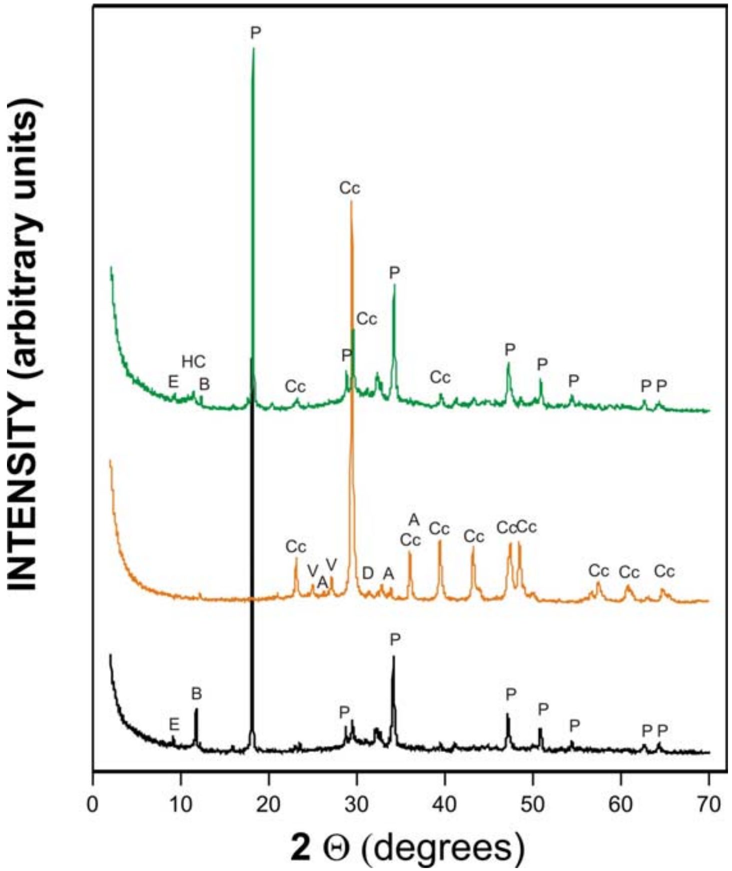




Geochemical reactions at the interface between cap rock and wellbore cement

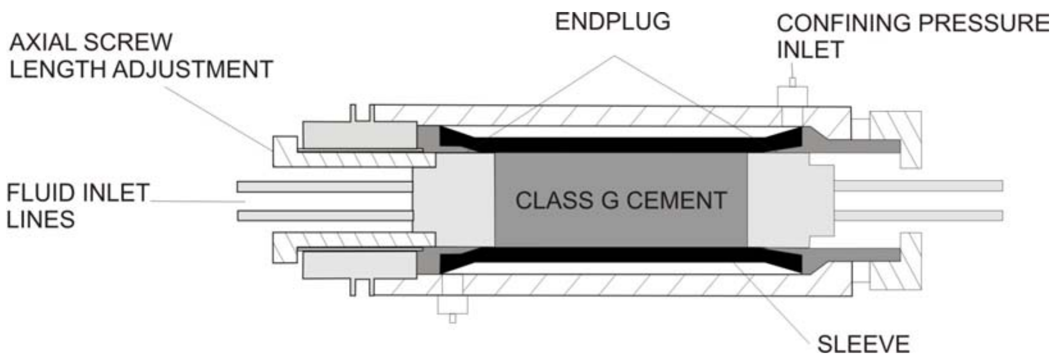


Geochemical reactions at the interface between cap rock and wellbore cement



	PORTLAND CEMENT (before)	ORANGE ZONE	PORTLAND CEMENT (after)
Portlandite	X		X
C_2S	X		X
C_3S	X		
C_4AF	X	X	X
Ettringite	X		X
C_3AH_6			X
Hydrocalumite			X
Calcite		X	X
Vaterite		X	
Aragonite		X	
Dolomite		X	

Geochemical reactions at the interface between "steel casing" and wellbore cement



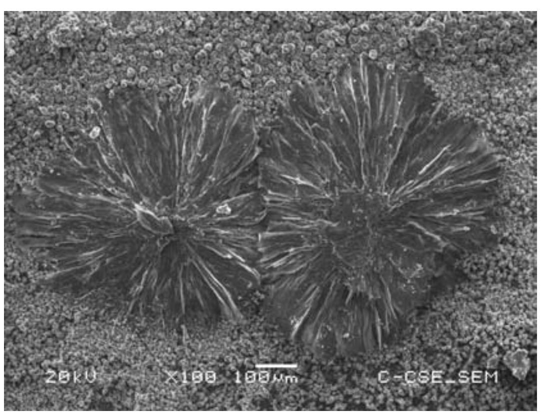
EXPERIMENTAL SETUP:

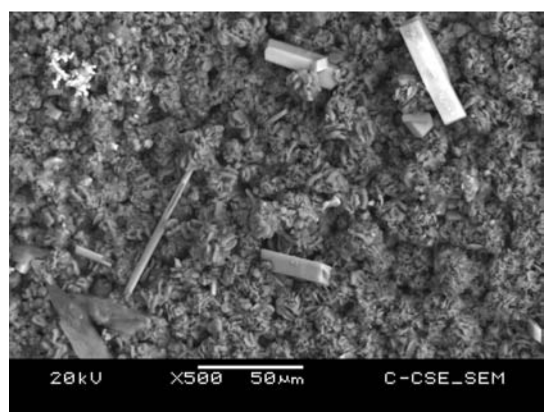
Pore pressure 2880 psi

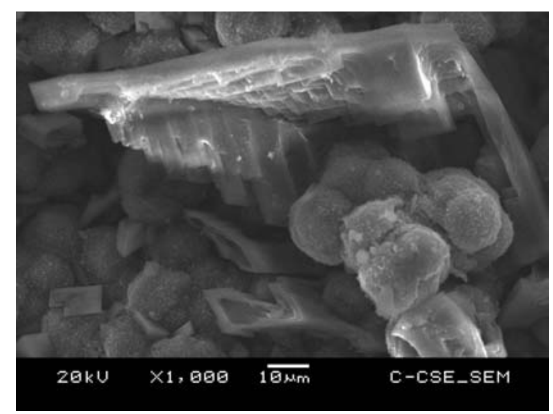
Confining pressure 3800 psi

Temperature 54^{o}C

Brine / $SCCO_2$ injection

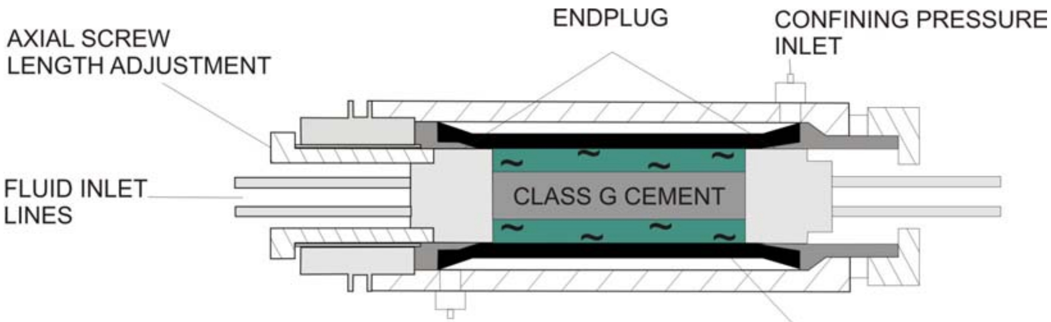






FUTURE WORK

Future Work: Study of micro-fractures at the interface between cap rock and wellbore cement



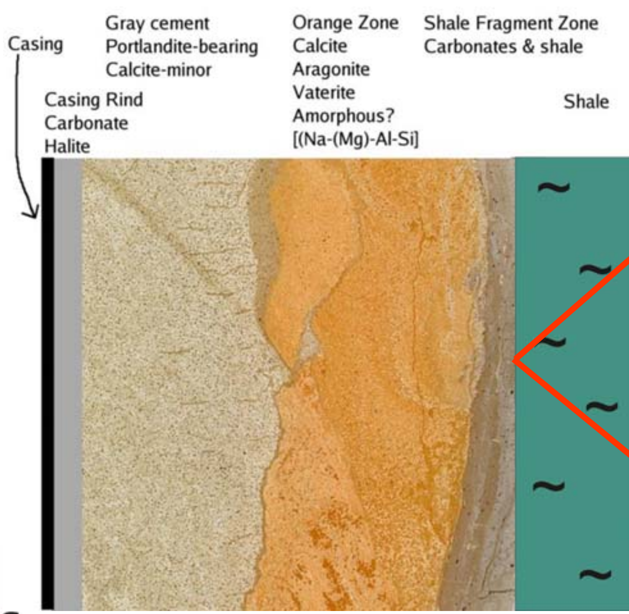
SETUP:

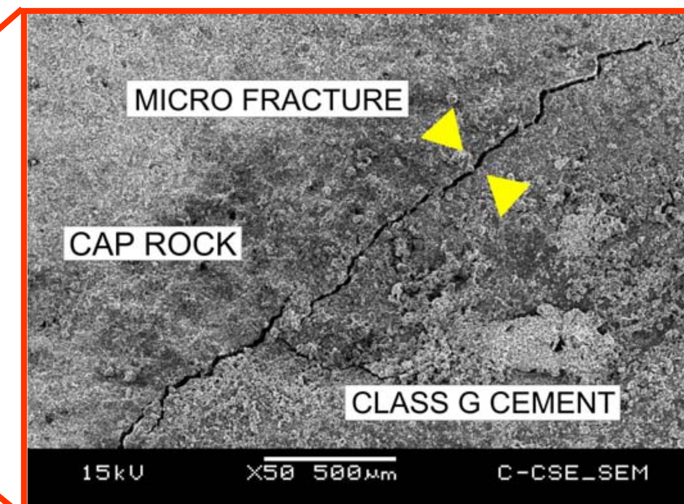
WAG or Co-injection of brine and $SCCO_2$

In-situ reservoir conditions

Monitoring the flow

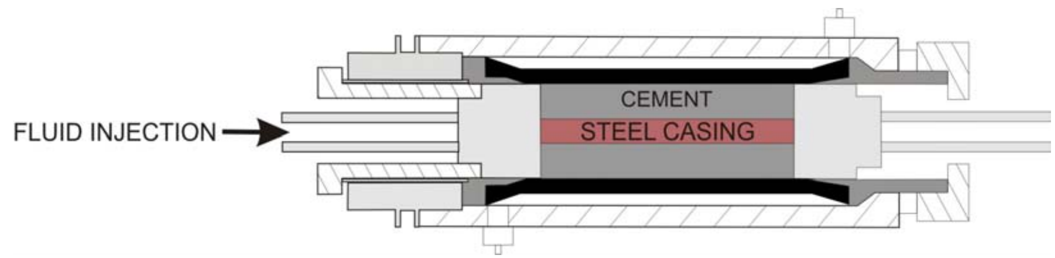
Cross-Section with 6 Distinct Zones



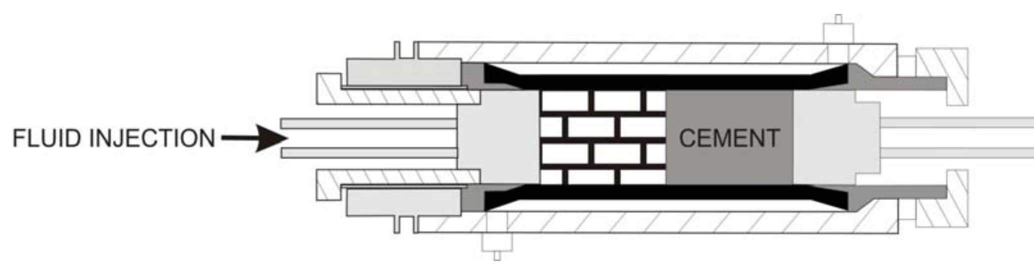


Future Work: Casing-Cement and Limestone-Cement Reactivity

Interface steel casing / wellbore cement



Interface reservoir rock / wellbore cement



Thank you very much for your attention !

Quantifying CO_2-related Alteration of Portland Cement

Experimental Approach and Microscopic Methodology

Gaëtan Rimmelé, Olivier Porcherie, Véronique Barlet-Gouédard, *Schlumberger*

Bruno Goffé, *Ecole Normale Supérieure, Paris*

2nd Well Bore Integrity Network Meeting
28–29 March 2006, Princeton University

Introduction

- Carbon Capture and Storage application requires long-term well bore integrity

- A major risk: CO_2 leakage through well bore annulus

  → major concern about cement isolation properties and durability

- Find appropriate cementitious material fulfilling isolation conditions

  → need a better understanding of Portland cement alteration processes <u>in CO_2 environment</u> and <u>under down hole conditions</u>

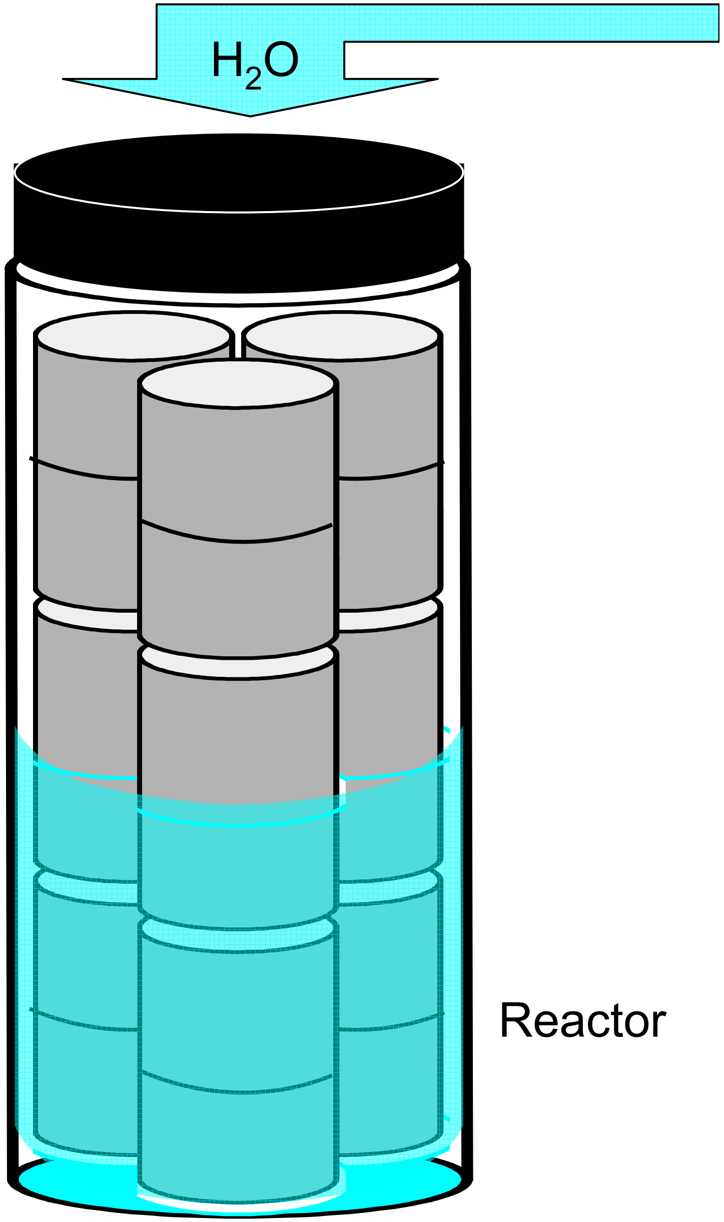
Experimental Approach and Microscopic Methodology

⬇

Chemical Cement-Sheath Integrity

Schlumberger

Experimental Procedure

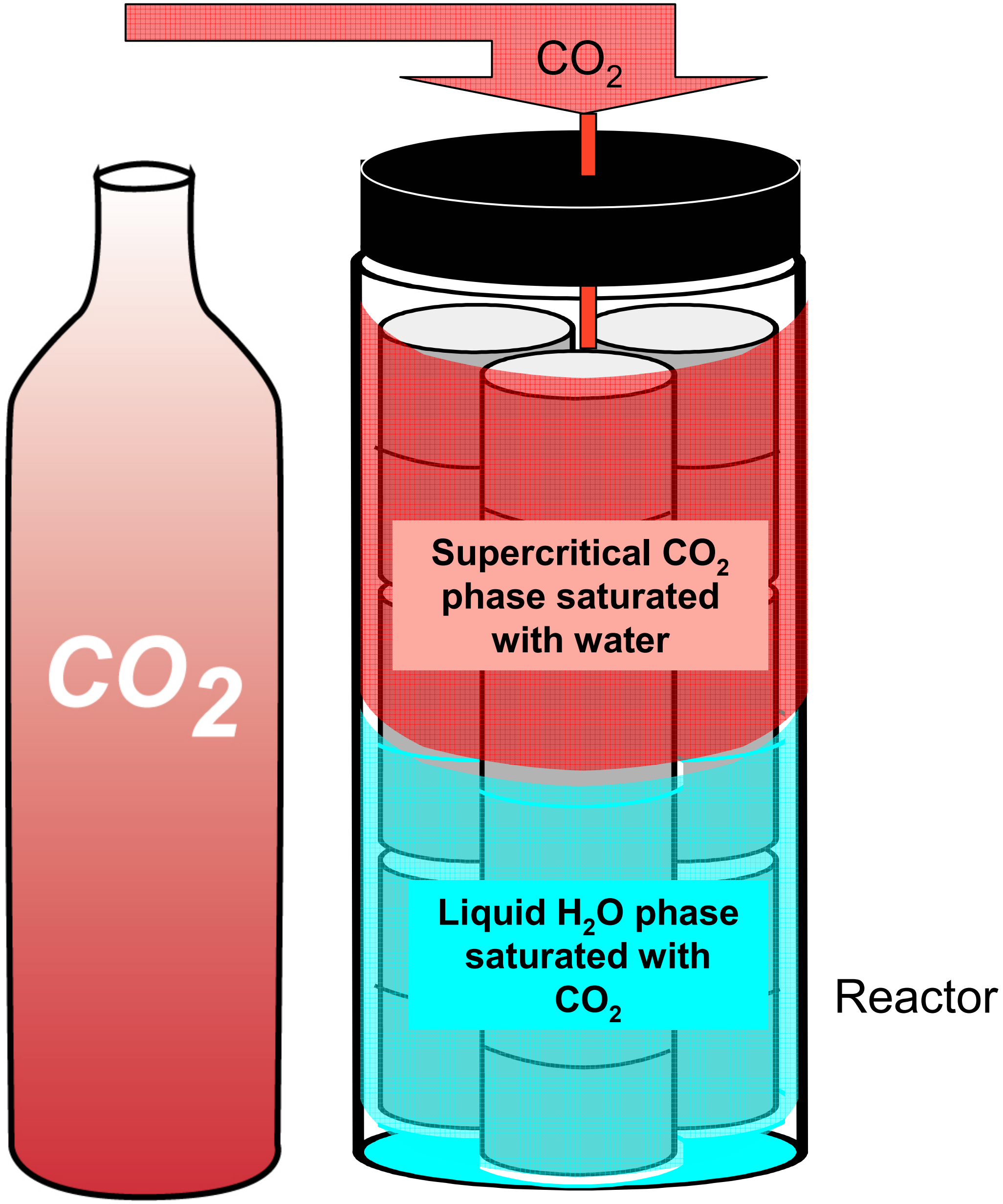


IADC/SPE 98924: Mitigation strategies for the risk of CO2 migration through wellbores
V.Barlet-Gouédard, G.Rimmelé, Schlumberger, B.Goffé, CNRS/ENS*, O.Porcherie, Schlumberger

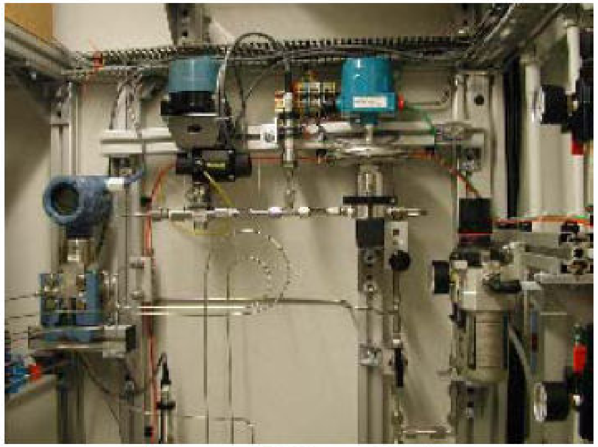
Experimental Procedure

→ Diphasic system

TEST CONDITIONS:
P=280 bars
T=90°C



Setup for CO2 Testing



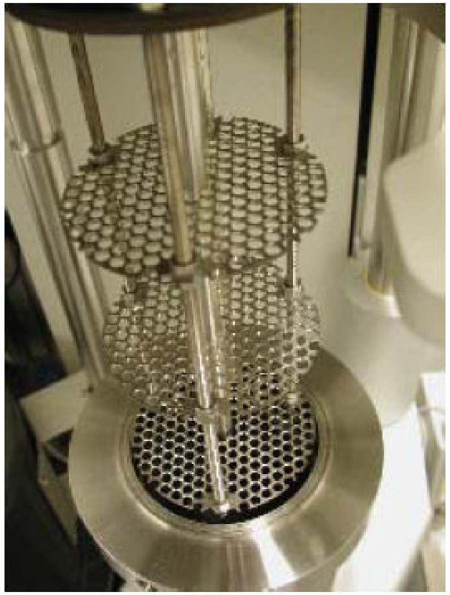
Pressure Release System

Controls and Electronics

Low and High Pressure CO2 Supply

Reactor (oven removed)

Reactor (oven in place)



Support for samples

Samples in place

SRPC - CO2 SETUP

How do we quantify cement alteration?

- Chemical and mineral composition of matrix before and after CO_2 attack:
  - Thickness of the alteration front
  - XRD analyses
  - SEM-EDS analyses

- Characterization and visualization of matrix porosity and/or permeability:
  - Mercury Intrusion Porosimetry measurements
  - SEM-BSE image analyses
  - Variation of %water loss versus square-root-of-time measurements

- Fluid analysis:
  - pH variation
  - Water production

- Evolution of physical properties before and after CO_2 attack :
  - Weight and dimensions variation measurements
  - Compressive strength measurements

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Carbonation of Portland Cement

Reactions involved

$$CO_2 + H_2O \rightarrow H_2CO_3 \rightarrow H^+ + HCO_3^-$$

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

$$C\text{-}S\text{-}H + H^+ + HCO_3^- \rightarrow CaCO_3 + \text{silica gel}$$

$$CaCO_3 + H^+ + HCO_3^- \rightarrow Ca(HCO_3)_2$$

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O$$

➘ $CaCO_3$ precipitation

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Carbonation of Portland Cement

Before attack | After 2 days | After 3 months

$CaCO_3$ precipitation → Calcite, aragonite, vaterite

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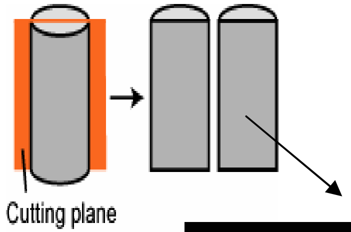
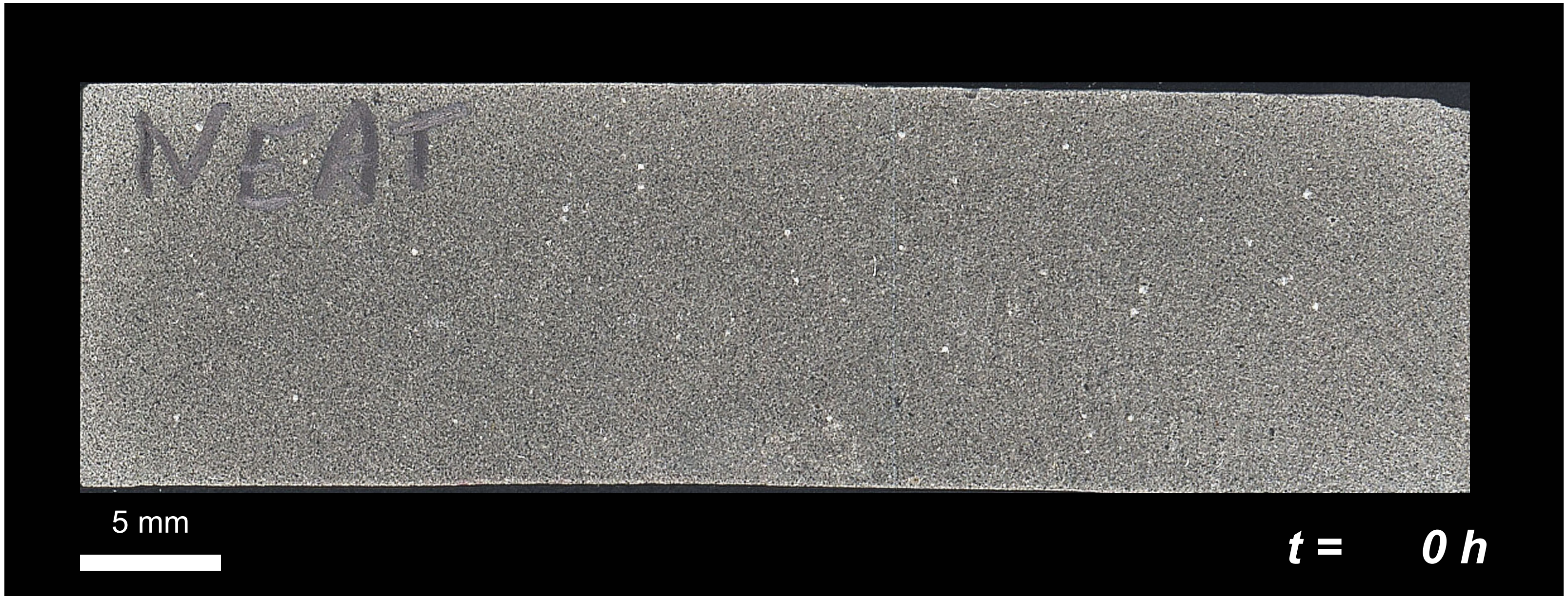
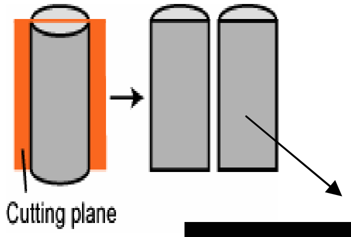
Alteration of Portland Cement

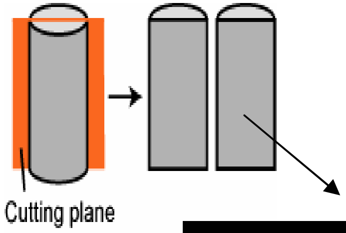




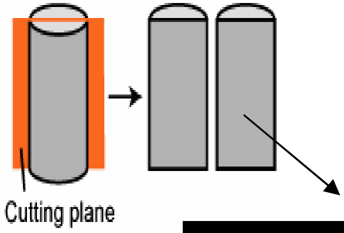
Alteration of Portland Cement

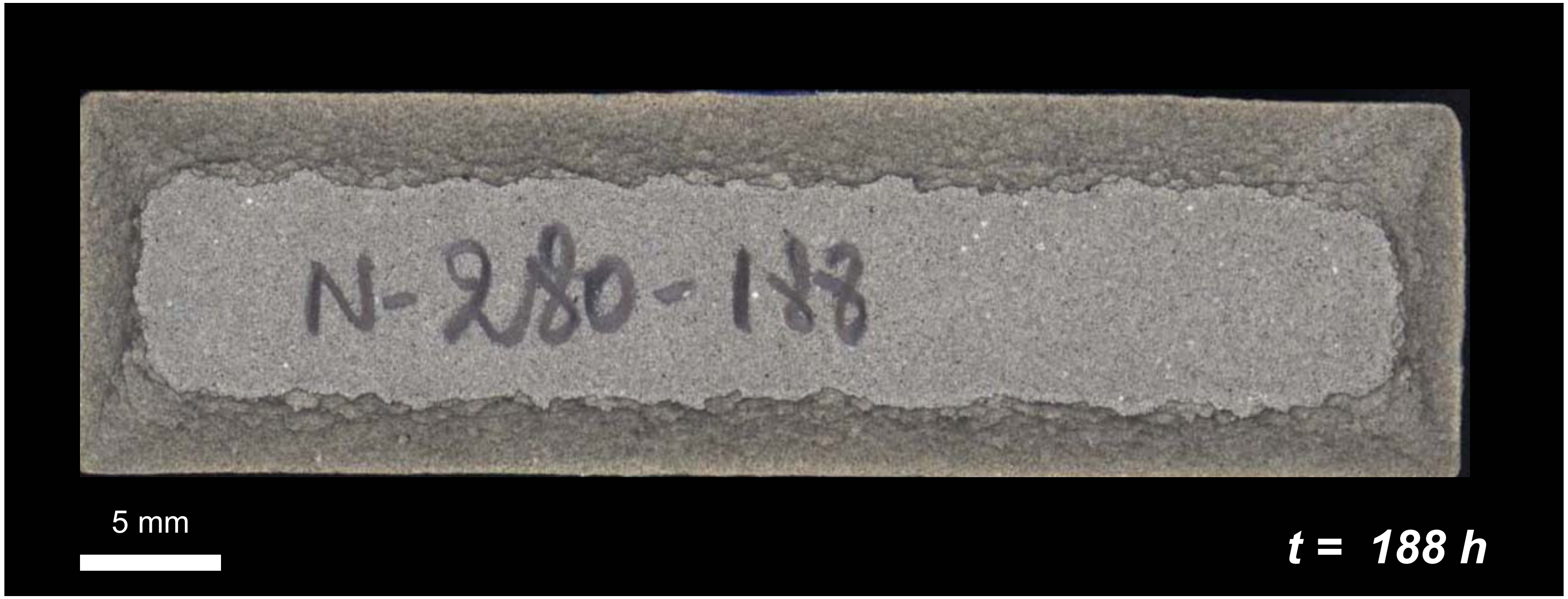


Alteration of Portland Cement

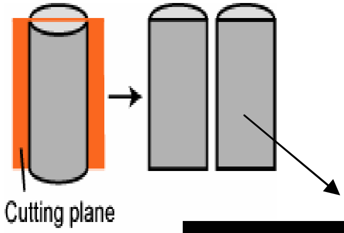


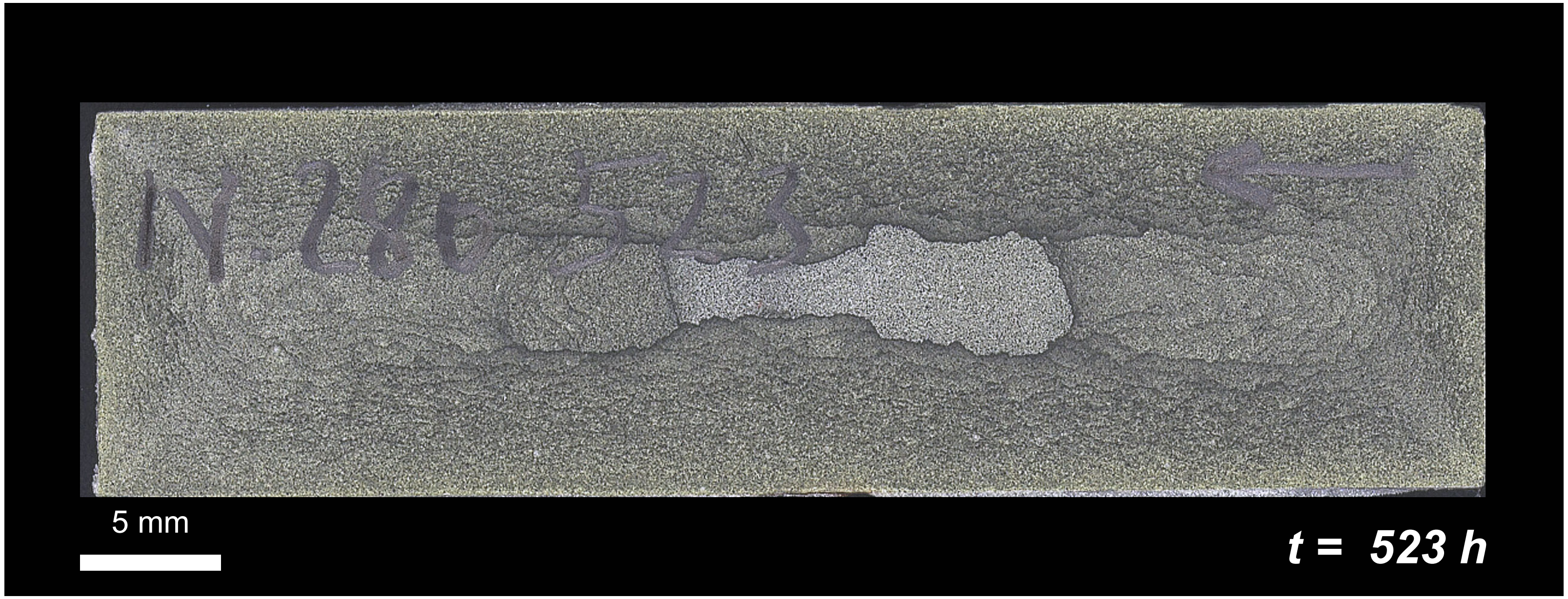
Alteration of Portland Cement



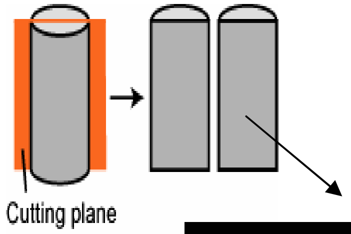


Alteration of Portland Cement





Alteration of Portland Cement



Complete carbonation after 6 weeks

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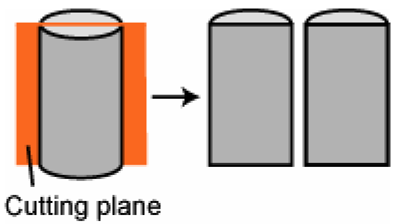
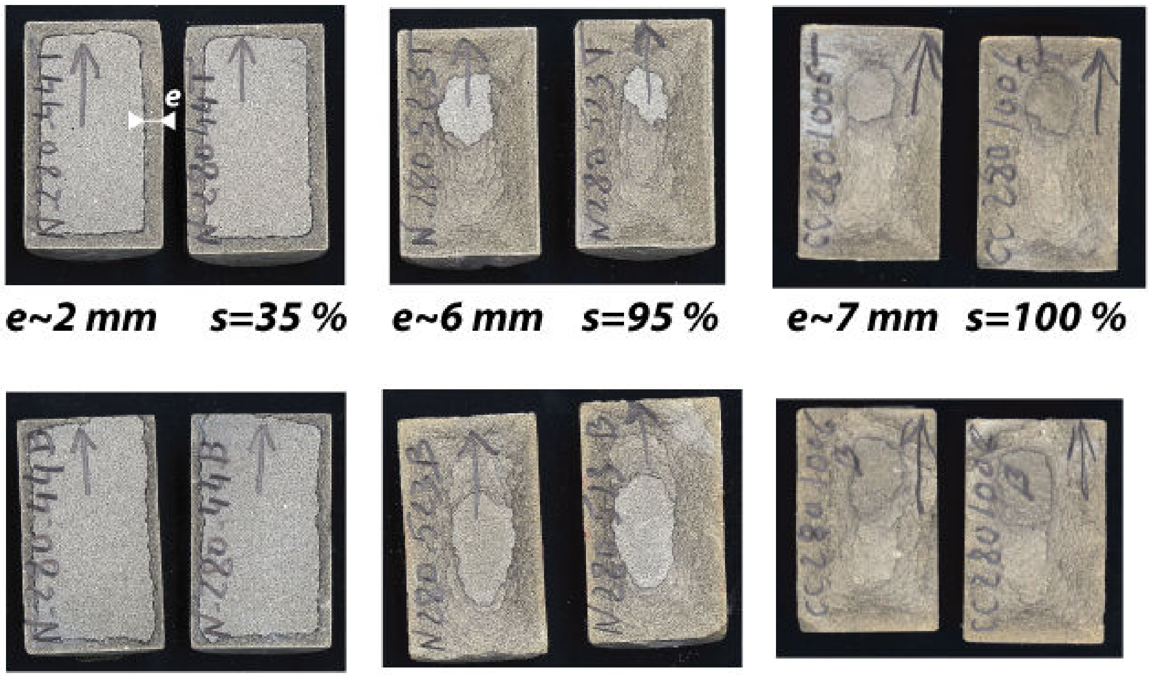
Evolution of the Alteration Front in both fluids





	44 h (~ 2 days)	523 h (~ 3 weeks)	1006 h (~ 6 weeks)
Wet supercritical CO_2	*e~2 mm s=35 %*	*e~6 mm s=95 %*	*e~7 mm s=100 %*
CO_2 saturated water	*e~1 mm s=23 %*	*e~5 mm s=84 %*	*e~7 mm s=100 %*

e : thickness of the alteration front

s : ratio between the alteration front surface and the whole core surface

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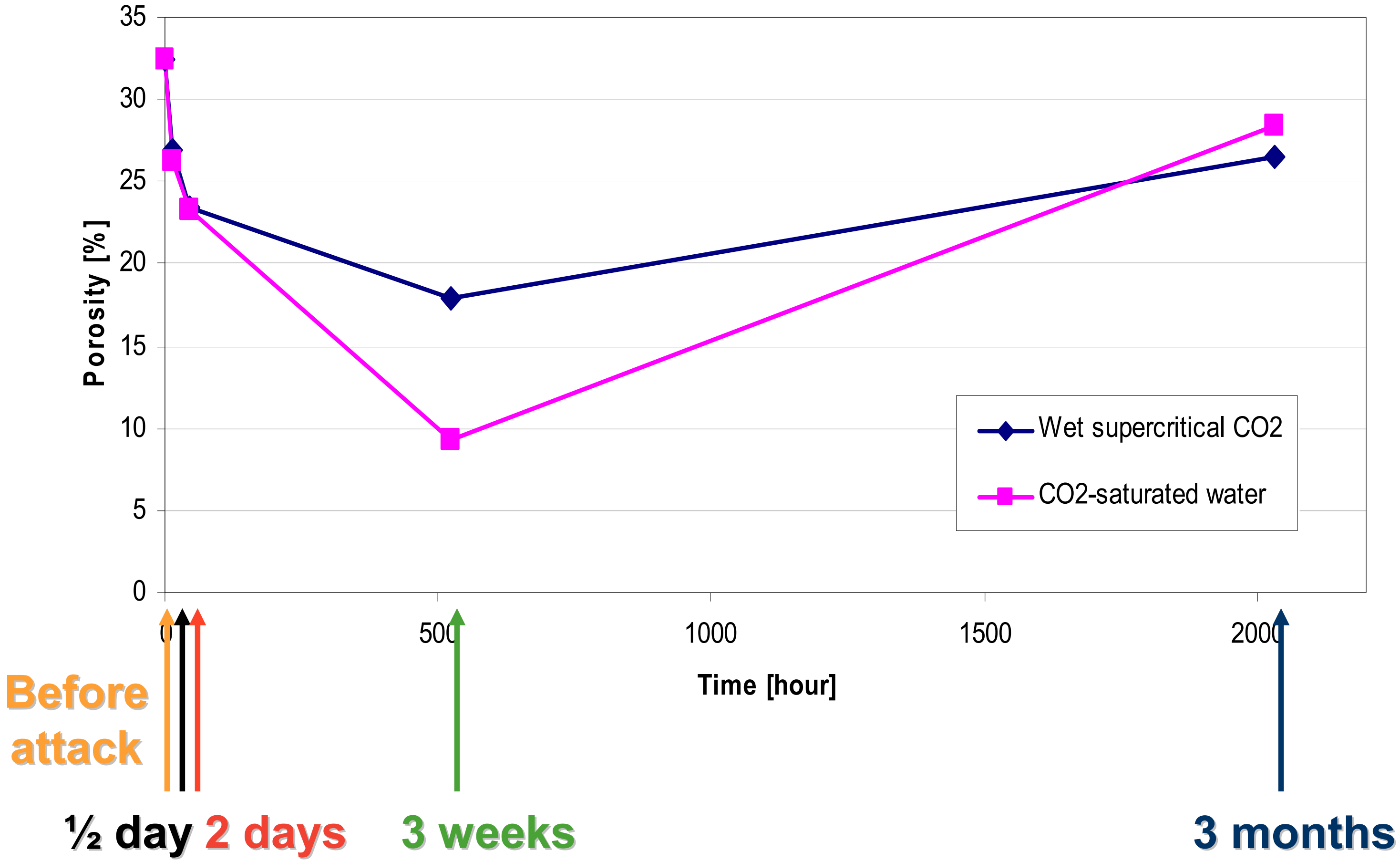
Mercury Intrusion Porosimetry



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Microstructural characterization and analyses

→ SEM observations

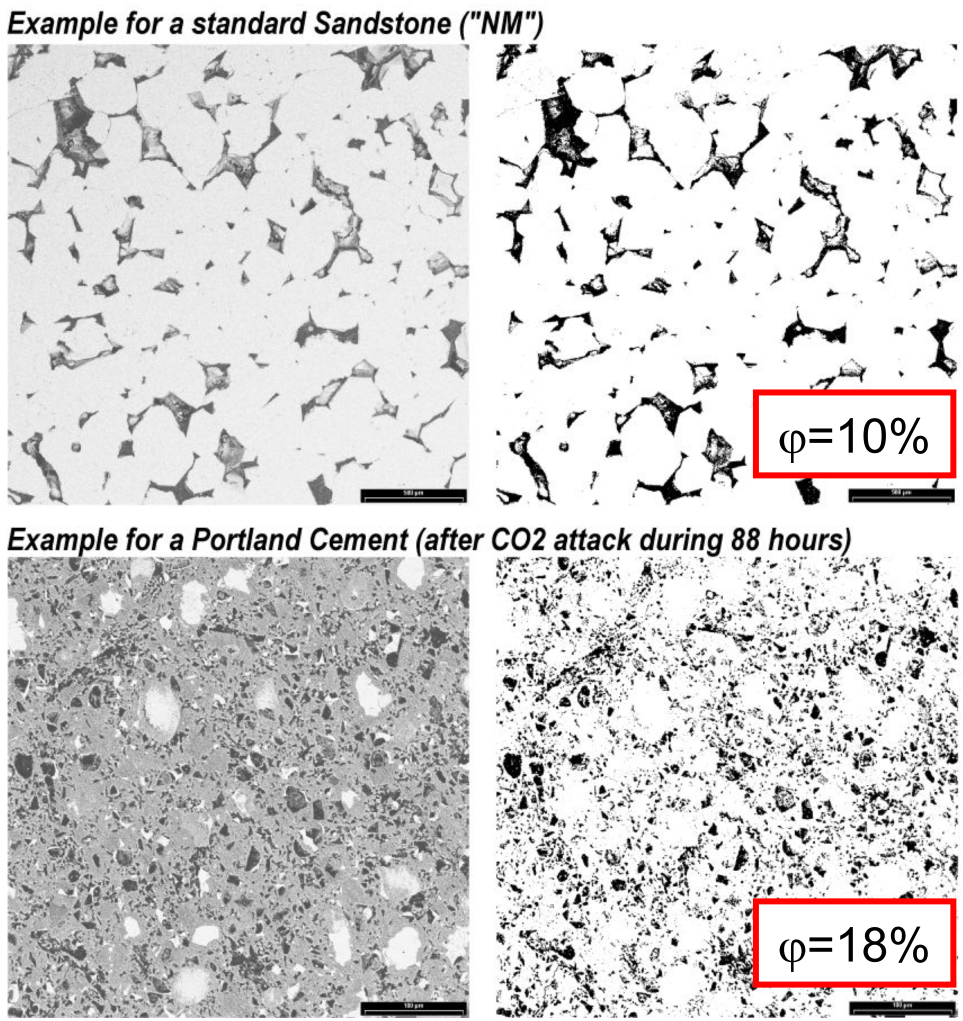
→ Local chemical profiles
(Quantitative EDS device)

→ Local porosity profiles
(BSE image analysis)

- Binarization of initial grey-scale SEM-BSE images

- Measurement of proportion of the black part

Relative local porosity



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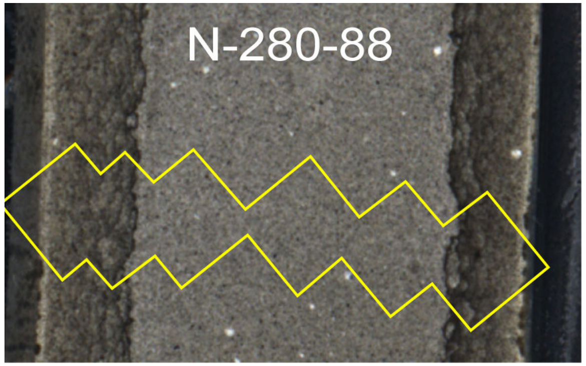
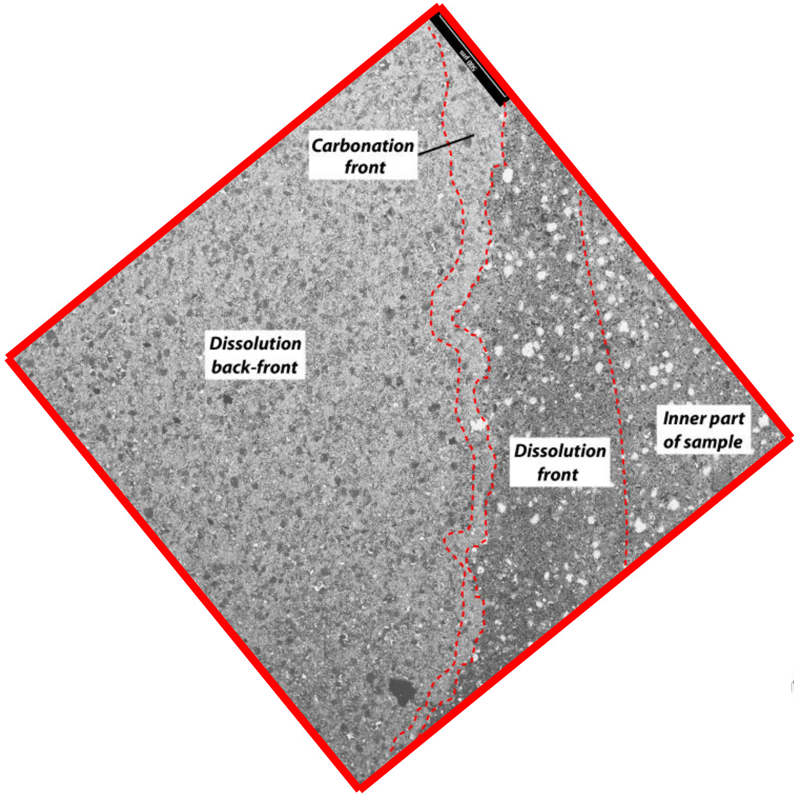
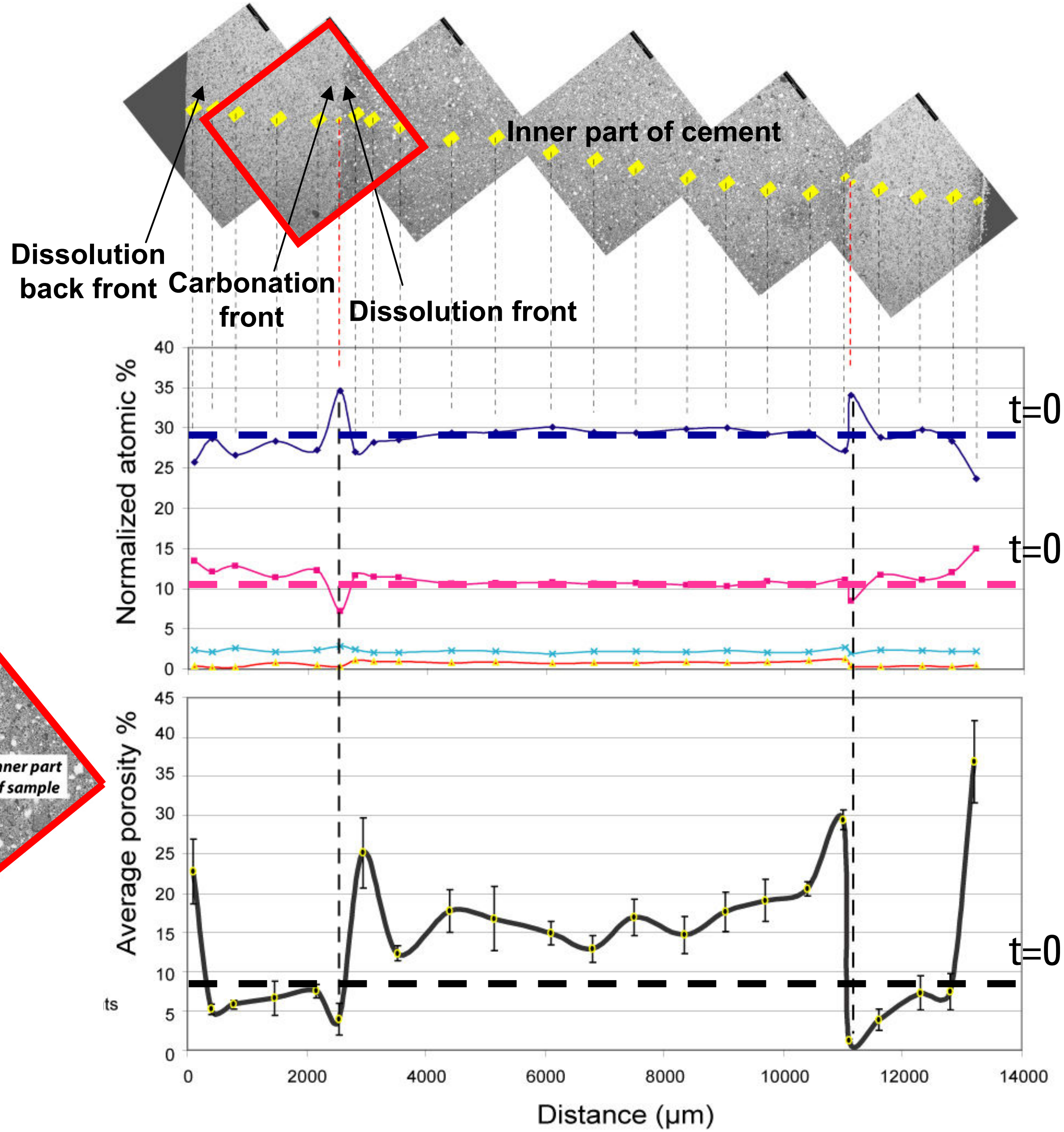
Microstructural characterization and analyses

4 days of CO_2-attack

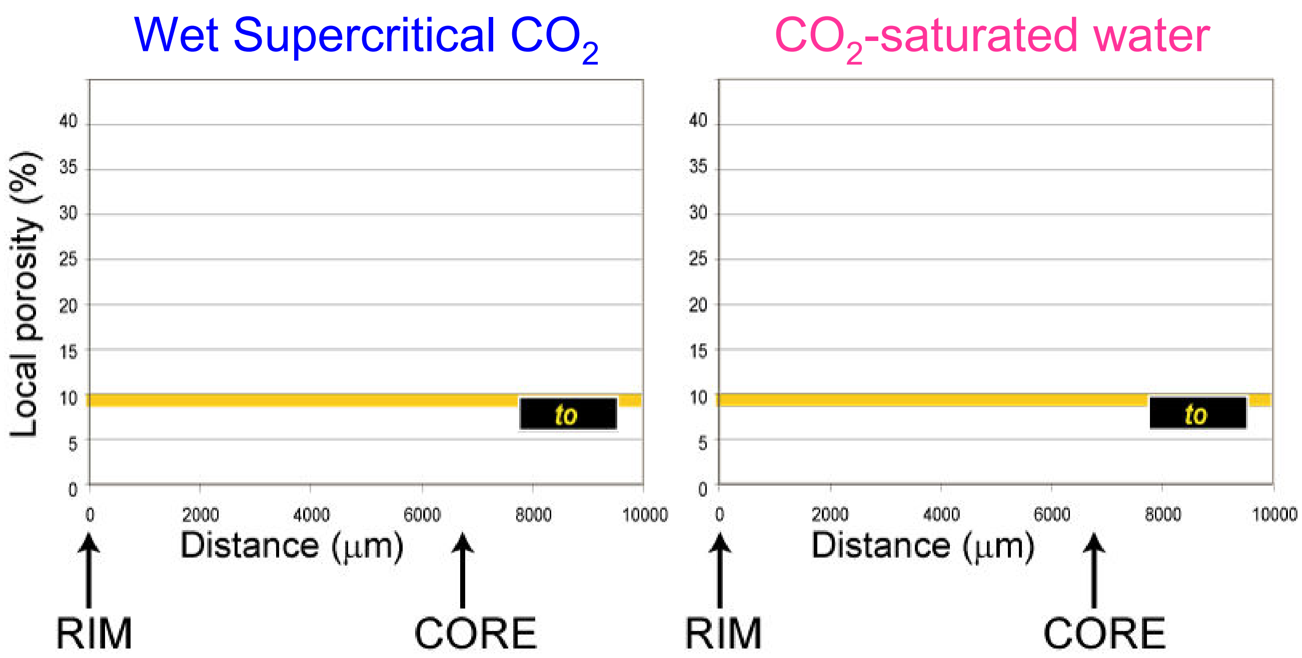






Local Porosity Profiles

Before CO_2 attack



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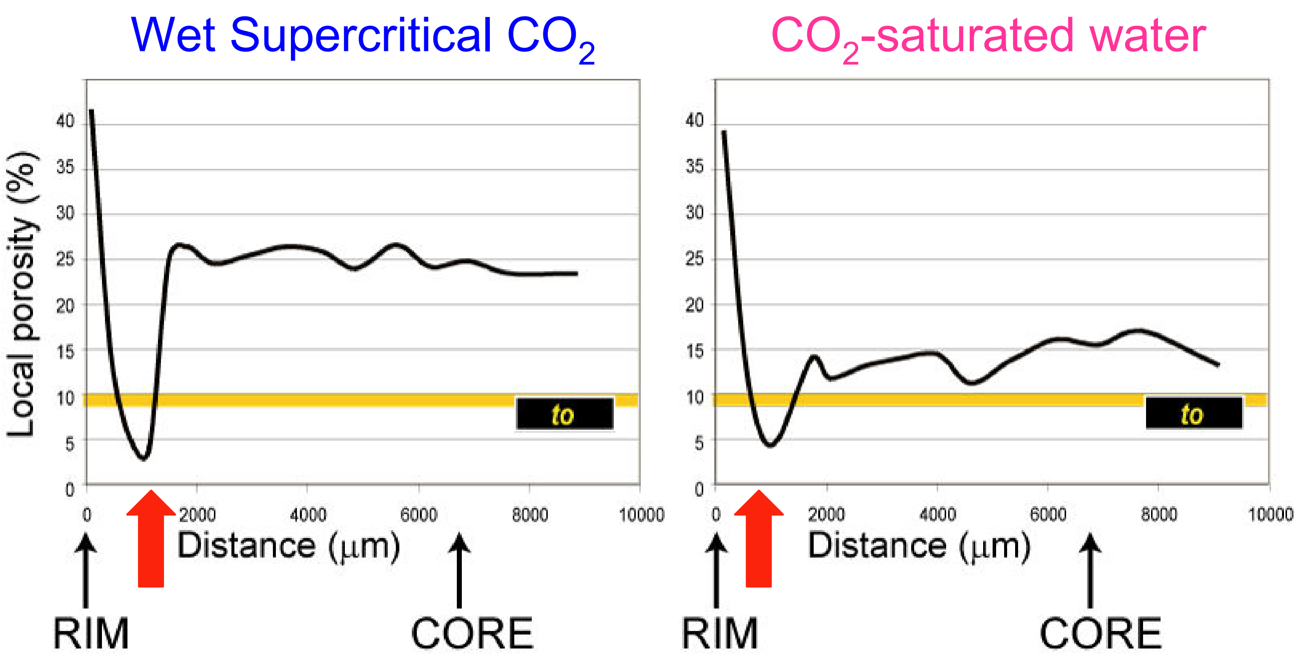
Local Porosity Profiles

After ½ day



Carbonation front

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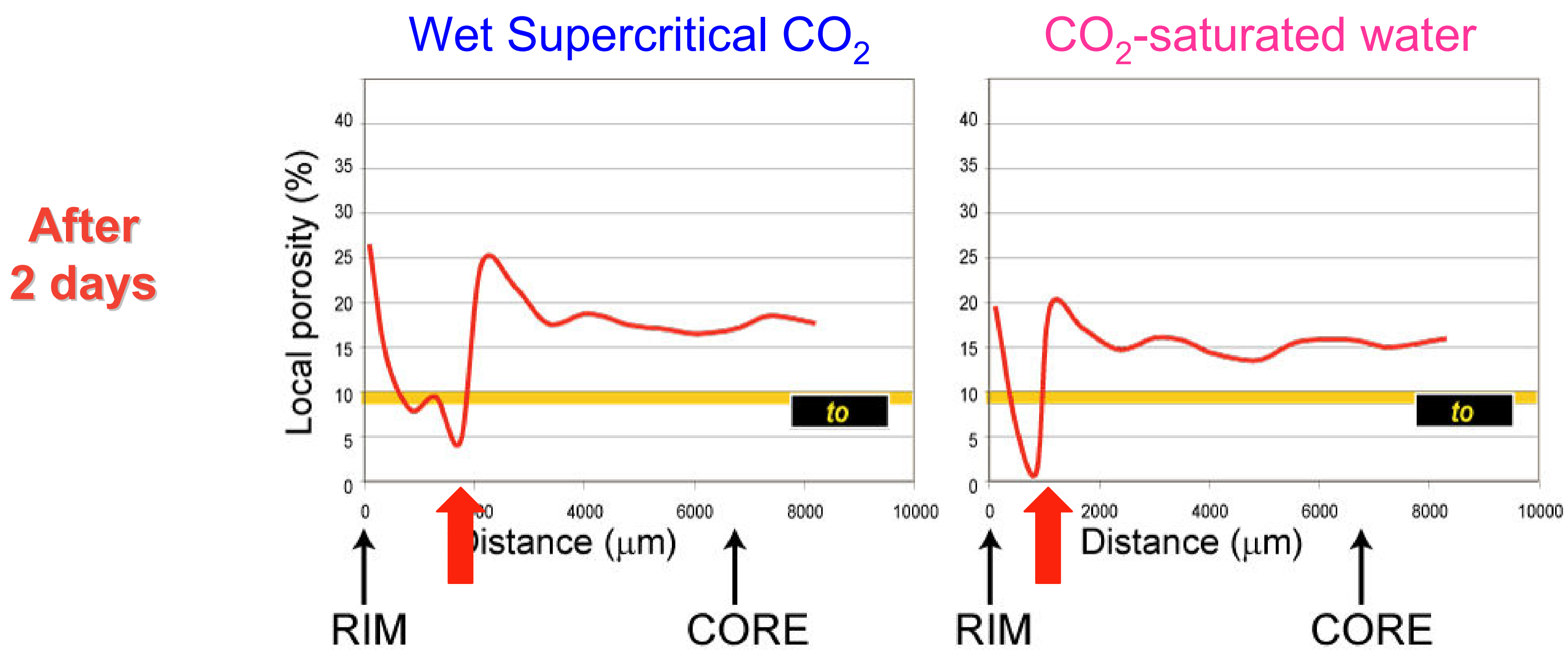
Local Porosity Profiles

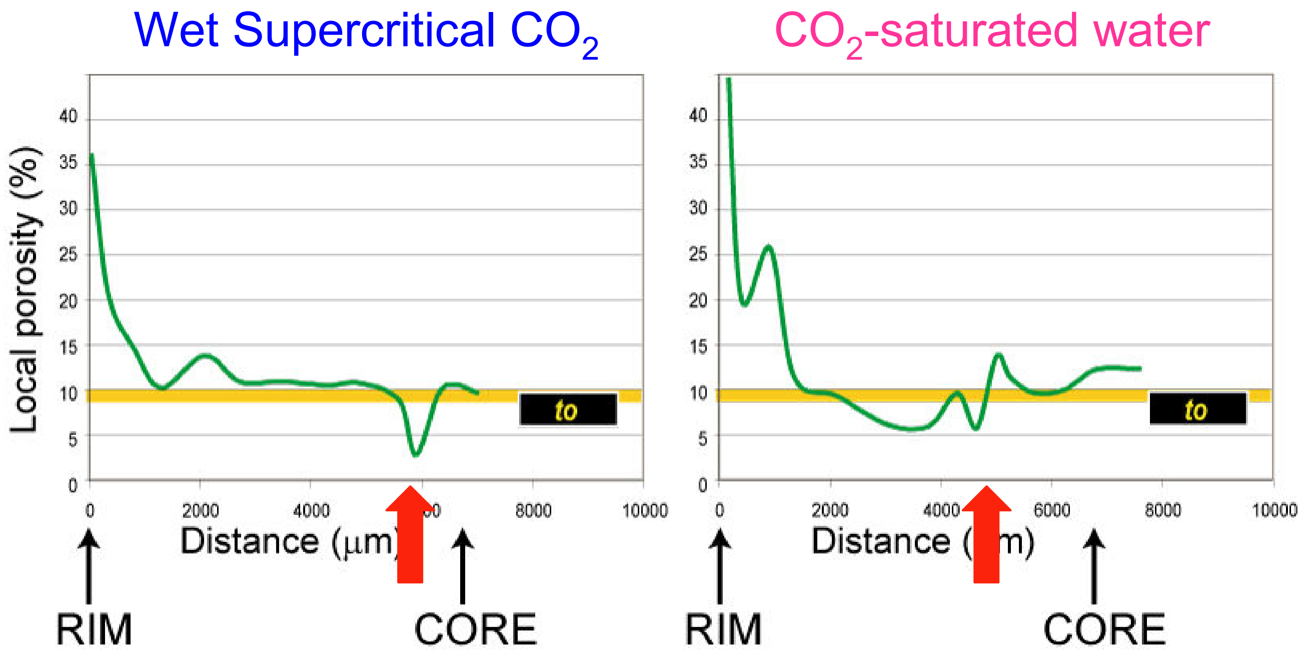


Carbonation front

Schlumberger

Local Porosity Profiles

After 3 weeks

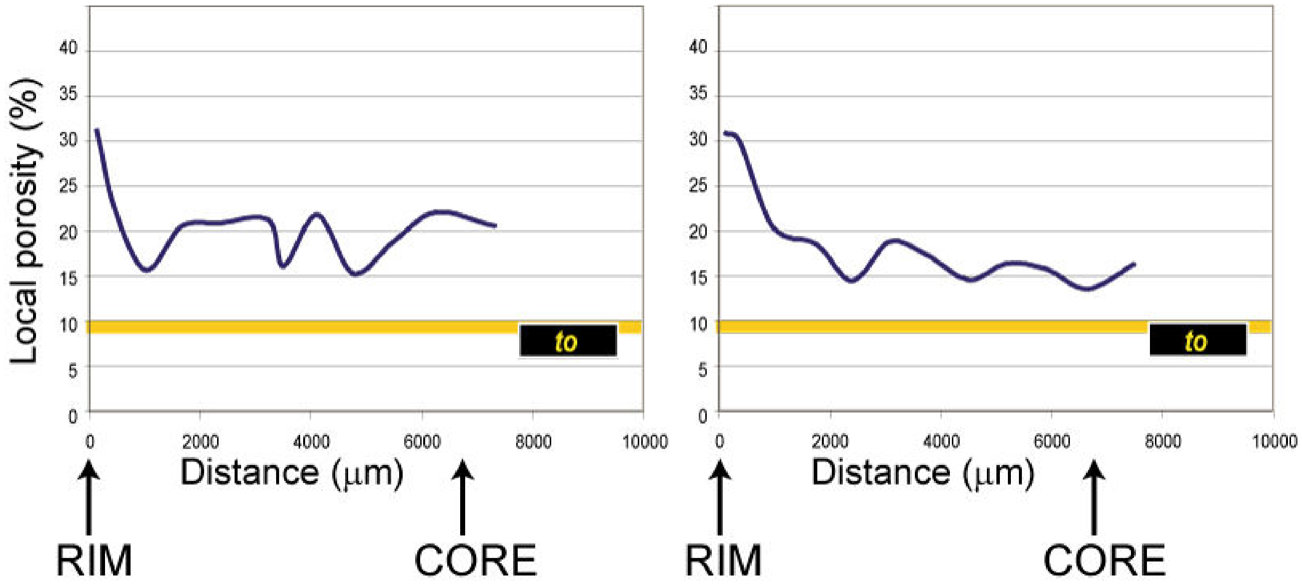


Carbonation front

Local Porosity Profiles

After 3 months

Wet Supercritical CO_2 | CO_2-saturated water



Complete carbonation

Carbonation front

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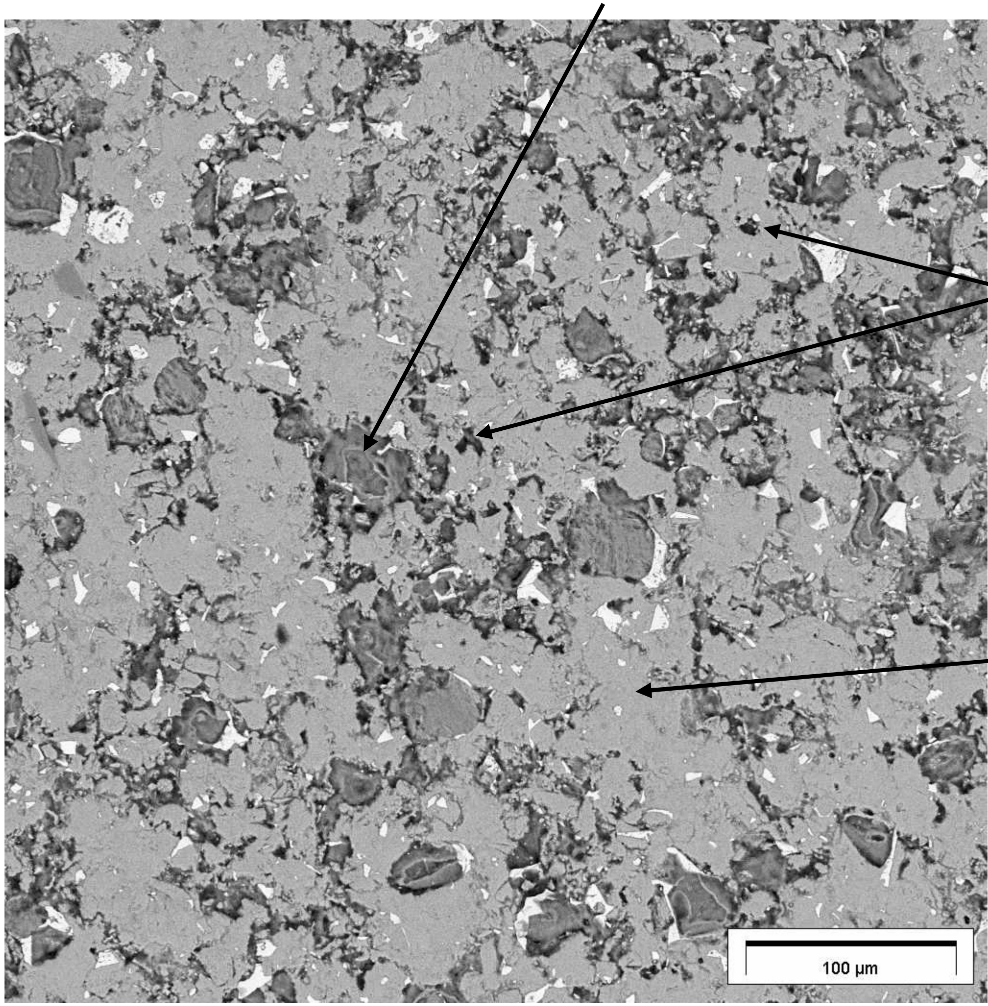
Local Porosity Profiles

After
3 months



SEM-BSE image

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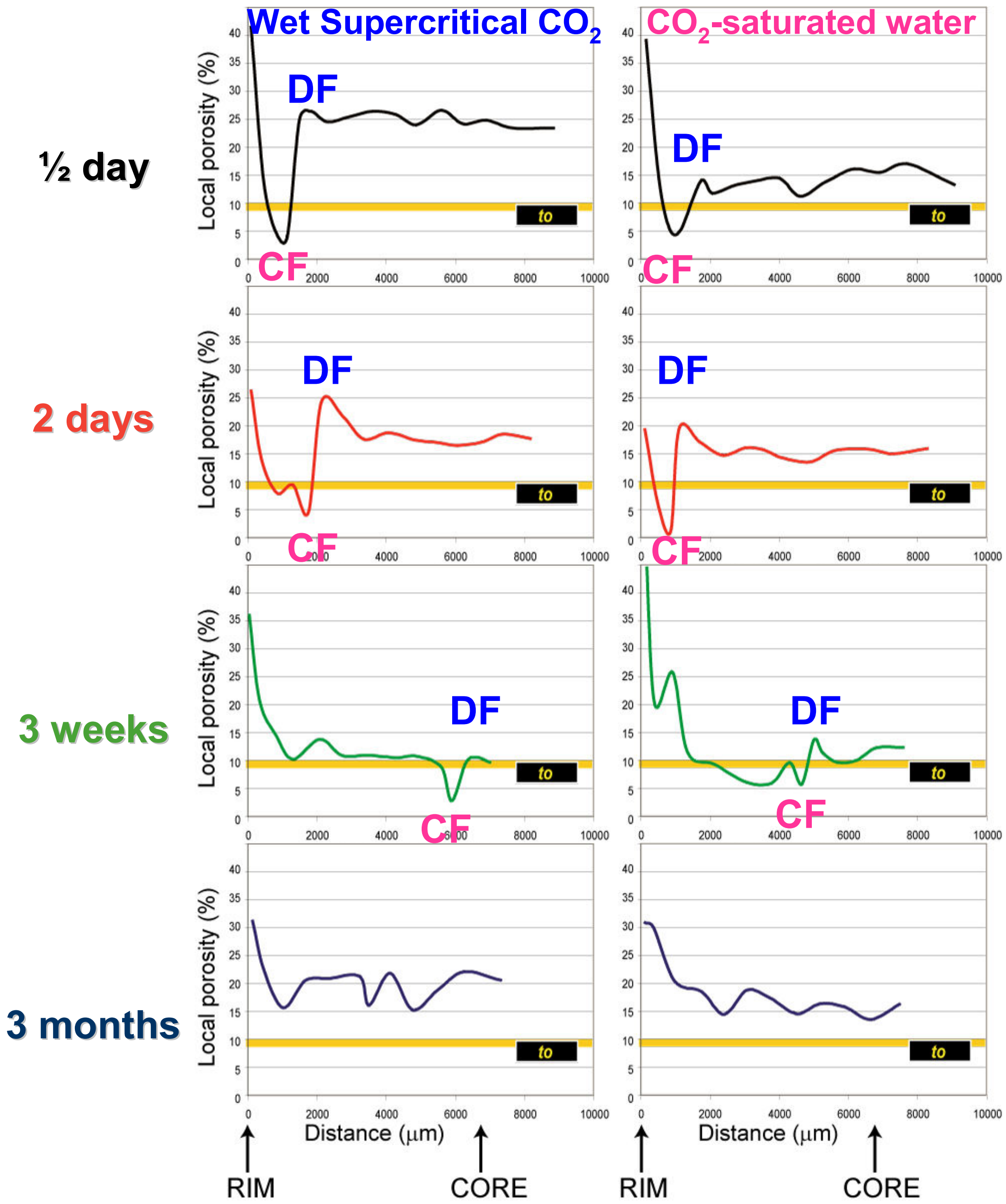
Local Porosity Profiles

- Translation of the carbonation front (**CF**) and dissolution front (**DF**) towards the core of samples

- φ(inner part) decreases: φ filled by neoformed carbonates

- Complete carbonation
- Increase of φ: dissolution of neo-formed carbonates or/and CSH?



Conclusion

- Alteration of Portland cement:

  - efficient process in both CO_2 fluids
  - complex series of fronts in both CO_2 fluids → favours its degradation

- Evolution of porosity by MIP measurements → total porosity of cement
  by BSE image analyses → local porosity through samples

  (1) very fast (first hours) dissolution of $Ca(OH)_2$ throughout the whole sample
  (2) sealing stage by carbonation
  (3) dissolution stage (increase of the global porosity after 3 months of attack)

  → carbonation does not continuously plug Portland cement

- Requirement of a new CO_2 resistant system

➔ Véronique Barlet-Gouédard's presentation!

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Degradation of Well Cement Under Geologic Sequestration Conditions

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

[1]U. S. Department of Energy
National Energy Technology Laboratory

[2]Carnegie Mellon University

Wellbore Integrity Network Meeting
March 29, 2006

Why should we be concerned about existing wellbore integrity?

- Over 360,000 active oil/gas wells registered with the Railroad Commission of Texas
- Estimated 1.5 million total deep holes in state of Texas (over 5 wells per square mile)

Degradation of Well Cement Under Geologic Sequestration Conditions

Objective:

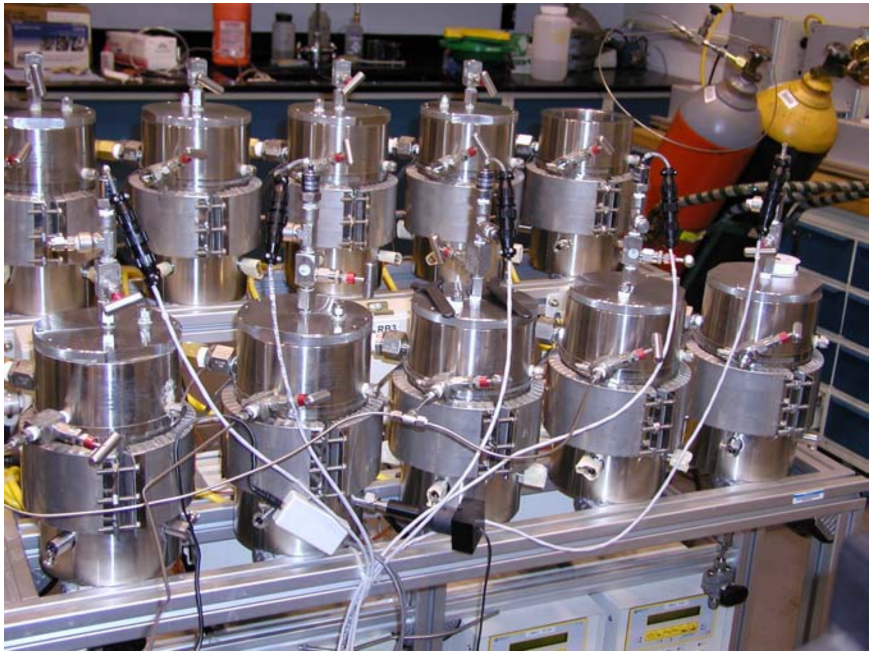
To determine the effect of exposure to CO_2 on the physical and chemical properties of cements under geologic sequestration conditions.

- **How does degradation depend on conditions?**
  - Temperature
  - Pressure
  - Salinity

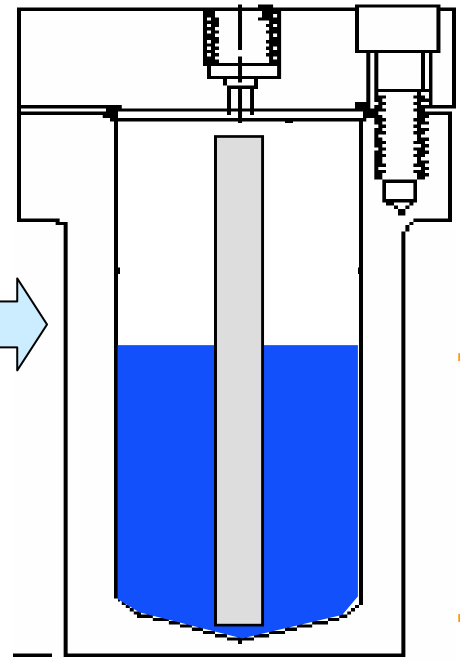
Cement Cure Conditions

- **Class H**
  - Prepared according to API Recommended Practice 10B
  - Hydrated for 28 days submerged in 1%NaCl solution

T = 50°C **P = 4400 psi** ***1300 m**	**T = Ambient** **P = 4400 psi**
T = 50°C **P = Atmospheric**	**T = Ambient** **P = Atmospheric**



CO_2 - Sequestration Exposure Experiments



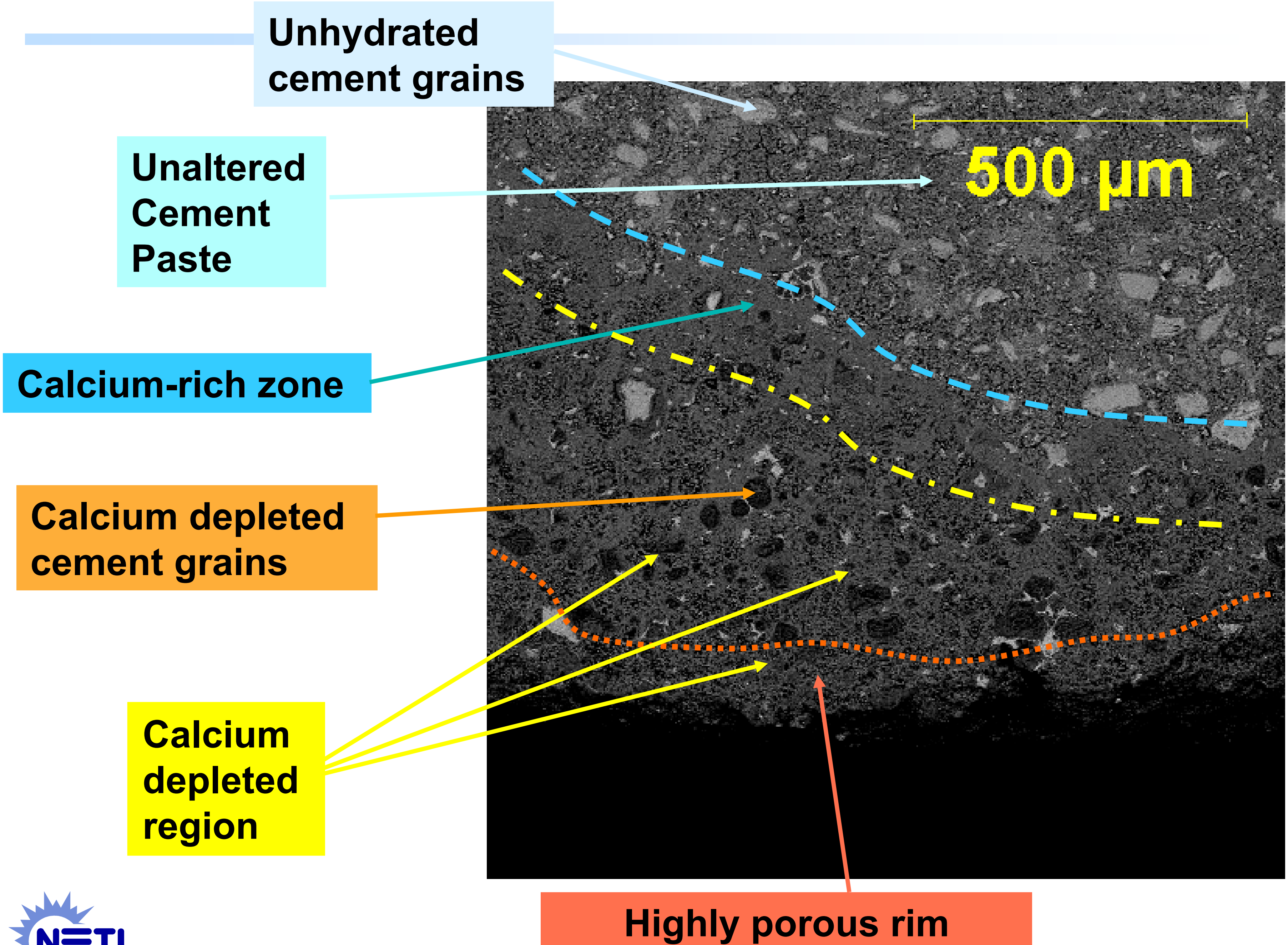
Headspace: water saturated CO_2

Aqueous phase saturated with CO_2

Results – Class H Neat

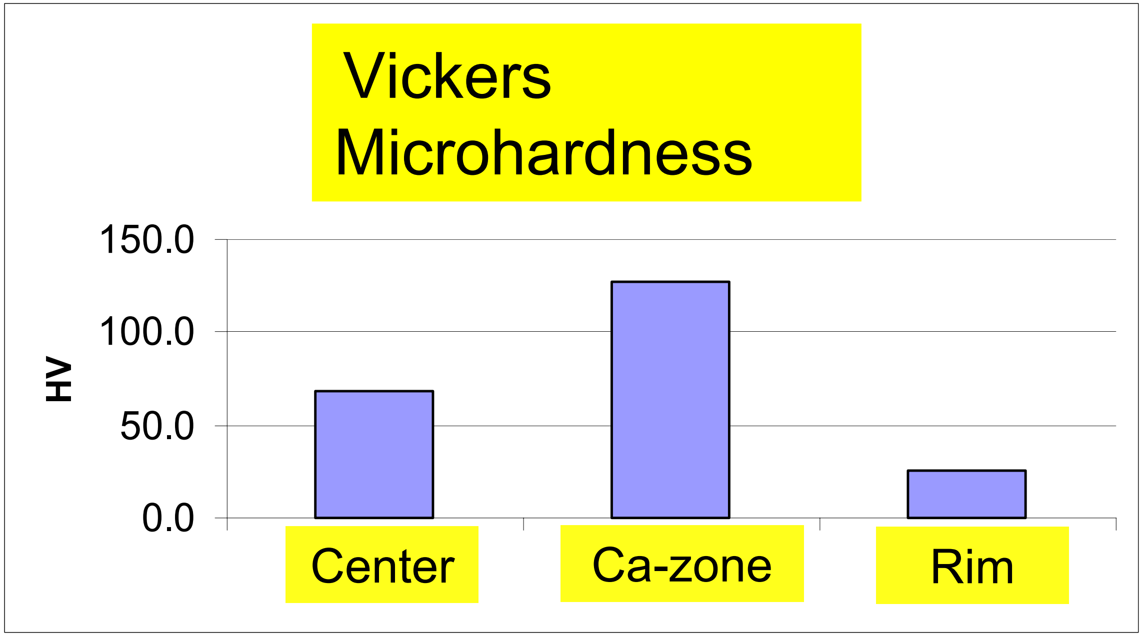
- **Top (Headspace: water saturated CO_2)**
  - Visible grey on surface
  - Rough texture

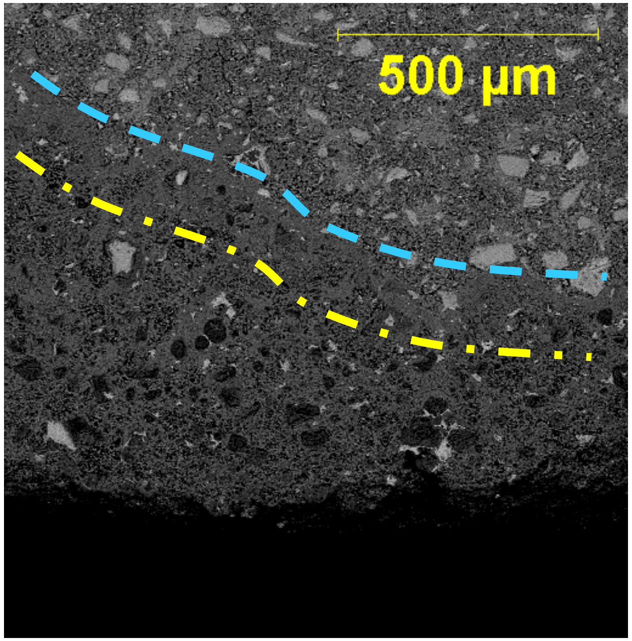
- **Bottom (Aqueous phase saturated with CO_2)**
  - Visible orange on surface
  - Smooth texture
  - Soft, weak

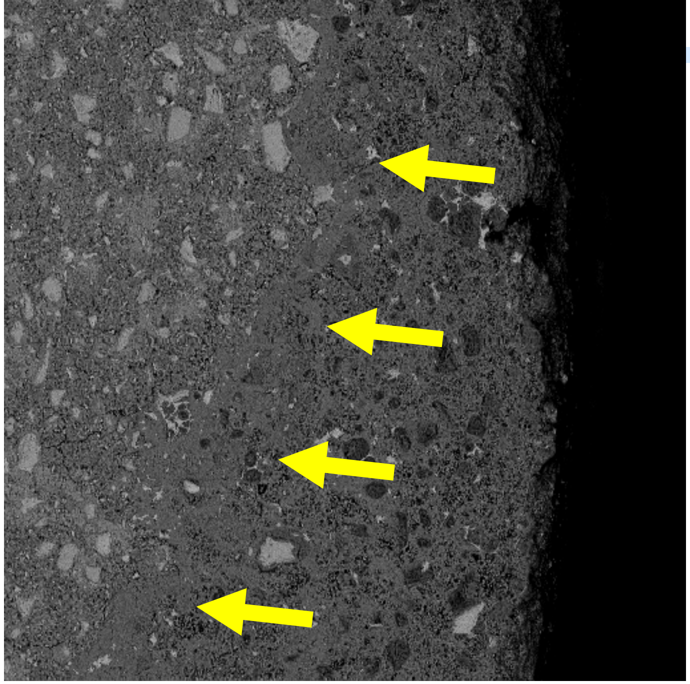


Unhydrated cement grains
Unaltered Cement Paste
Calcium-rich zone
Calcium depleted cement grains
Calcium depleted region
500 µm
Highly porous rim

- Mechanical Difference







•Chemistry of carbonated attack

1. **Carbonation**

   Acid attack on calcium hydroxide:

   $Ca(OH)_{2\ (s)} + H_2CO_{3\ (aq)} \rightarrow CaCO_{3\ (s)} + 2\ H_2O$

   Degradation of Calcium-Silicate-Hydrate:

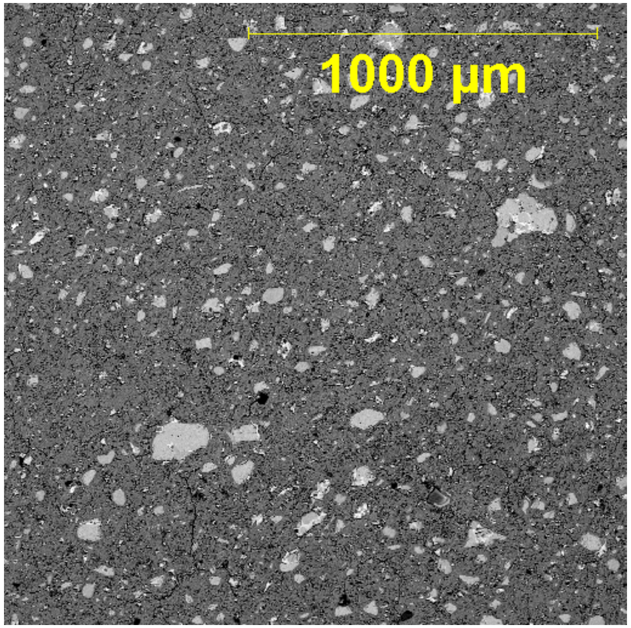
   C-S-H + $H_2CO_{3\ (aq)} \rightarrow CaCO_3$ + amorphous silica gel

2. **Bicarbonation**

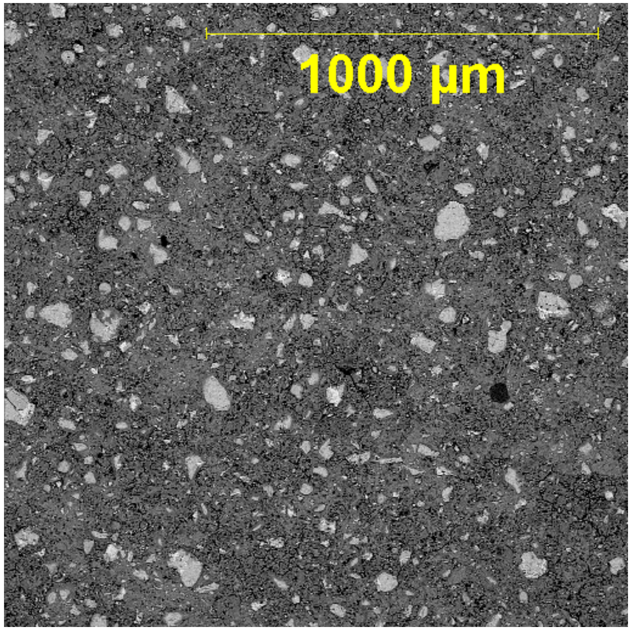
   $CaCO_{3\ (s)} + H_2CO_{3\ (aq)} \rightarrow Ca(HCO_3)_{2\ (aq)}$

Results of Various Cure Conditions – Before Exposure

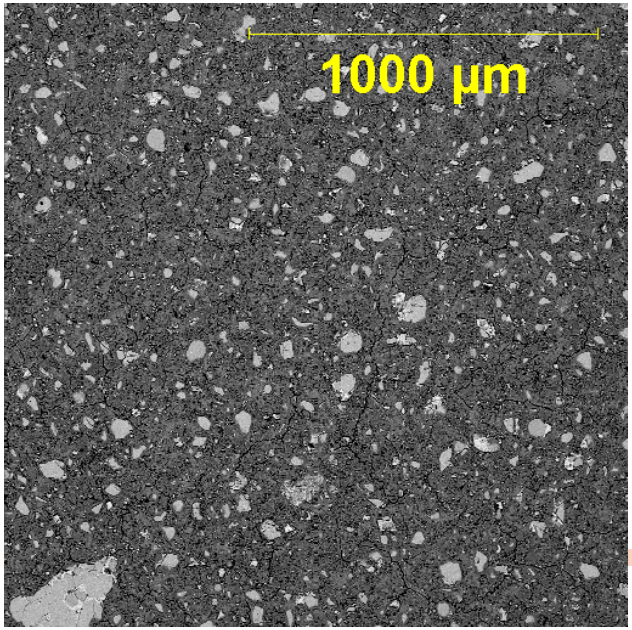
HTHP



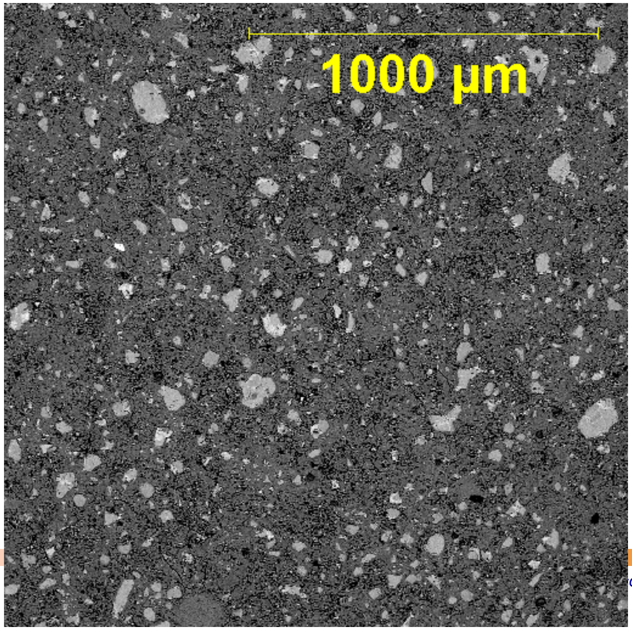
LTHP



HTLP



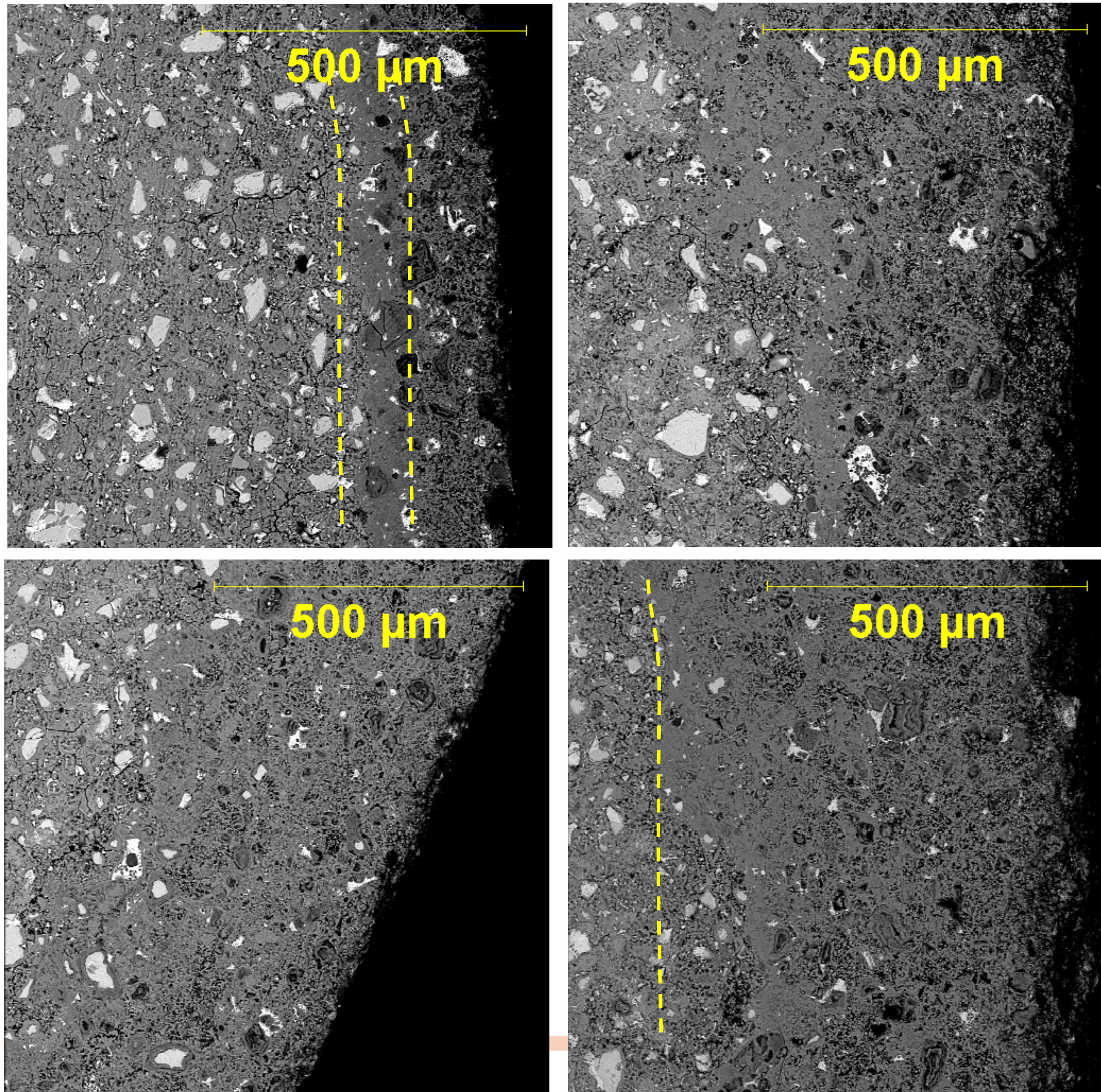
LTLP



Effect of Cure Conditions on HTHP Degradation

HTHP

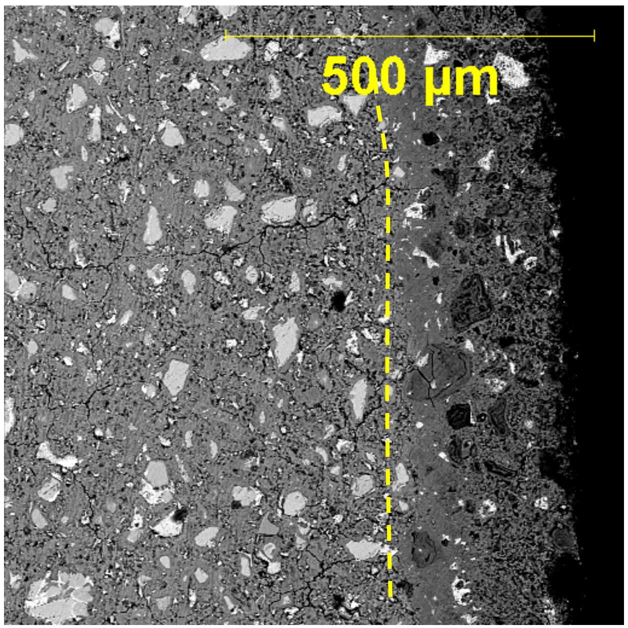
LTHP



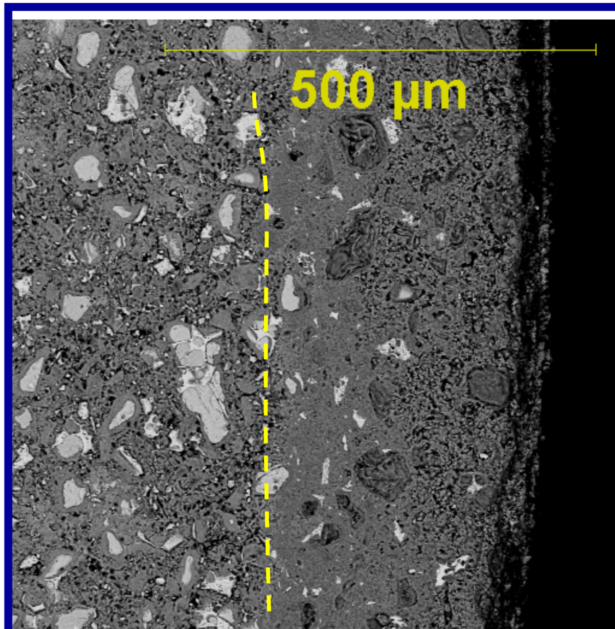
HTLP

LTLP

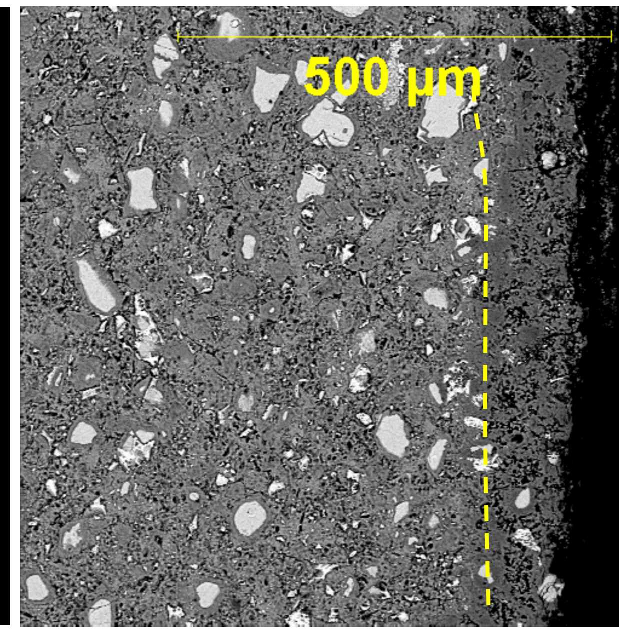
Depth of Degradation
Headspace vs. Aqueous Phase



Aqueous Phase: 9 days
HTHP CO_2 exposure

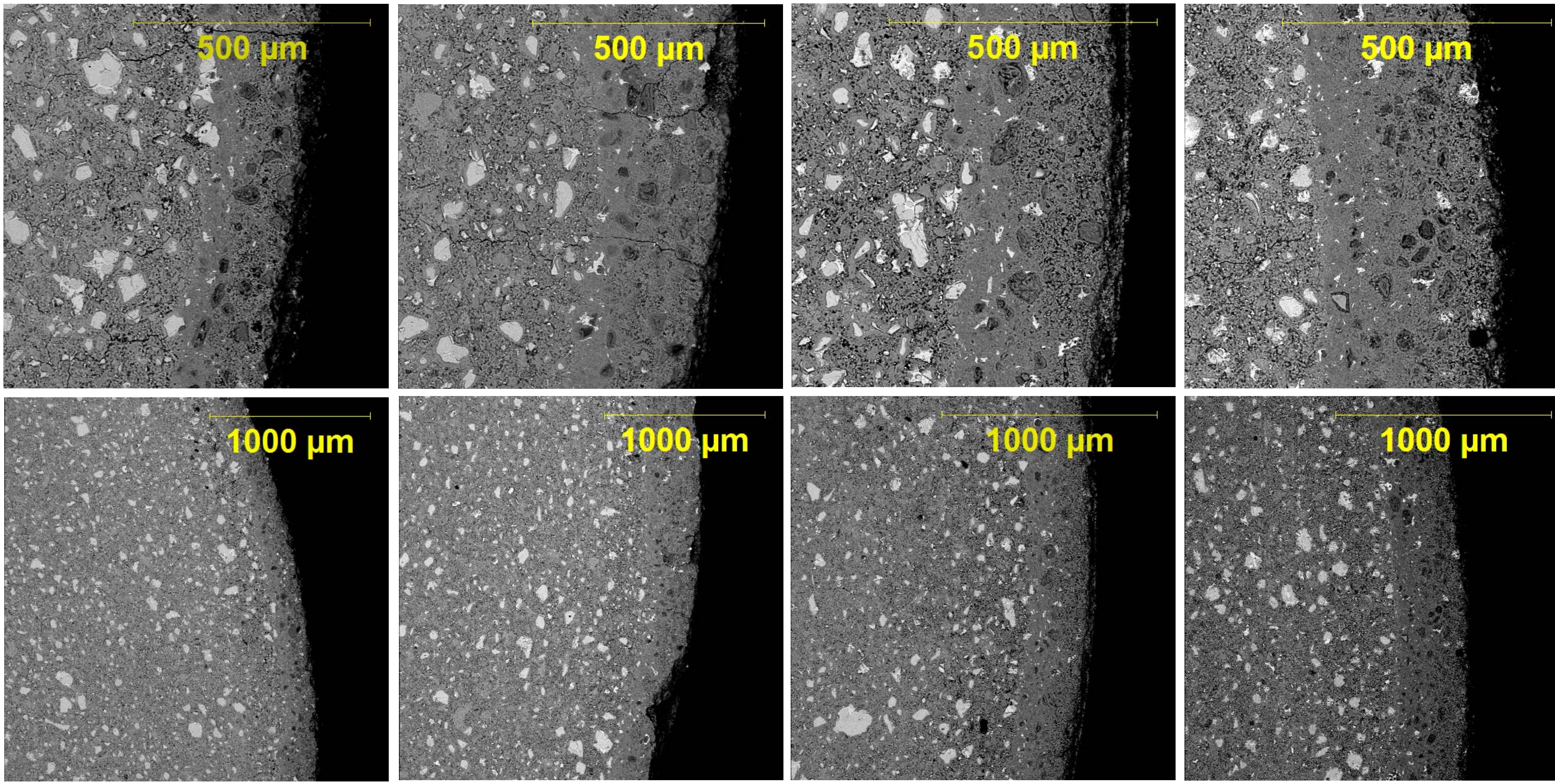


Aqueous Phase: 61 days
HTHP CO_2 exposure



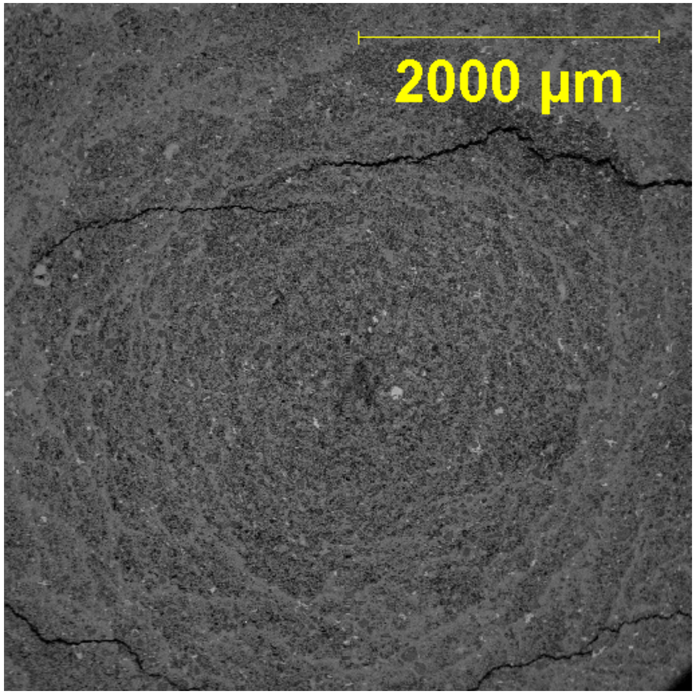
Headspace: 61 days
HTHP CO_2 exposure

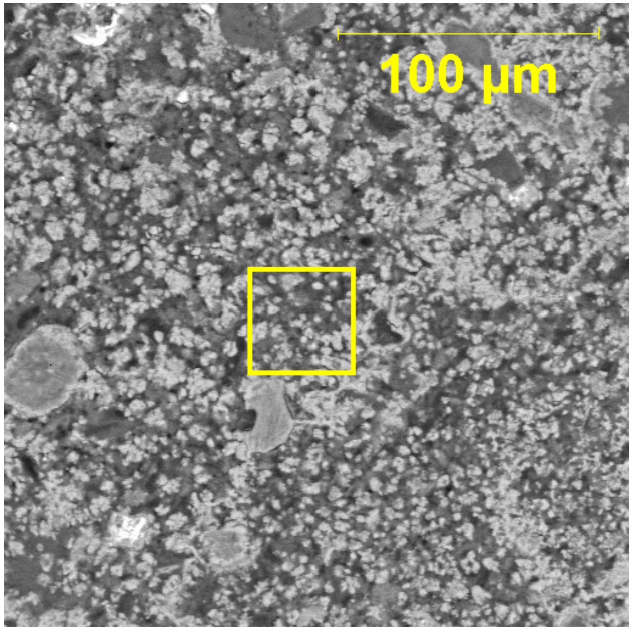
Progression of Degradation at HTHP – Aqueous Phase

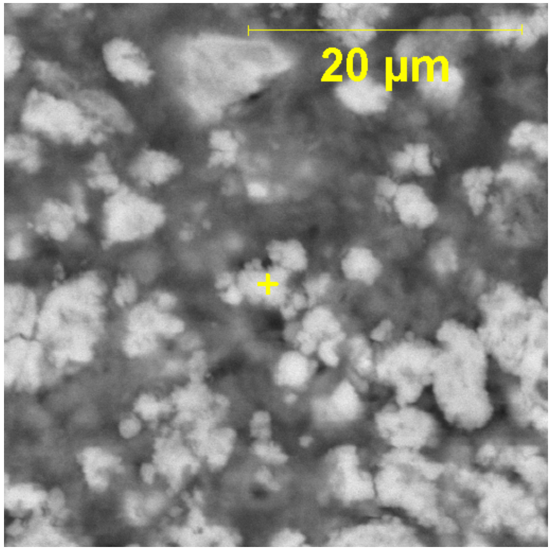


9 days	23 days	61 days	90 days
~200 µm	~330 µm	~430 µm	~440 µm

Degradation of Class H with 6% Bentonite







- **Bicarbonation leaves behind "Popcorn" crystals of calcite in isotropic matrix of silica gel**
  - Act as sand grains rather than binding agent.
  - New binding agent is now the decalcified silica gel

Conclusions (so far…)

- **Importance of simulated geologic sequestration conditions**
  - HTHP cure
    - Increased hydration
    - Smaller, more evenly distributed CH crystals
    - Lower rate of attack
  - Exposure to CO_2 gas phase
  - Exposure to CO_2 saturated aqueous phase
- **Degradation of cement**
  - Mineralogical changes
  - Mechanical changes
  - Progresses with time

Future Work

- **Continue with longer exposure times**
- **Exposure of cement with additives**
  - Bentonite
  - Fly ash
- **Different exposure conditions**
  - Temperature
  - Pressure
  - Salinity

Acknowledgements

- **George Scherer**
  - Princeton University
- **Andrew Duguid**
  - Princeton University
- **Craig Gardner**
  - Chevron Texaco, Sr. Advisor - Cementing
- **Glen Benge**
  - Exxon Mobile, Drilling – Technical Applications
- **Niels Thaulow**
  - RJ Lee Group, Sr. Cement Advisor

CO_2 Resistant System

V.Barlet-Gouédard, G.Rimmelé, O.Porcherie, Schlumberger, B.Goffé, CNRS/ENS*

2nd Well Bore Integrity Network Meeting
28–29 March 2006, Princeton University

CO_2 Resistant system

- Motivation and Approach
- Methodology
- Comparison between Portland cement and the new carbon dioxide resistant system
- Conclusions and Future

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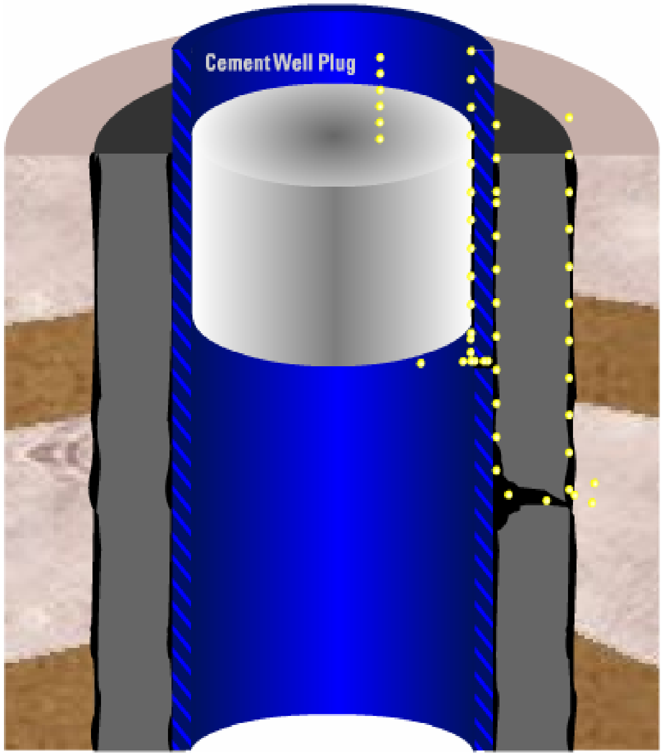
Motivation and Approach

- CO_2 underground storage
  - ➢ The most effective way
- Long-term zonal isolation
  - ➢ Portland cement not thermodynamically stable in CO_2 environments.
  - ➢ Not adequately addressed by industry specifications
- Develop standard procedure/method
  - ➢ A laboratory qualification of resistant cements
  - ➢ The long-term modeling of cement-sheath integrity



Measurements of chemical attack

- pH of fluid in equilibrium with samples
- Physical parameters:
  - weight
  - density
  - compressive strength
  - porosity

Portland Cement

Alteration of Portland cement:

- efficient process in both CO_2 fluids

- complex series of fronts in both CO_2 fluids → favours its degradation

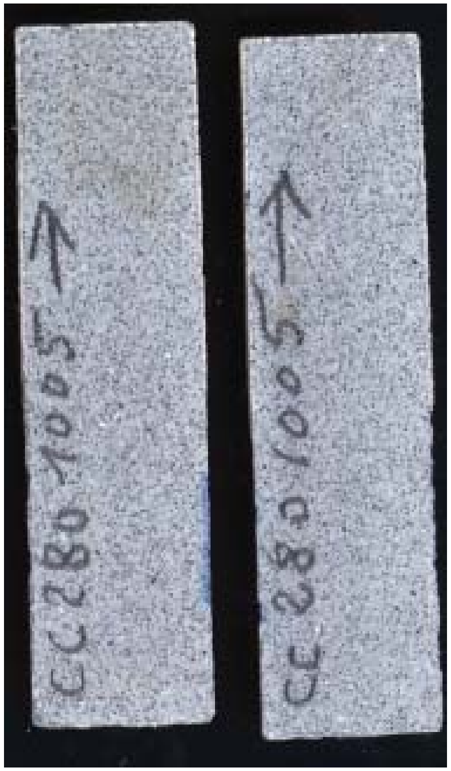
CO_2 Resistant System

- Chemistry effect : selection of a durable material to reduce Portland amount
- Special system with low water
- Slurry to have a large density range (12.5 ppg and 17 ppg)

Kinetic tests with CO_2 resistant System

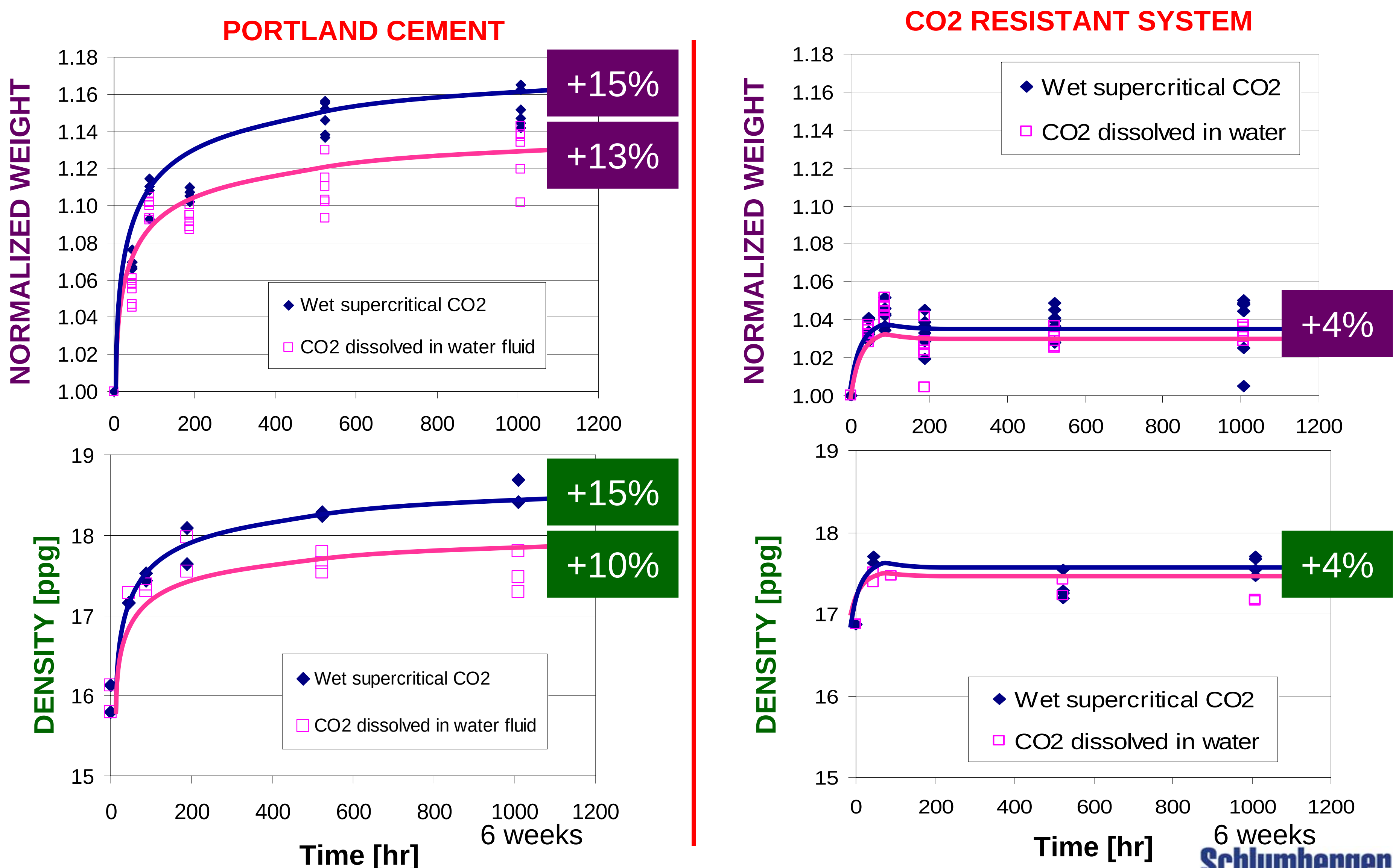
2 days

1 week



6 weeks

Evolution of weight and density with time



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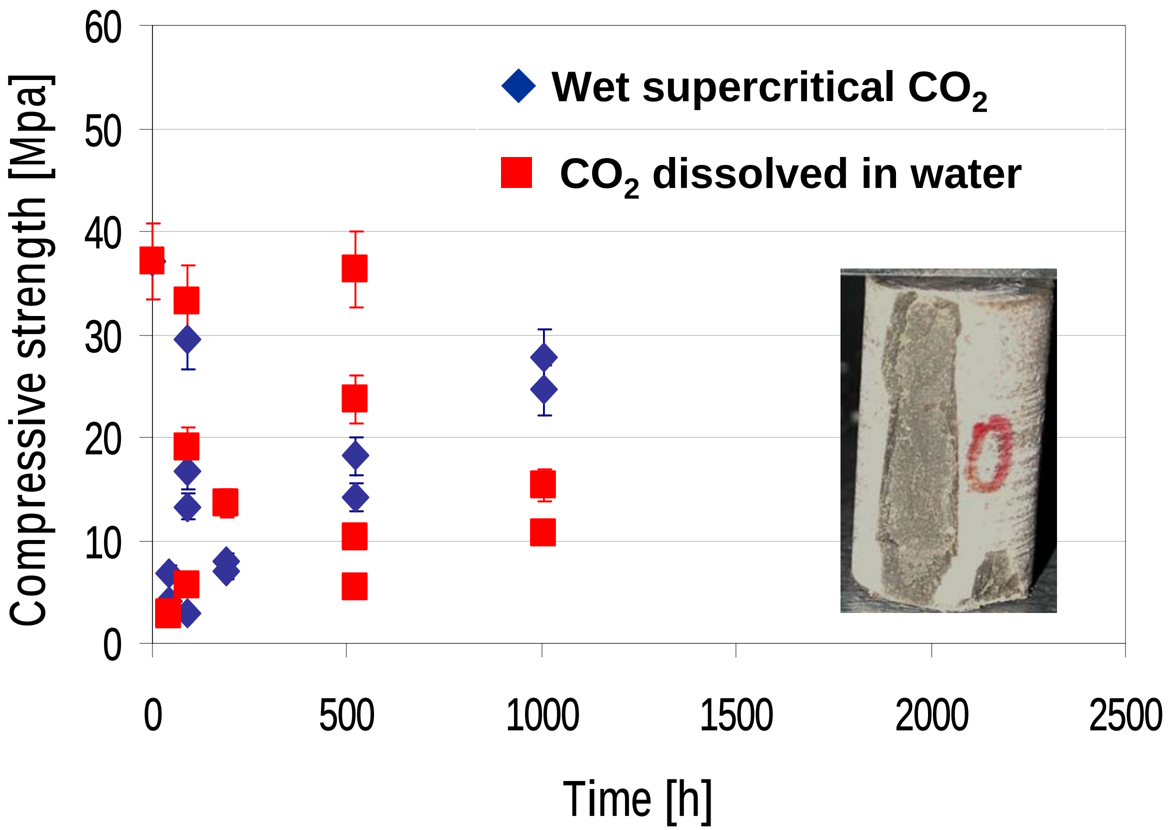
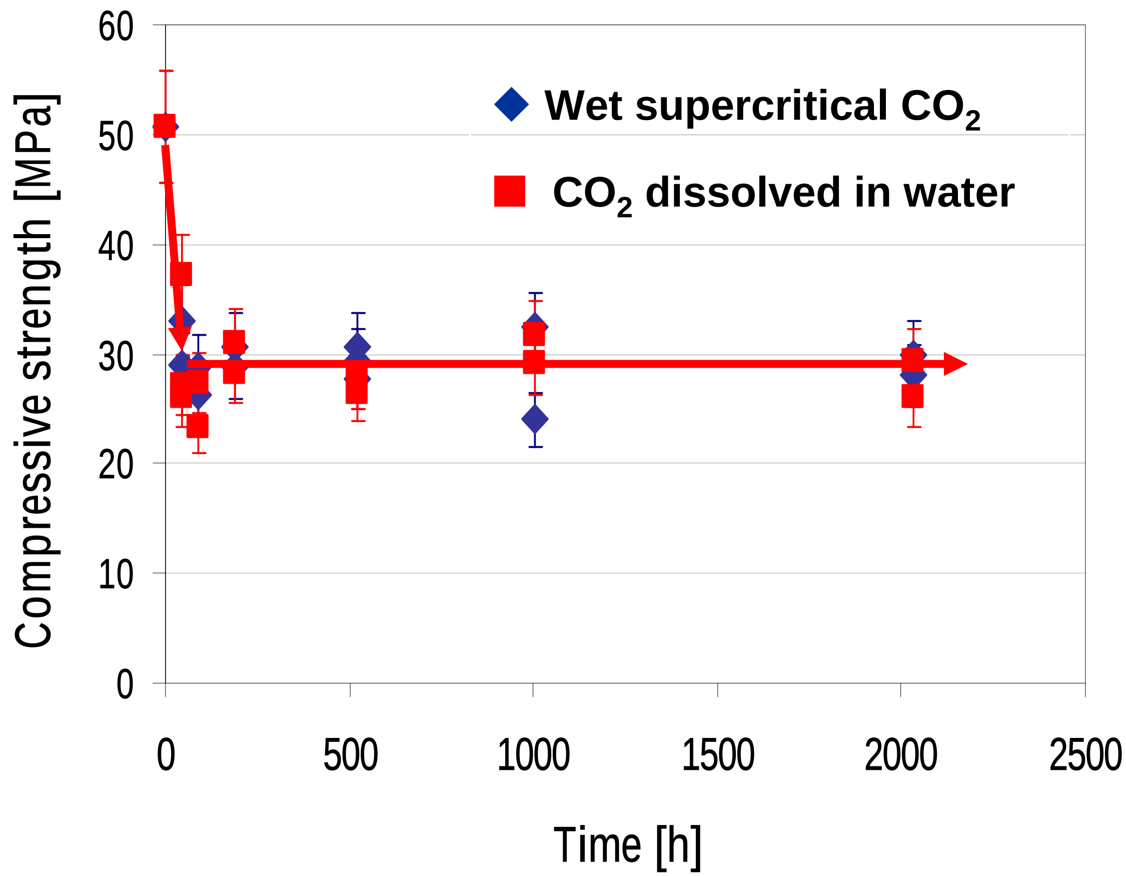
Compressive strength evolution

Portland Cement



Compressive strength evolution

CO_2 Resistant System



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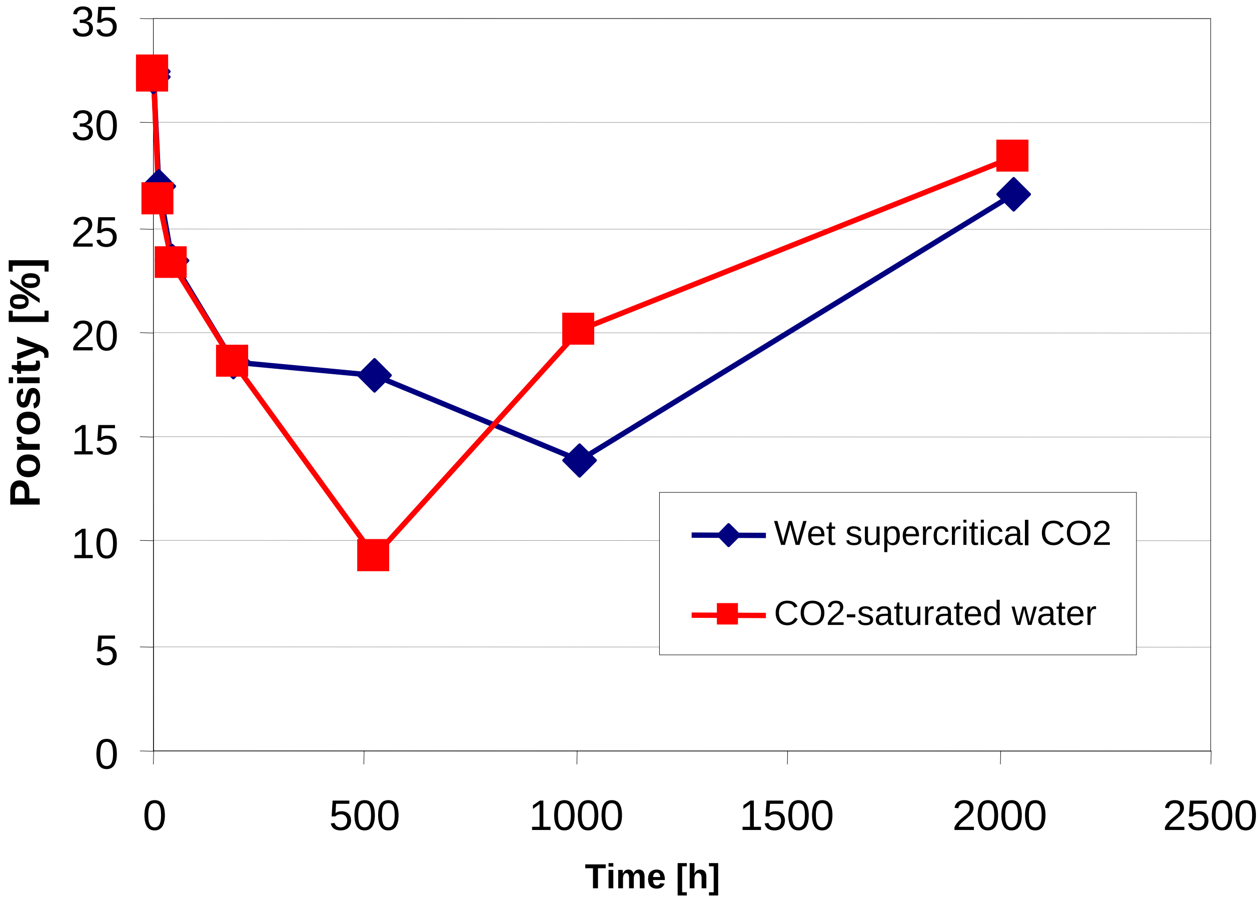
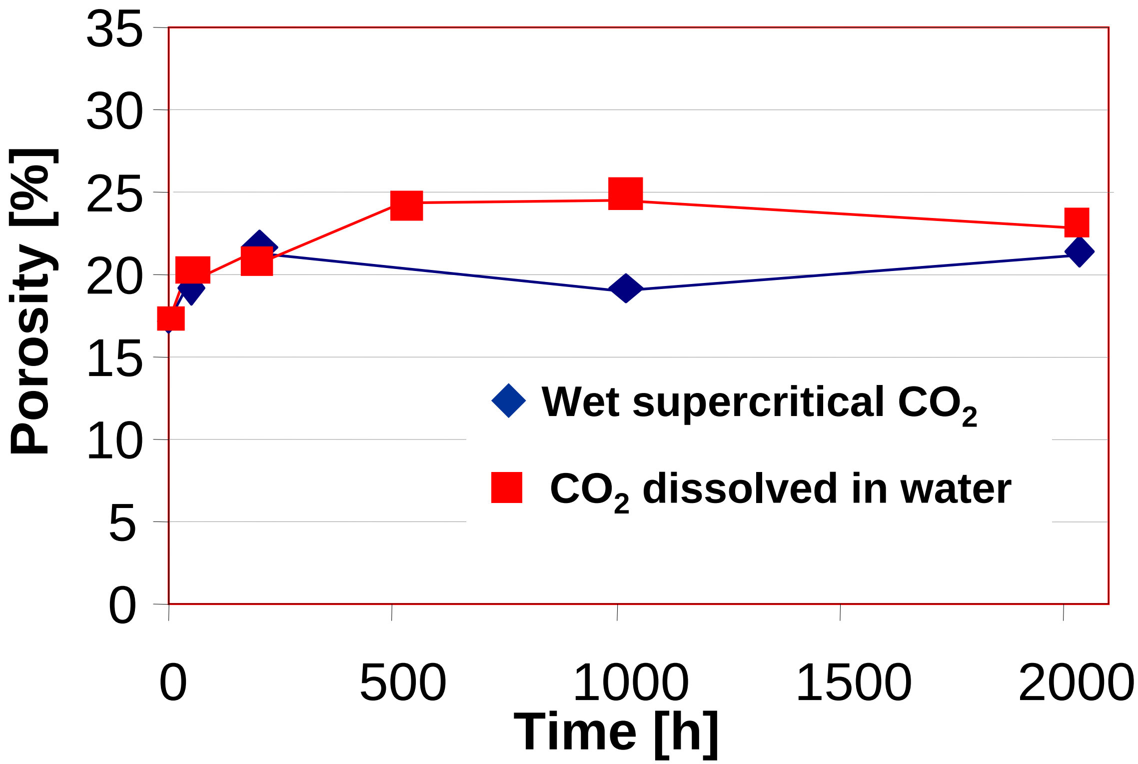
Evolution of Porosity

Portland Cement

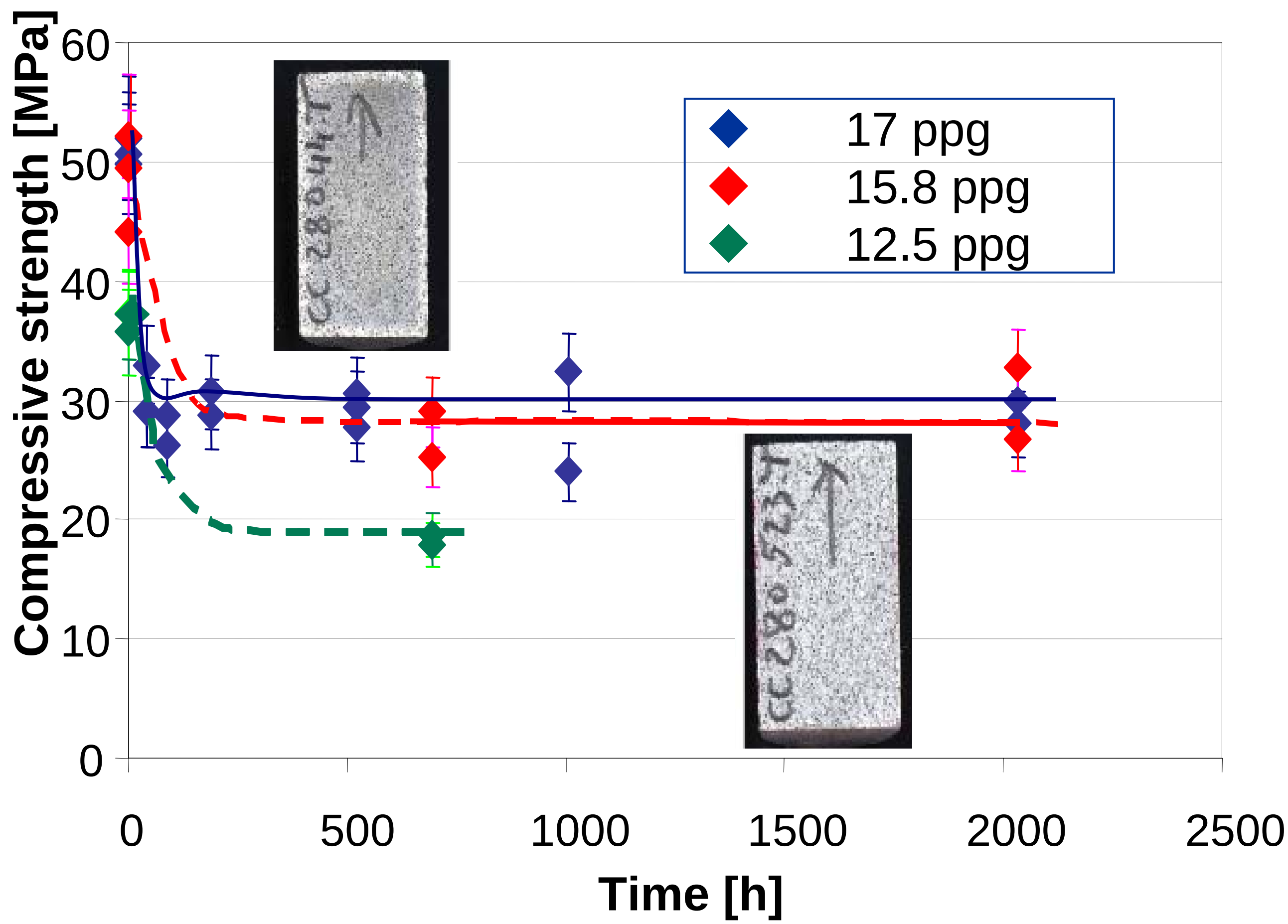


Evolution of Porosity

CO_2 Resistant System



CO_2 Resistant System validation



Conclusions and Future

- A new methodology to simulate downhole conditions
  – Procedure validation
  – Reproducible and repeatable
- Portland cement
  – A very effective process following a diffusion law
  – An initial sealing by carbonation then a dissolution stage
- CO_2 Resistant System
  – Homogeneous pattern with a limited carbonation threshold: good mechanical behaviour over a wide density range
  – Stable in both CO_2 fluids up to 3 months
  – IADC/SPE 98924: Mitigation strategies for the risk of CO_2 migration through wellbores
- Accelerated ageing method

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Thanks for your attention!

Questions?

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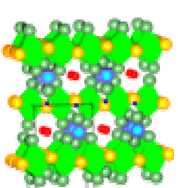
Reactive Transport Modeling of Cement-Brine-CO_2 Systems

Bill Carey, Peter Lichtner, Rajesh Pawar, and George Guthrie, Jr.

Earth and Environmental Sciences
Los Alamos National Laboratory

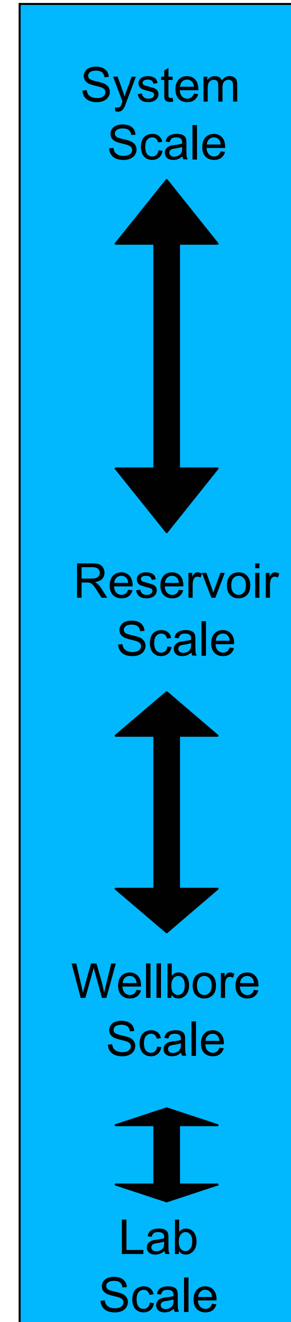
2nd Wellbore Integrity Network Meeting
March 2006
Princeton University



Los Alamos NATIONAL LABORATORY

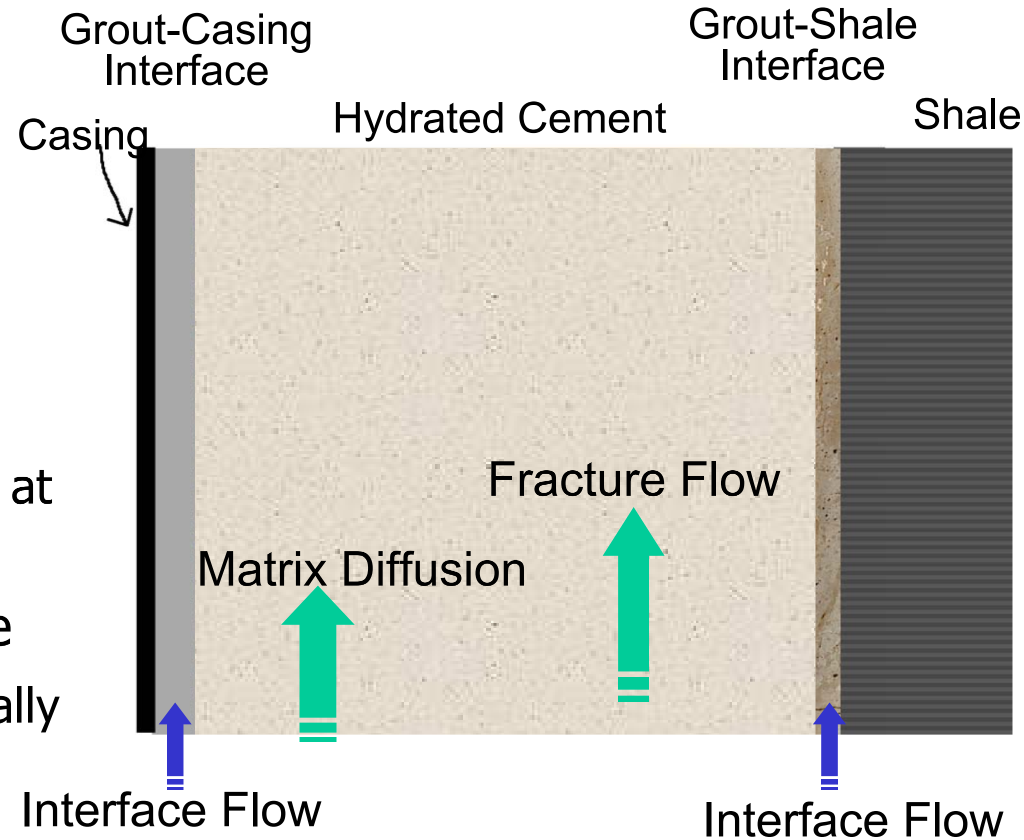
Outline

- Cement Behavior
  - Field observation
  - Laboratory investigations
- Numerical Simulation
  - Reactive transport code
- Comparison to SACROC
- Comparison to Duguid/Scherer experiments
- Missing elements



Cement Degradation: Carbonation

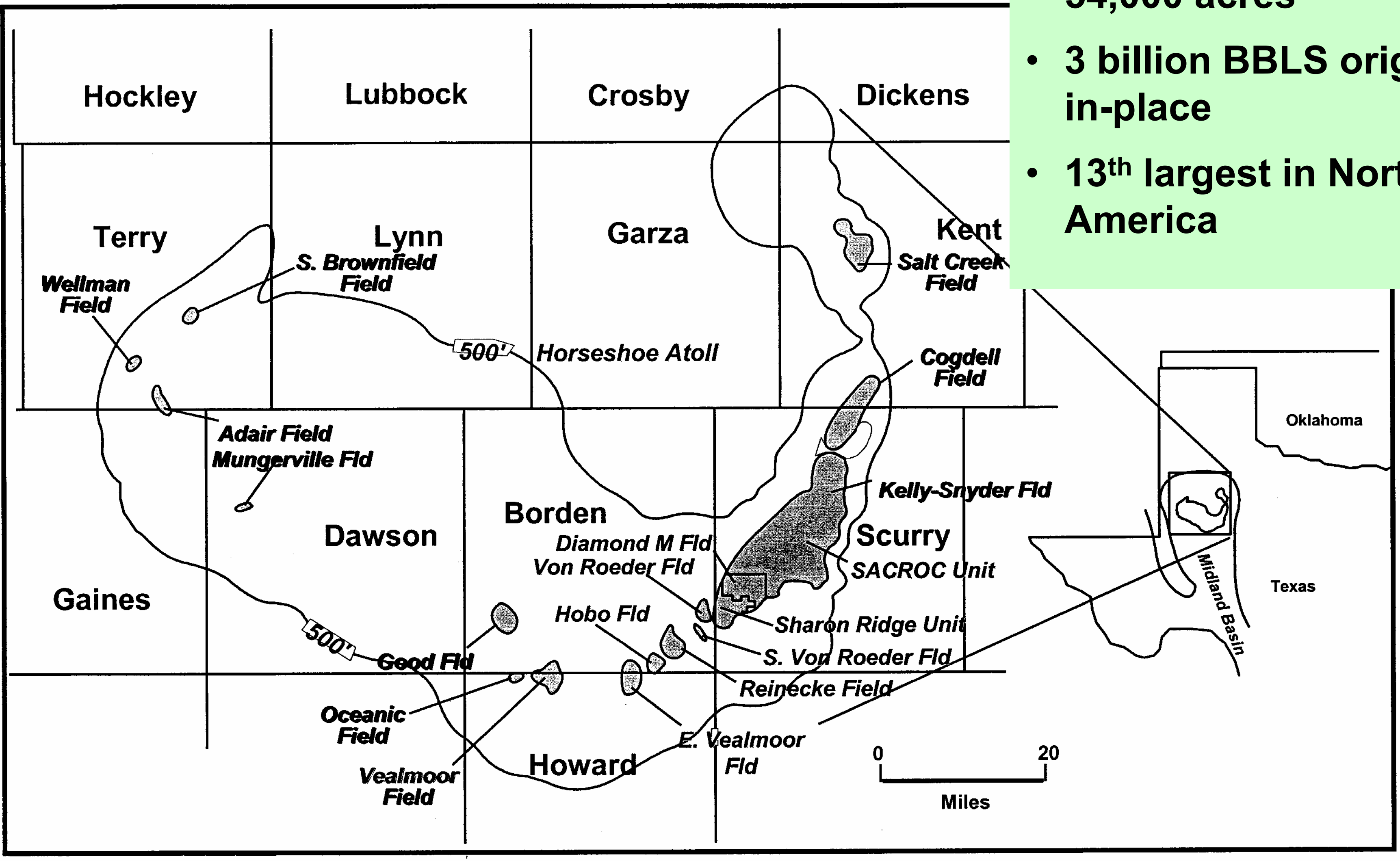
- Decrease in porosity
- Decrease in permeability
- Increase in strength
- Reduction of pH of pore fluid
  - May allow corrosion to occur at casing interface
- Carbonation-induced shrinkage
  - Formation of cracks (potentially filled with carbonate)



- Reduction of casing/cement and/or cement/caprock interface integrity
- Loss of structural integrity at ultimate carbonation state
  - $CaCO_3$ + amorphous silica, alumina, and ferric hydroxides
- Important factors controlling rates of carbonation
  - Saturation and relative humidity
  - Water/Cement ratio
  - Age of cement

Field Studies: SACROC

- **Pennsylvanian age reef system**
- **Discovered 1948**
- **54,000 acres**
- **3 billion BBLS original oil in-place**
- **13th largest in North America**



Reaction Textures at SACROC

Numerical Analysis of Cement Degradation: FLOTRAN

- Two-phase multicomponent reactive flow and transport
  - Mass & energy conservation
  - Single and dual continuum formulations
  - Darcy's law for two-phase liquid-air system
  - Aqueous speciation (Debye-Hückel and Pitzer)
  - Kinetic formulation of solid reactions
  - Mineral solid solutions implemented as stoichiometric species

- 1-D diffusion of CO_2-saturated brine into cement
- Idealized cement: 38% C-S-H (x_{SiO2}=0.36, Ca/Si = 1.78), 15% portlandite, 14% monosulfate, 3% hydrogarnet (30% porosity)
- Ideal shale: 20% illite, 7% quartz, 1% kaolinite 1% calcite, 1% dolomite (70% porosity)
- C-S-H solid solution based on experimental solubility data

C-S-H Solid Solution Model

Endmembers: $Ca(OH)_2$ and SiO_2

Mol-fraction $X_{SiO2} = 1 / (1+R)$, $R = Ca/Si$

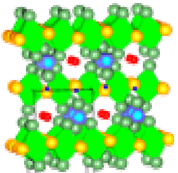
Lippman Variable: $\log\left(a_{Ca^{2+}} a_{OH^-}^{2} + a_{SiO_2}\right)$

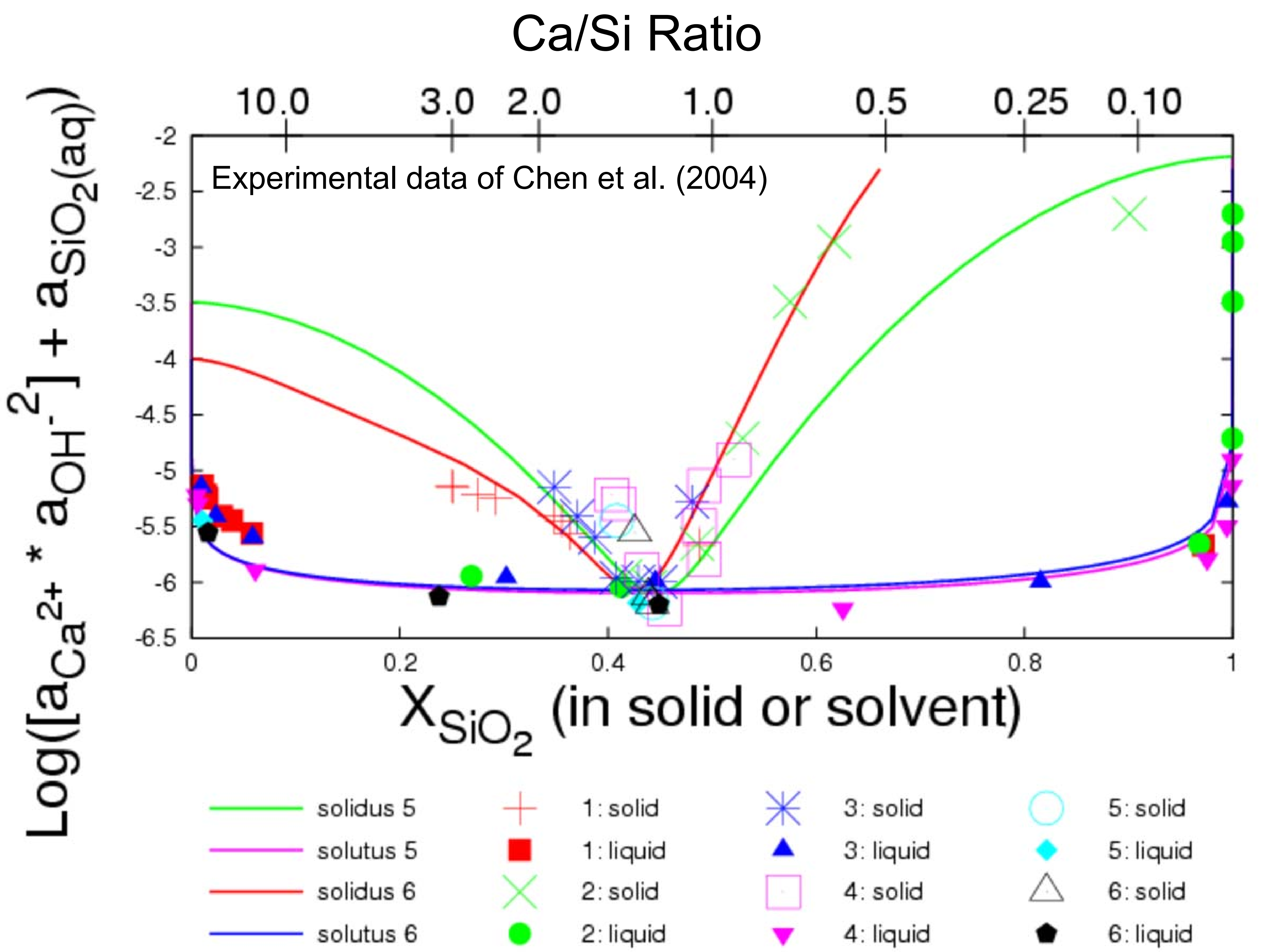
Excess Mixing Model:

$$G^E = x(1-x)RT[a_0 + a_1(x-(1-x)) + a_2(x-(1-x))^2]$$

Parameter Estimation:

$\mu_{Ca(OH)2}, \mu_{SiO2}$, a_0, a_1, a_2, (a_3)





Ca/Si Ratio
10.0
3.0
2.0
1.0
0.5
0.25
0.10
Experimental data of Chen et al. (2004)
Log([a_Ca2+ * a_OH-^2] + a_SiO2(aq))
X_SiO2 (in solid or solvent)
-2
-2.5
-3
-3.5
-4
-4.5
-5
-5.5
-6
-6.5
0
0.2
0.4
0.6
0.8
1
solidus 5
solutus 5
solidus 6
solutus 6
1: solid
1: liquid
2: solid
2: liquid
3: solid
3: liquid
4: solid
4: liquid
5: solid
5: liquid
6: solid
6: liquid

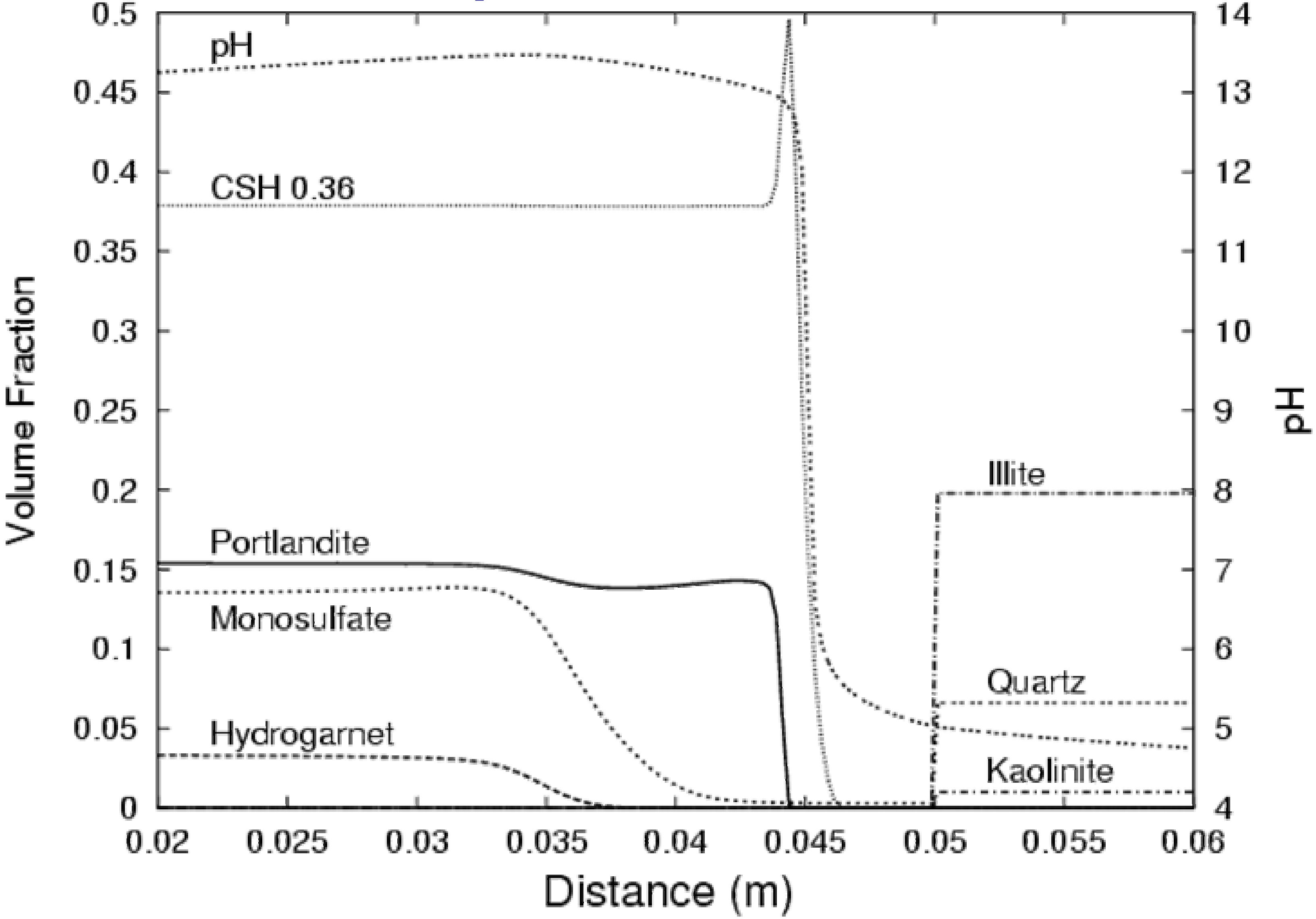
Simulation of SACROC Cement Carbonation

Phase	Gray Zone
Amorphous	Major
Portlandite	15-58%
Calcite	0-28%
Katoite	22-26%
Brucite	3-9%
Ettringite	3-4%
Friedel's Salt	2-4%
Halite	9-32%

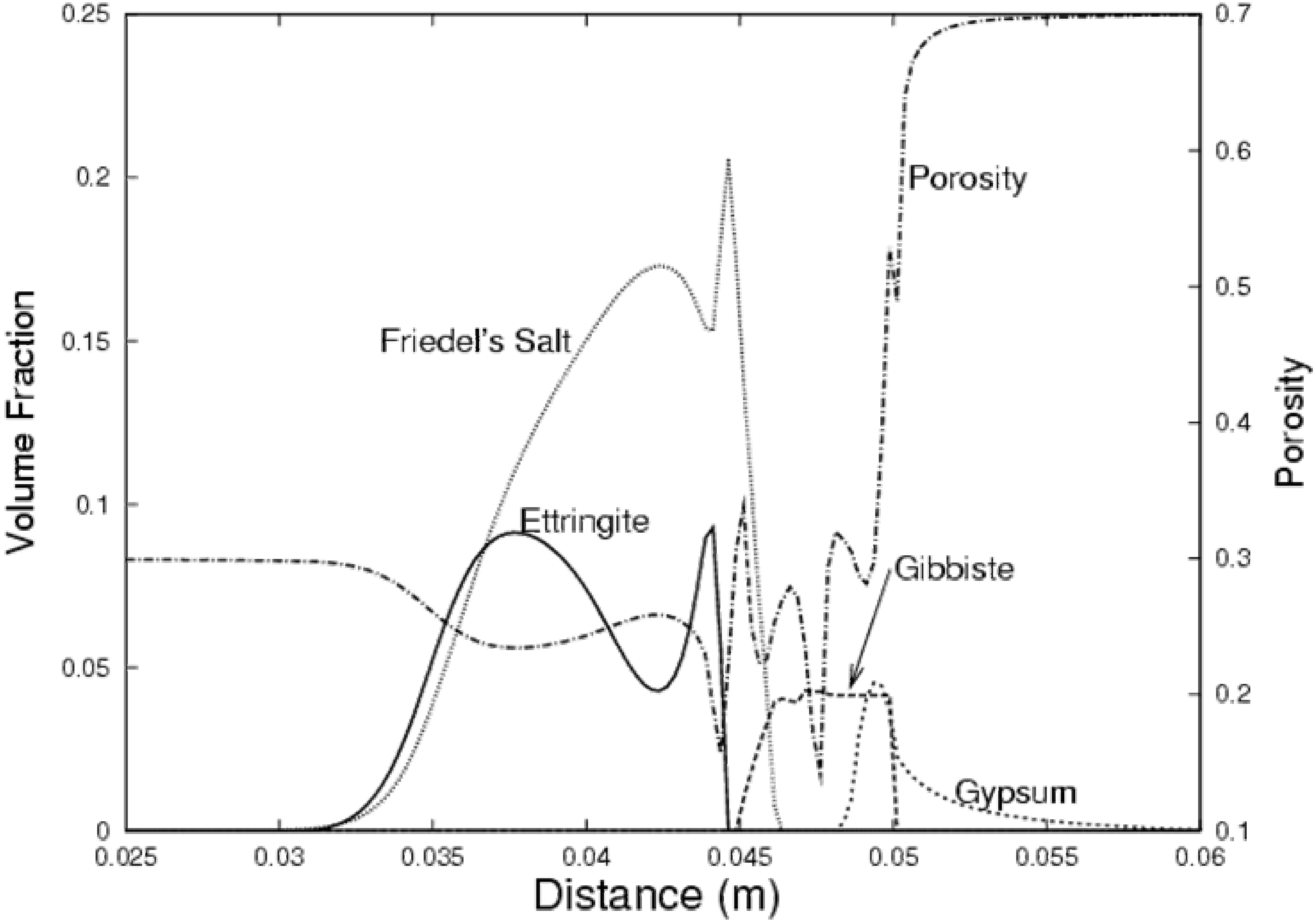
Phase	Orange Zone
Calcite	44%
Aragonite	8%
Vaterite	33%
Halite	13%

- 30 years exposure to CO_2
- CO_2-saturated brine diffuses along porous cement-shale interface zone
- Initial cement porosity 30%; initial interface 70% porosity

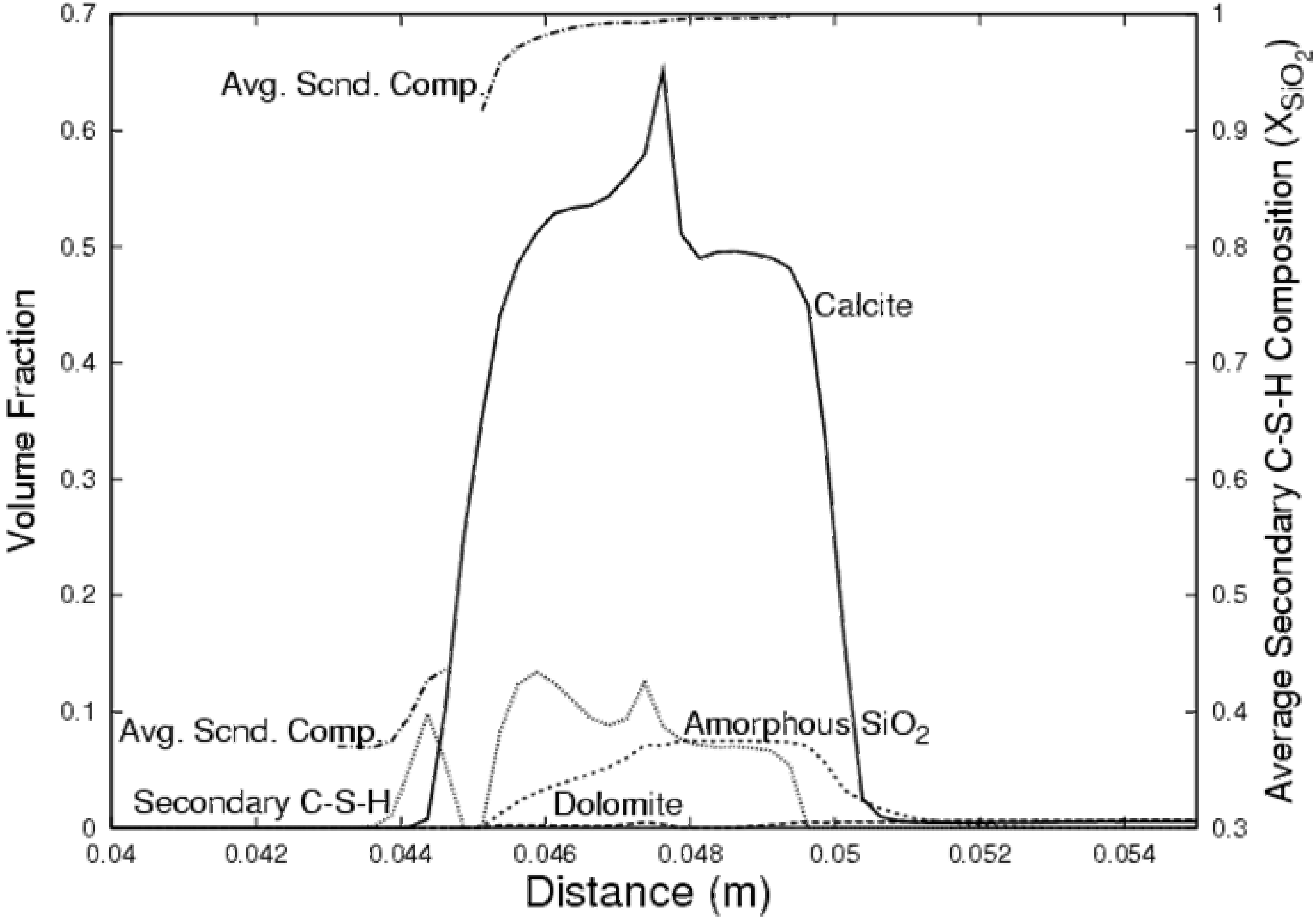
Primary Phase Behavior



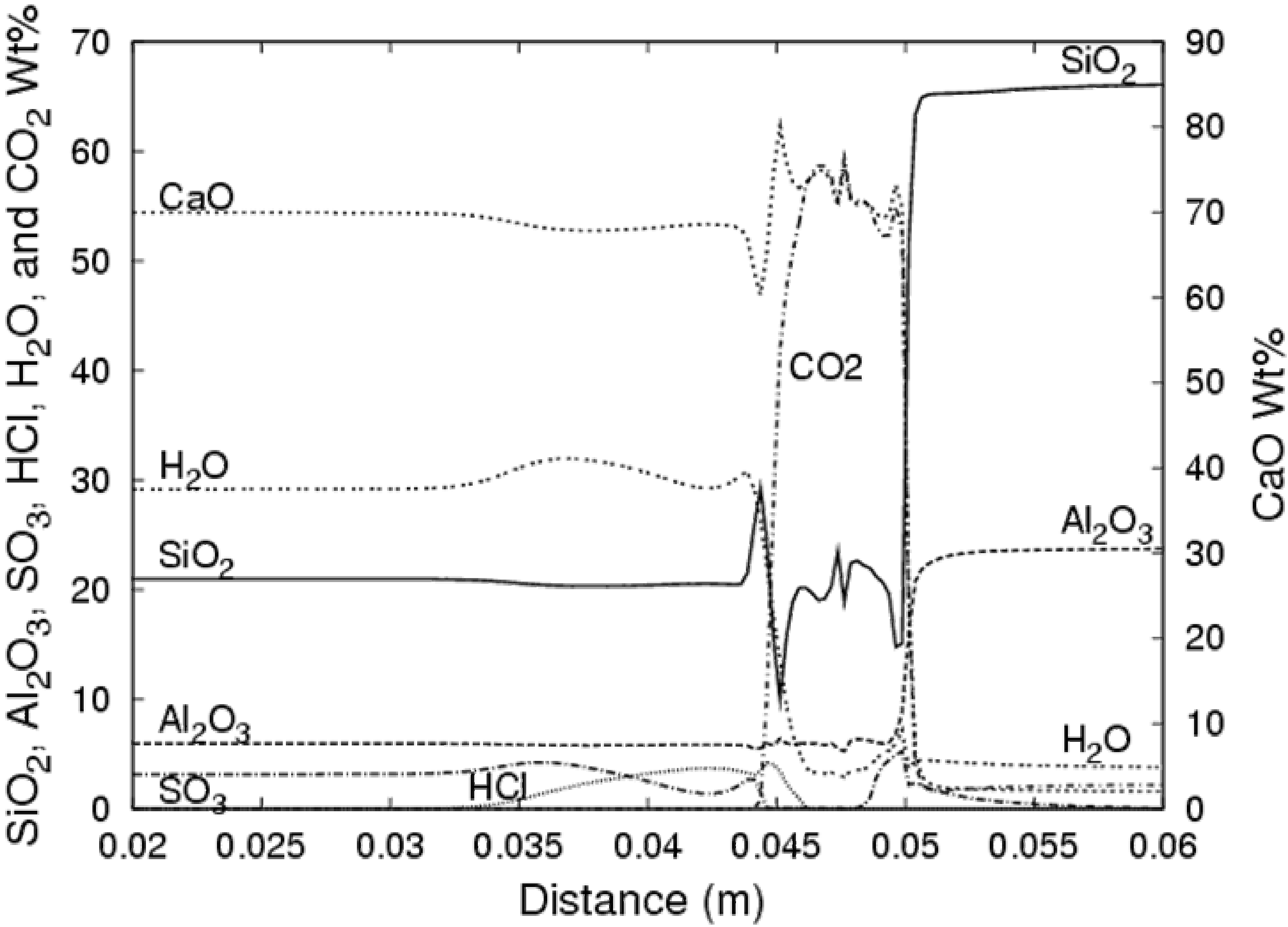
Aluminous Phases



Secondary Phases



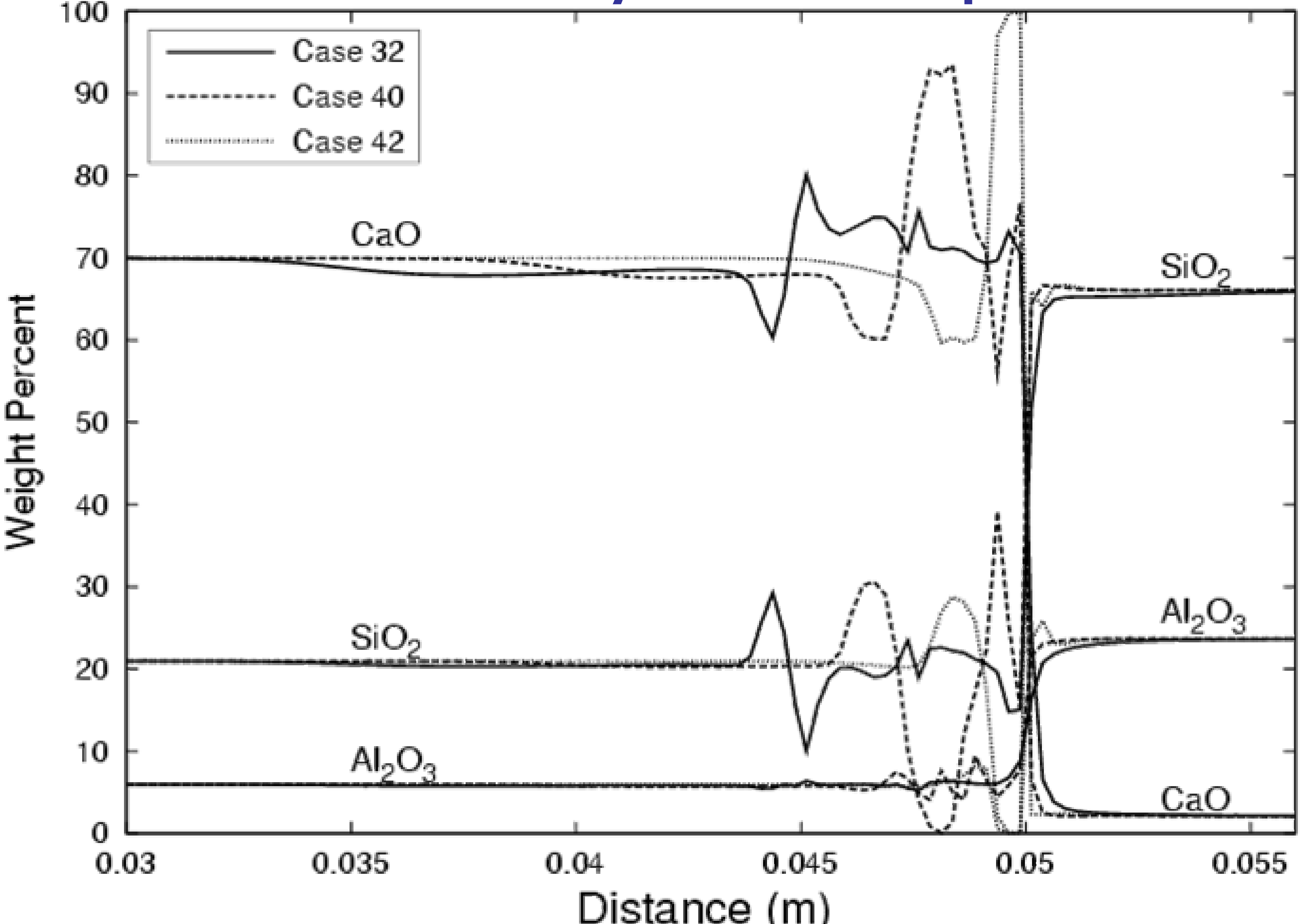
Bulk Composition



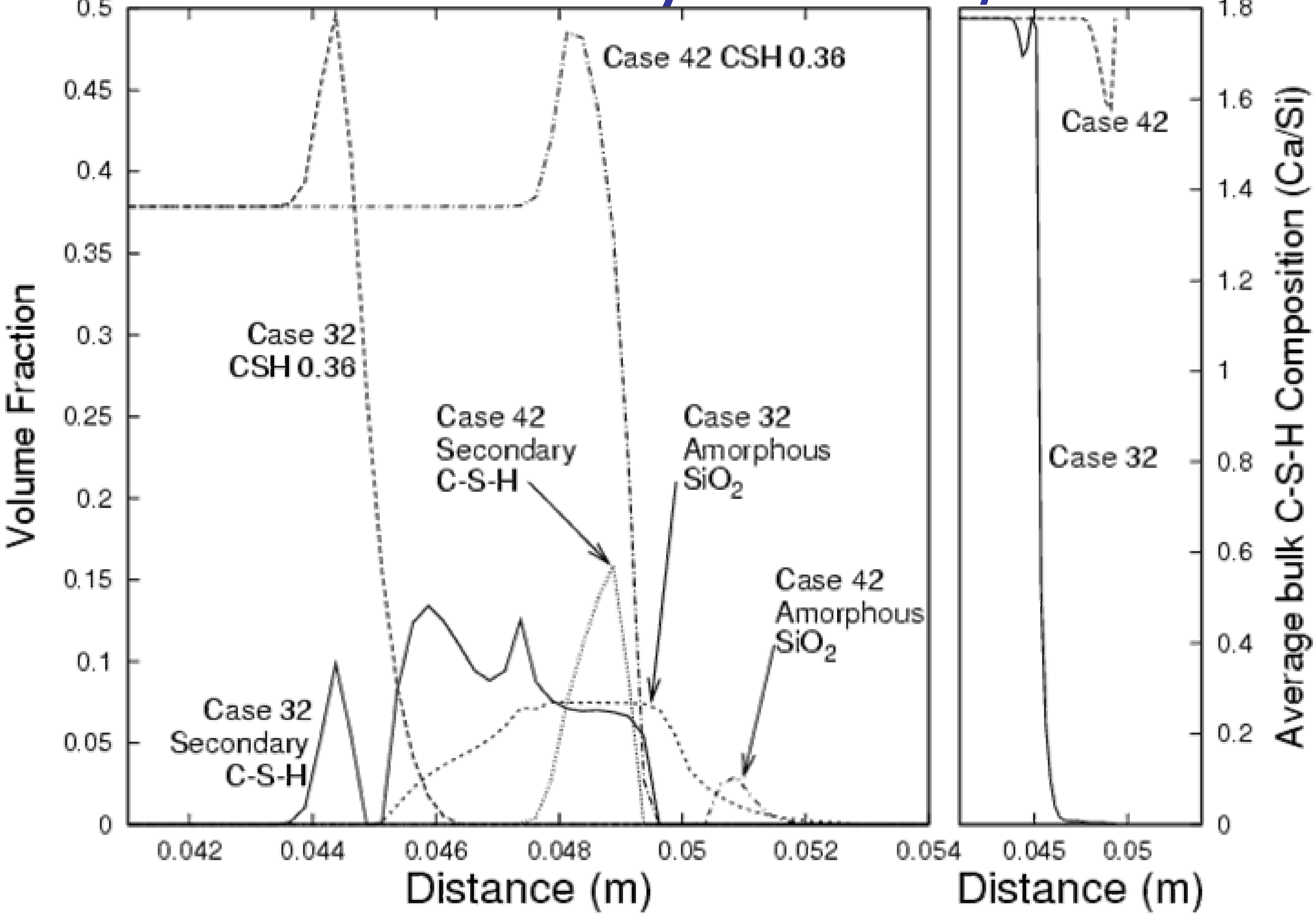
Variables

Case	Cement	Shale	Tort.	Other
32	0.3	0.7	0.0004	
40	0.3	0.3	0.0004	
42	0.3	0.09	0.0004	
34	0.3	0.7	0.004	
35	0.3	0.7	0.00004	
36	0.3	0.7	0.0004	No SS
37	0.3	0.7	0.0004	No SS or SiO_2(am)
38	0.3	0.7	0.0004	Rates/100
39	0.3	0.7	0.0004	Rates * 100
44	0.3	0.7	0.0004	Species dependent diffusion

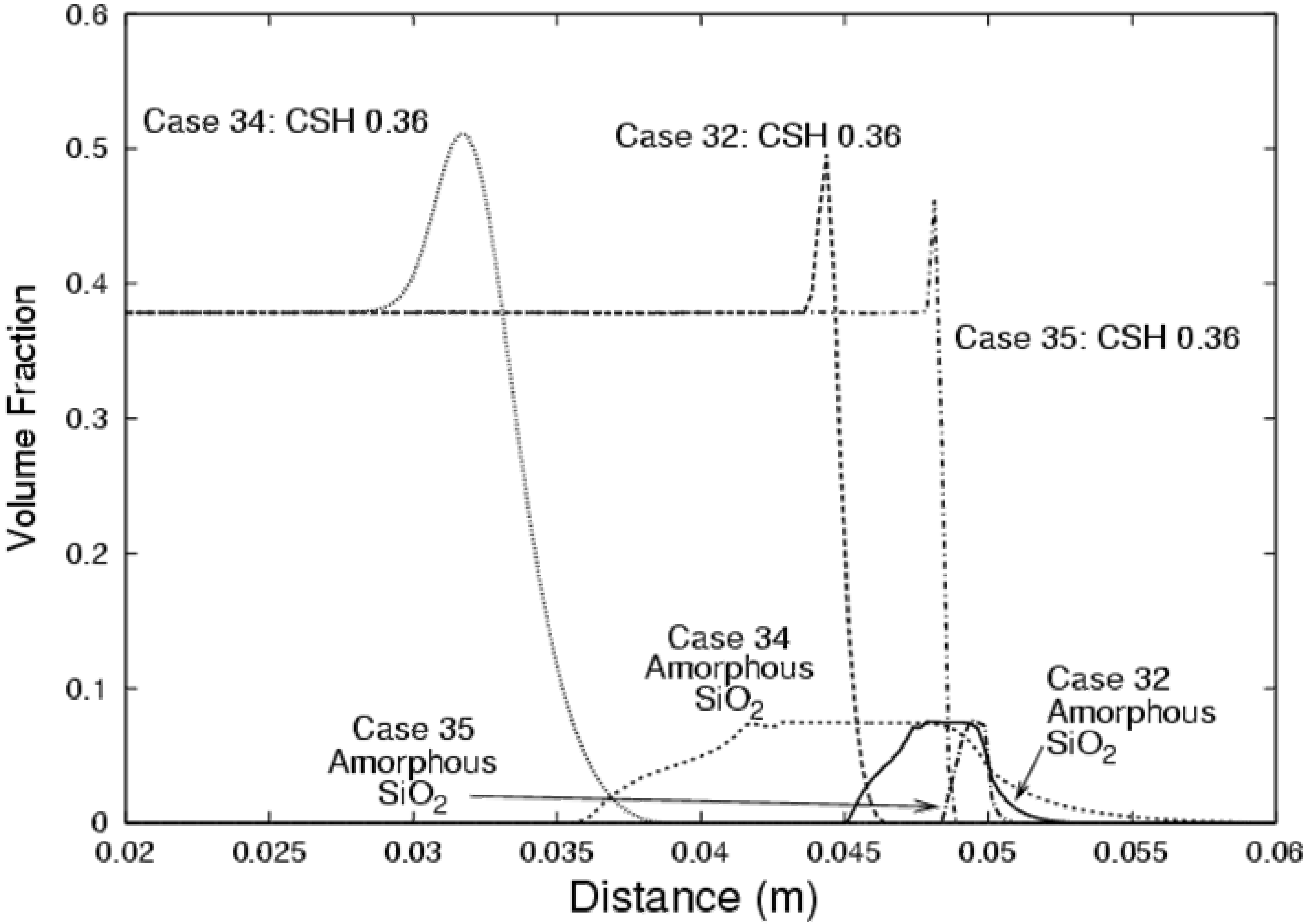
Effect of Porosity on Composition



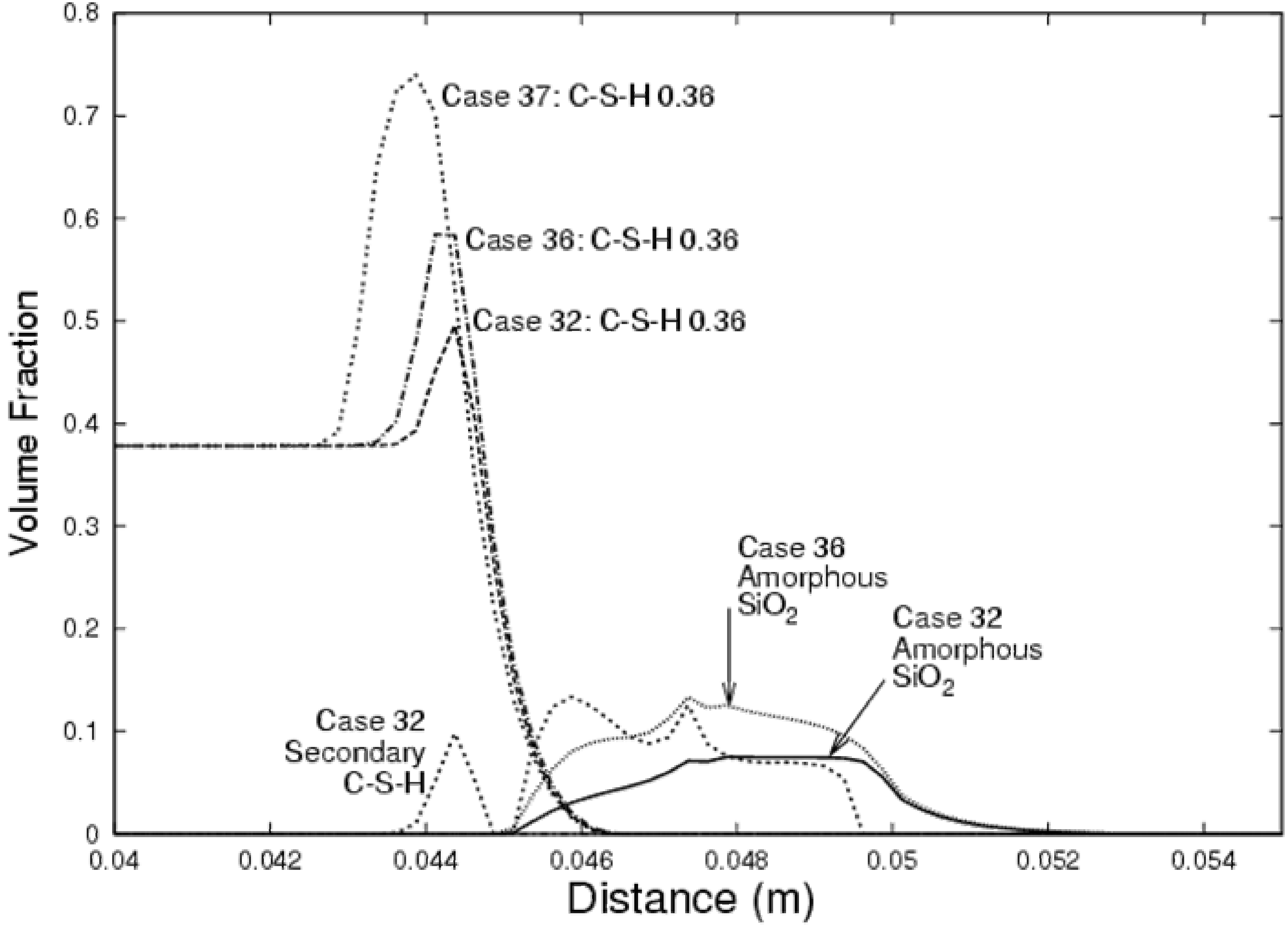
Effect of Porosity on CSH/Silica



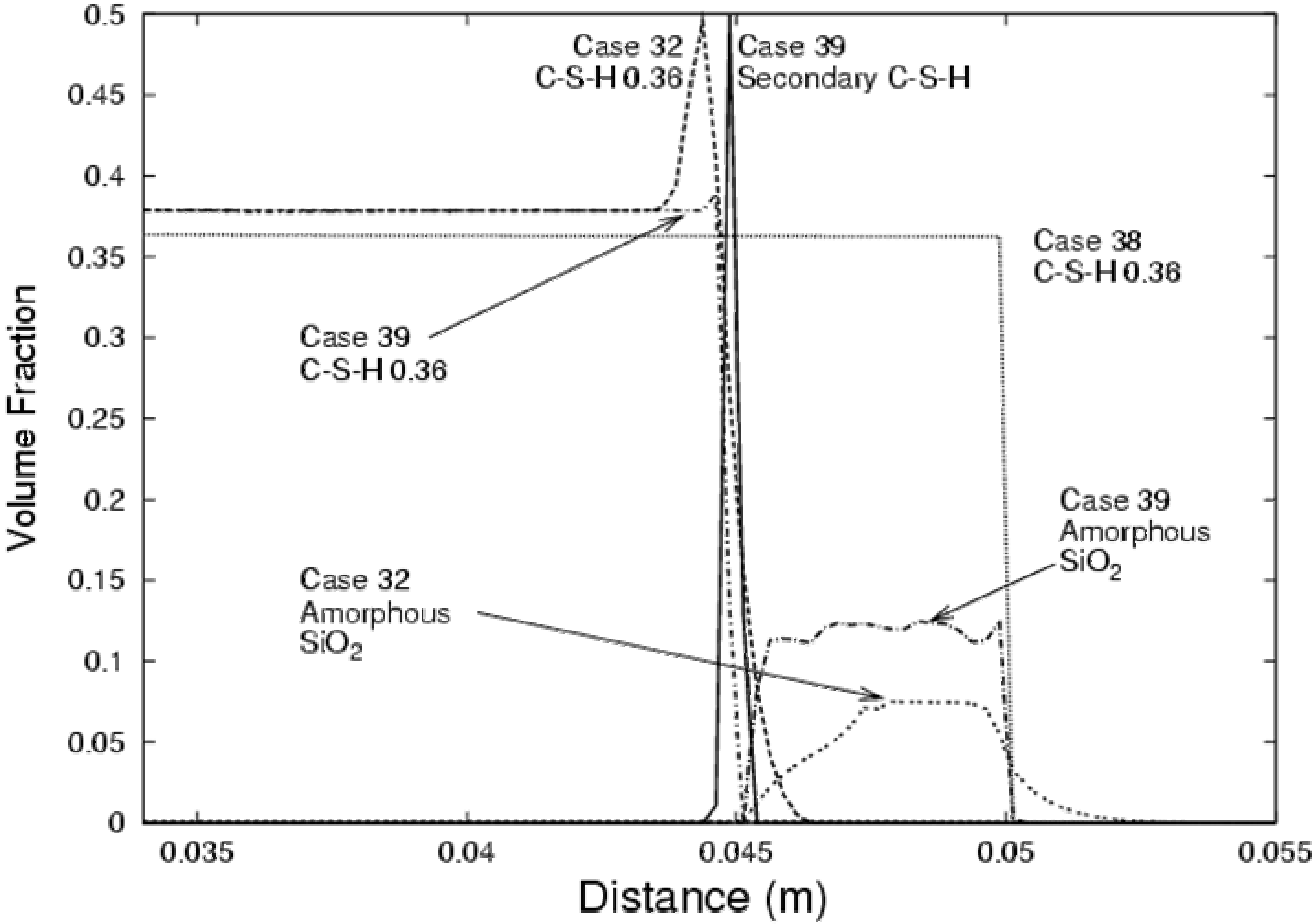
Effect of Tortuosity



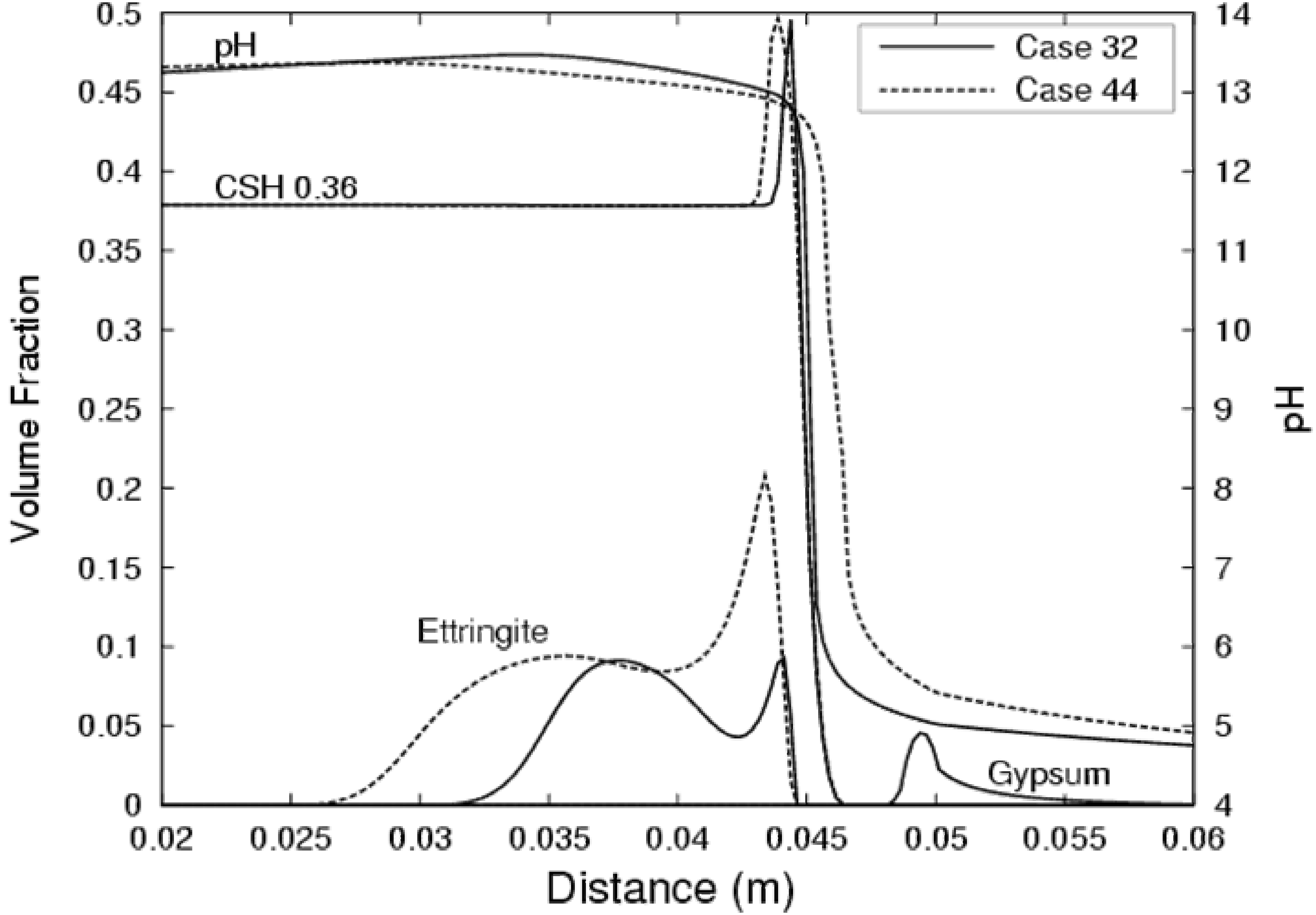
Effect of Solid Solution



Effect of Reaction Rate



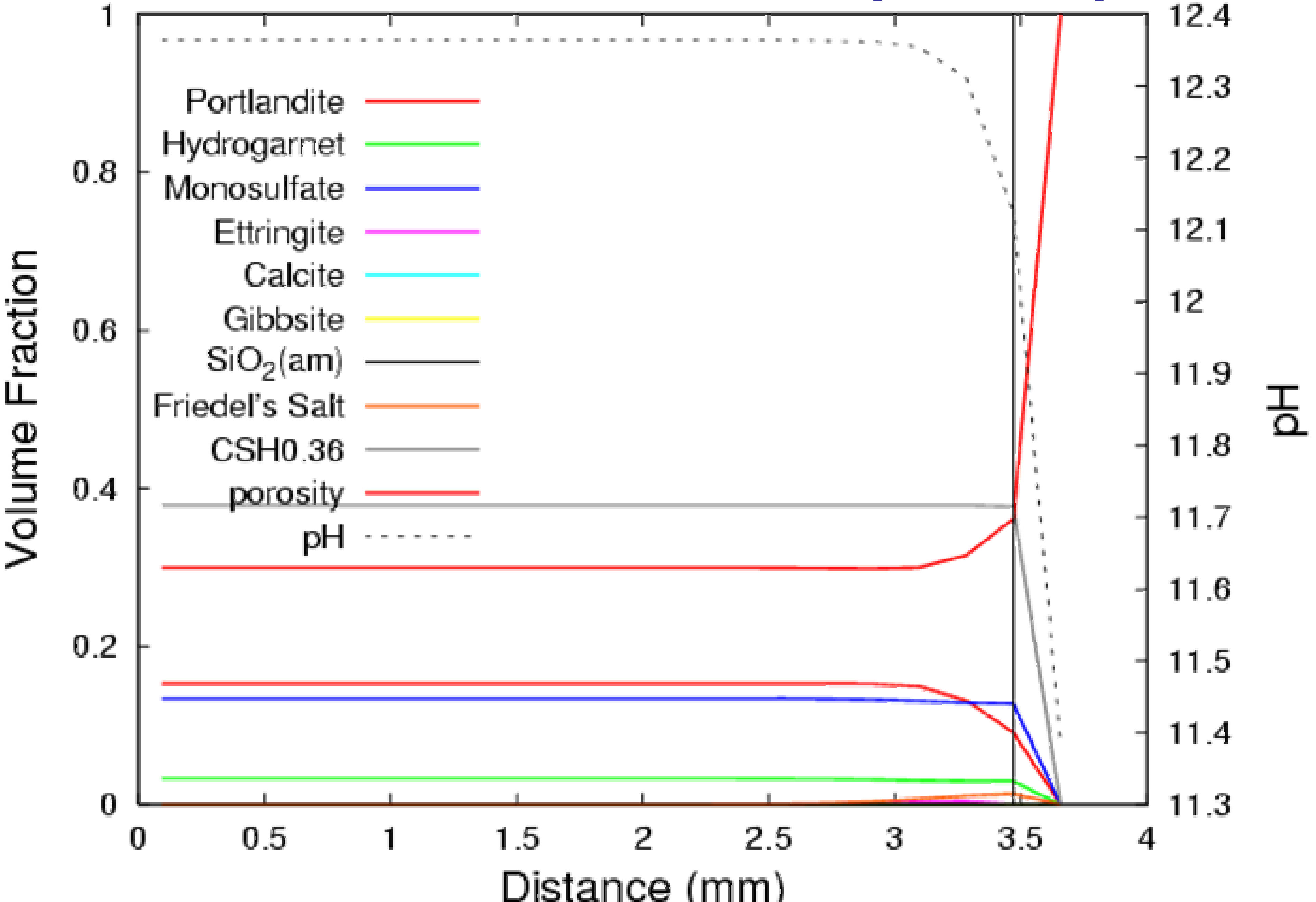
Species Dependent Diffusion



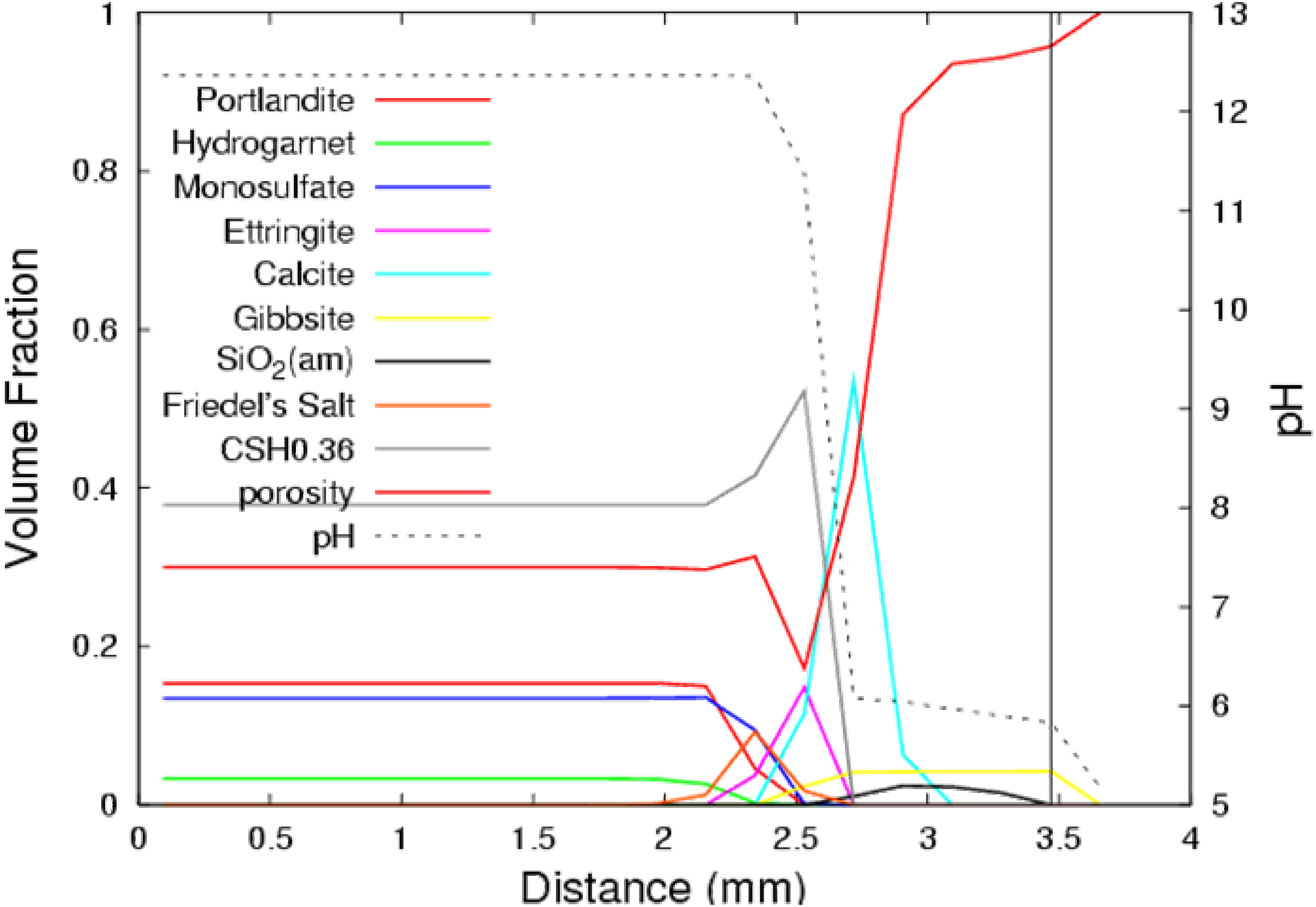
Simulation of Duguid/Scherer Experiments

- Similar setup to SACROC simulations
- 1-D diffusion of acid-CO_2 solution
- Initial cement porosity 30%
- Bounded by a single fluid-only node (100% porosity)
- Varied tortuosity and reaction rates to achieve qualitative agreement with mass-loss from rods

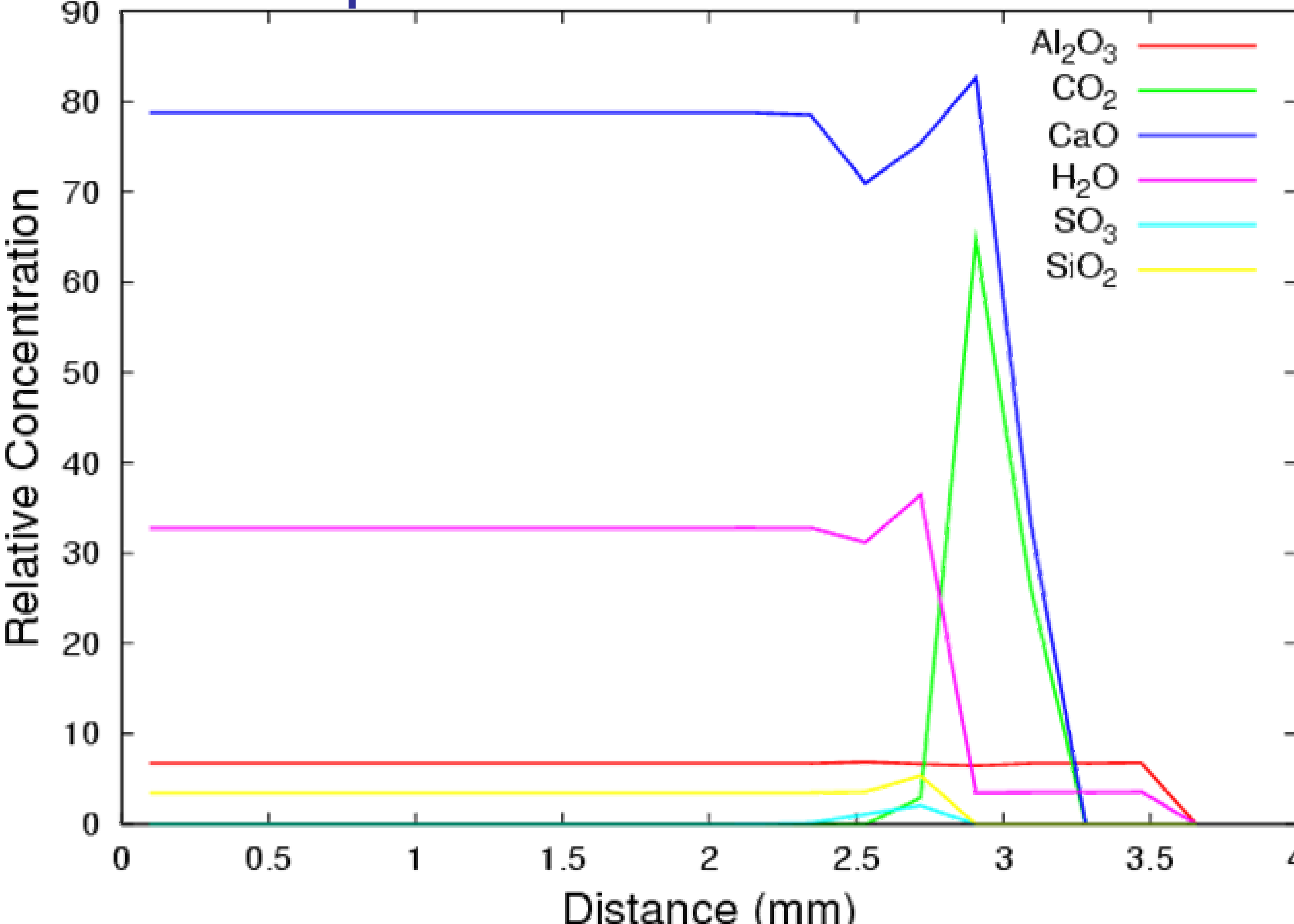
Cement Rod Phases (case 5)



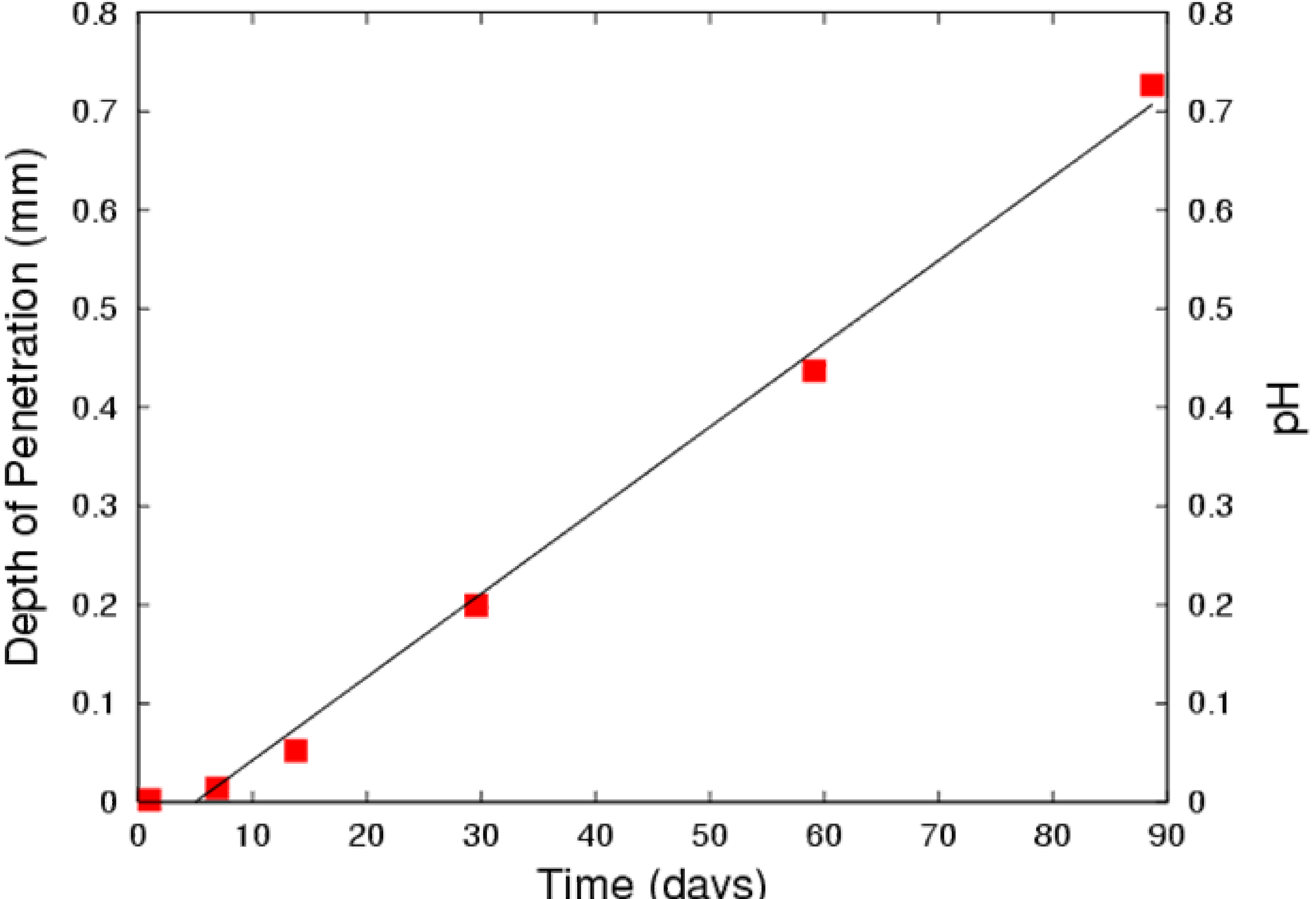
Cement Rod Phases (case 15)



Composition of Cement Rod

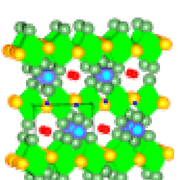


Mass loss of Cement Rod



Conclusions

- Diffusion-based models capture key features of cement degradation
- System behavior is a sensitive function of tortuosity and reaction rate
- Much higher (1000X) rates and much higher tortuosity (100X) necessary to explain depth penetration of 1 atm acid experiments
  - pH typically accelerates rates $\propto pH^{0.5}$
  - Tortuosity strong function of age, w/c
- Model sensitivity to pH primarily in rates, not effects
- Confining pressure may allow reaction products to precipitate in place (orange zone)



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Cement Issues

- Use numerical modeling to integrate experimental observations at various temperature, pressure, and fluid/rock with field constraints
- Translation of cement degradation into effective leak rates:
  - Fracture versus matrix vs annulus flow
  - Self-sealing or self-propagating interfaces
- Interplay with casing corrosion
- Geomechanical studies limited (fracture development and propagation, micro-annuli)

Funding Acknowledgements: DOE's National Energy and Technology Laboratory, the Los Alamos LDRD program and the Zero Emission Research & Technology project

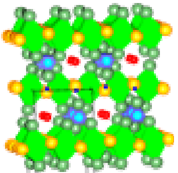
Colleagues at LANL: Marcus Wigand, Hari Viswanathan, and Phil Stauffer

Colleagues at Kinder Morgan CO_2: Scott Wehner and Mike Raines

Tortuosity vs Reaction Rate

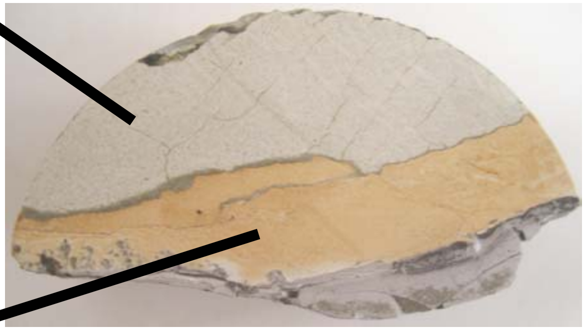
Tortuosity / Rates	High	Low
Fast	Steep reaction front, low penetration	Steep reaction front, deep penetration
Slow	Variable mineralogical profile	Uniform Profile

Cross-Section Through Well-Bore: 49-6



Air-Permeability Measurements of Cement and Shale in milliDarcy

Zone	Air Dried (mD)	Oven Dried (mD)
Upper Cement	0.09	74.00
Gray Zone C		0.10
Gray Zone A1	0.09	38.54
Gray Zone A2	0.07	48.22
Gray Zone A3	0.11	18.94
Gray Zone B1		5.75
Gray Zone B2		3.33
Gray Zone B3		8.40
Orange Zone A1	0.38	0.43
Orange Zone A2	0.19	0.19
Orange Zone A3	0.11	0.05
Orange Zone B1		0.17
Orange Zone B2		0.14
Orange Zone B3		0.22
Orange Zone B4		1.22
Shale along layers		8.57



Measurements courtesy of Bob Svec, New Mexico Tech

Development of a geochemical code to assess cement reactivity in CO2/brine mixtures.

Bruno Huet, Andrew Duguid, Richard Fuller,
Jean Prevost, George Scherer
(Princeton University)
Contributor: Jim Johnson (LLNL)

Introduction

Background:

Provide a solution for the reduction of global warming associated with the increased CO_2 content in the atmosphere.

Storage of CO2 in deep geological formation:

- depleted oil and gas reservoir,
- deep saline aquifer.

Objective of this work:

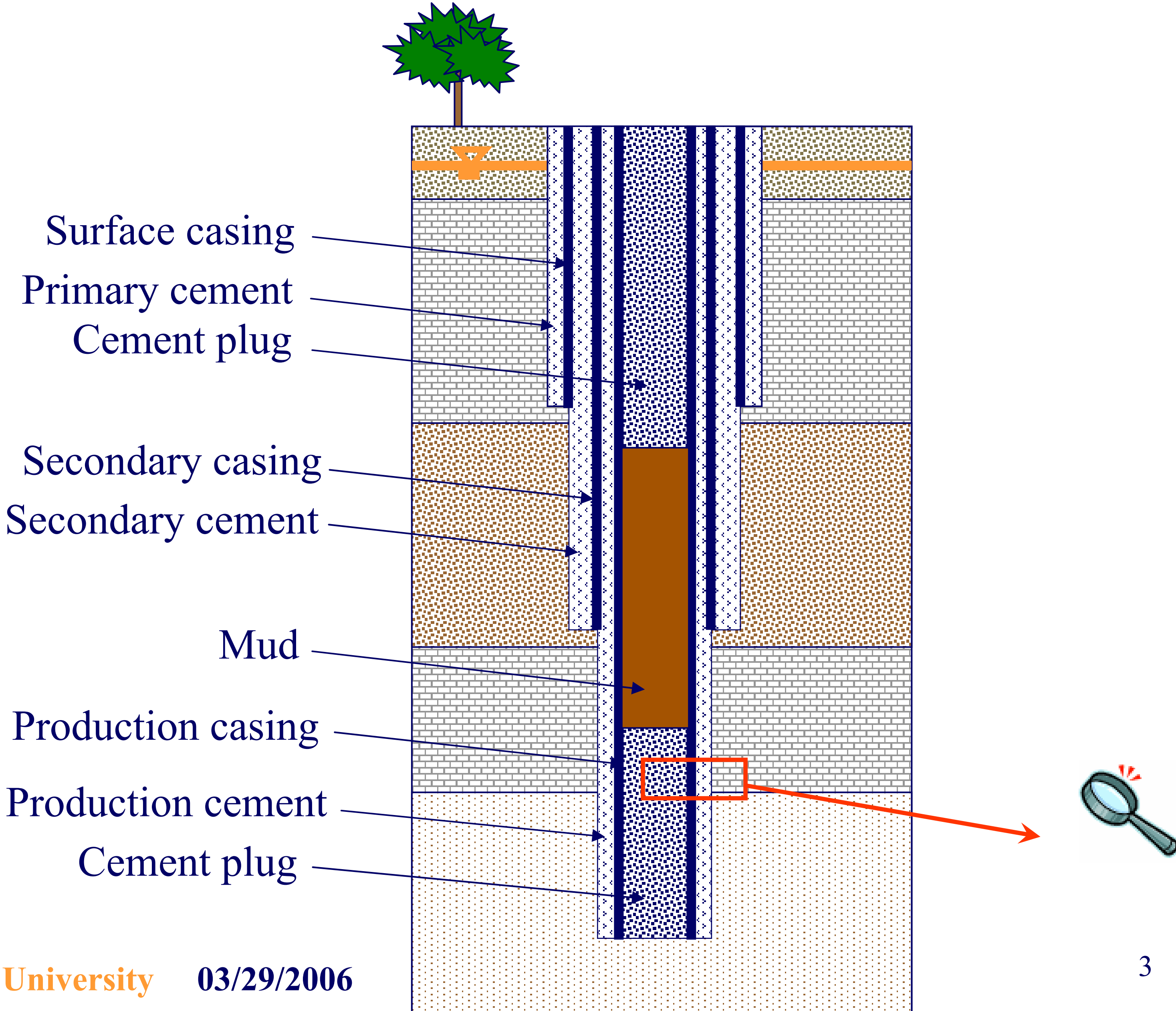
Assess the reliability of the CO2 storage with time.

1. Reliability of geological formation limited by the presence of engineered high permeability path (well bores).

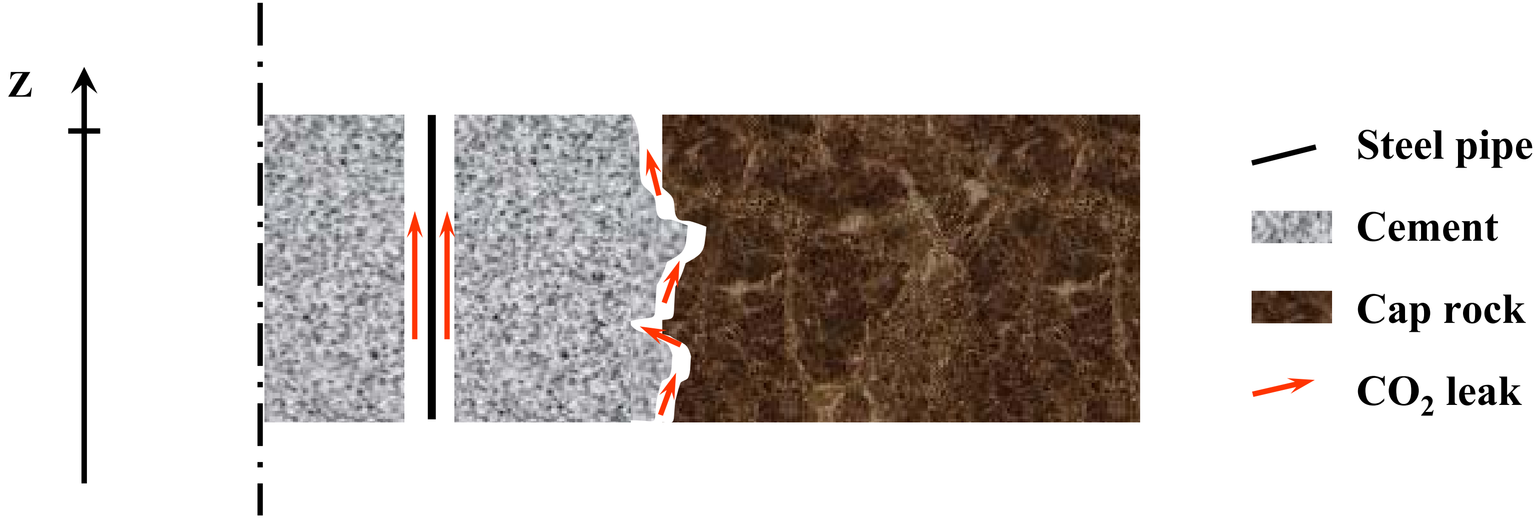
2. Degradation of casing materials (steel, cement) may increase the CO2 leak with time.

Coupled modeling and experimental approach

Sketch of a typical abandoned oil well



Possible CO_2 leaks along high-permeability path



Three main mechanisms (P, T dependent):

1. Multiphase transport within annulus: aqueous phase and CO_2 rich phase (supercritical/liquid/gas)
2. Reactivity of cement : CO2 brine (pH=3), cement pore solution (pH=13)
3. Interface behavior: coupling of 1. and 2.

Sealing or widening of the annulus ?

Need for a coupled geochemical transport model

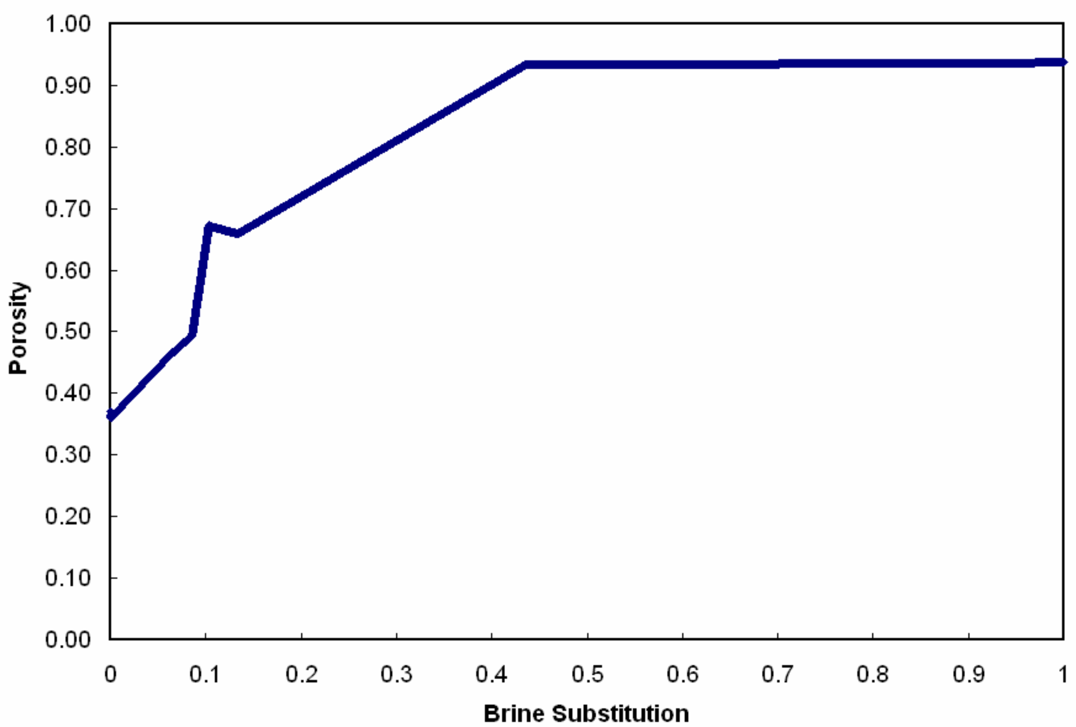
Chemistry approach

Batch experiments simulation:

➡ Flush of cement with CO2 saturated sea water.

✓ Cement = Portlandite + Jennite + Ettringite + Monosulfoaluminate + dissolved NaOH (0.25M)

✓ Sea water = NaCl (0.5 M), CO_2 (1 bar)



Reactive Transport of Ions in Cement-Based Porous Material [1]:

1. Transport of aqueous species (for each ion):

$$\frac{\partial(\theta C_i^0)}{\partial t}-\frac{\partial}{\partial x}\left(\underbrace{\theta D_i \frac{\partial C_i^0}{\partial x}}_{\text{I. Diffusion}}+\underbrace{\theta C_i^0 \frac{D_i z_i F}{RT}\frac{\partial \psi}{\partial x}}_{\text{II. Electrical coupling}}+\underbrace{\theta D_i C_i^0 \frac{\partial \ln \gamma_i}{\partial x}}_{\text{Activity correction}}+\underbrace{D_i C_i^0 \frac{\partial \theta}{\partial x}}_{\text{Porosity correction}}\right) \quad , i \in \{1, N_{sp}\}$$

2. Local equilibrium:

Heterogeneous reactions: e.g. $Ca(OH)_2 \Leftrightarrow Ca^{2+} + 2\,OH^-$

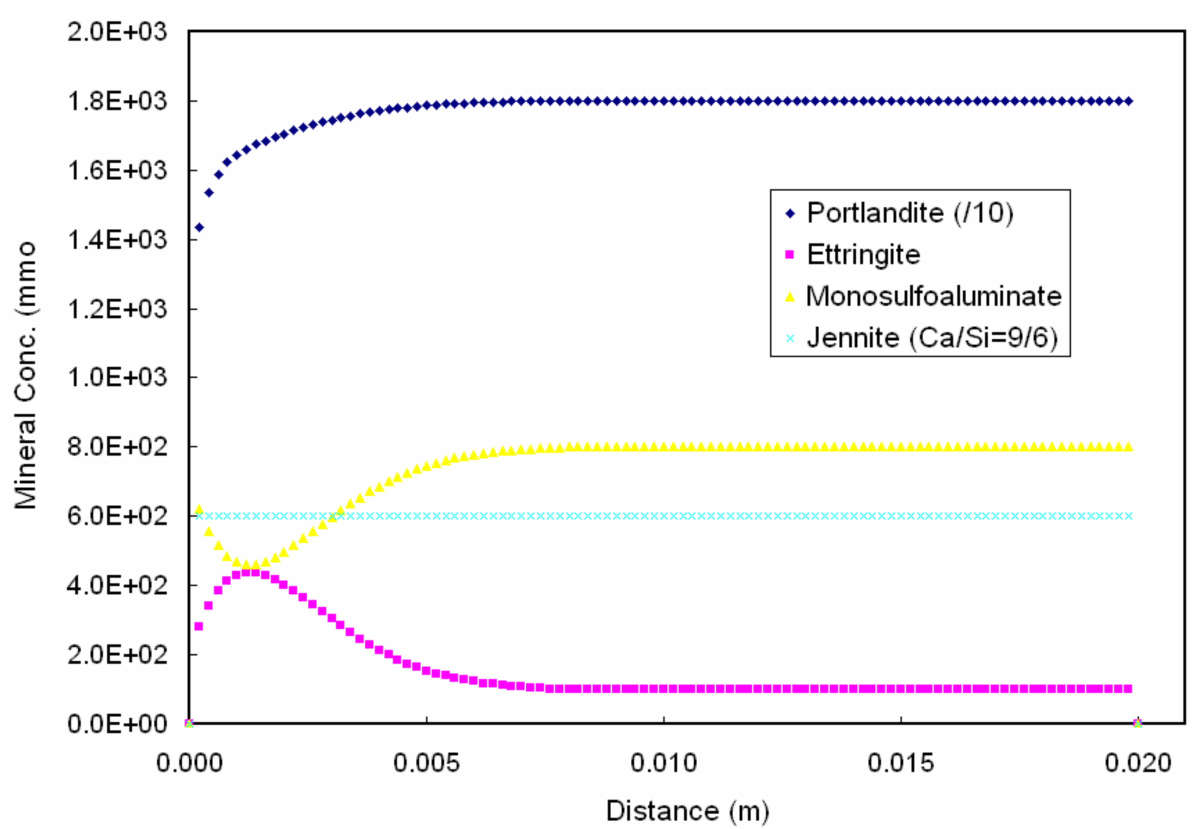
$$\sum_{j=1}^{N_c} \nu_{ij}\left(Log(\gamma_j)+Log\left(C_j^0+\sum_{k=1}^{M}\nu_{jk}\,\Delta S_k\right)\right) + Log(K_{fi}) = 0 \quad , i \in \{1, M\}$$

[1]: E. Samson and J. Marchand, Université Laval, Québec, Canada G1K 7P4

Cement chemical behavior in pure de-ionized water

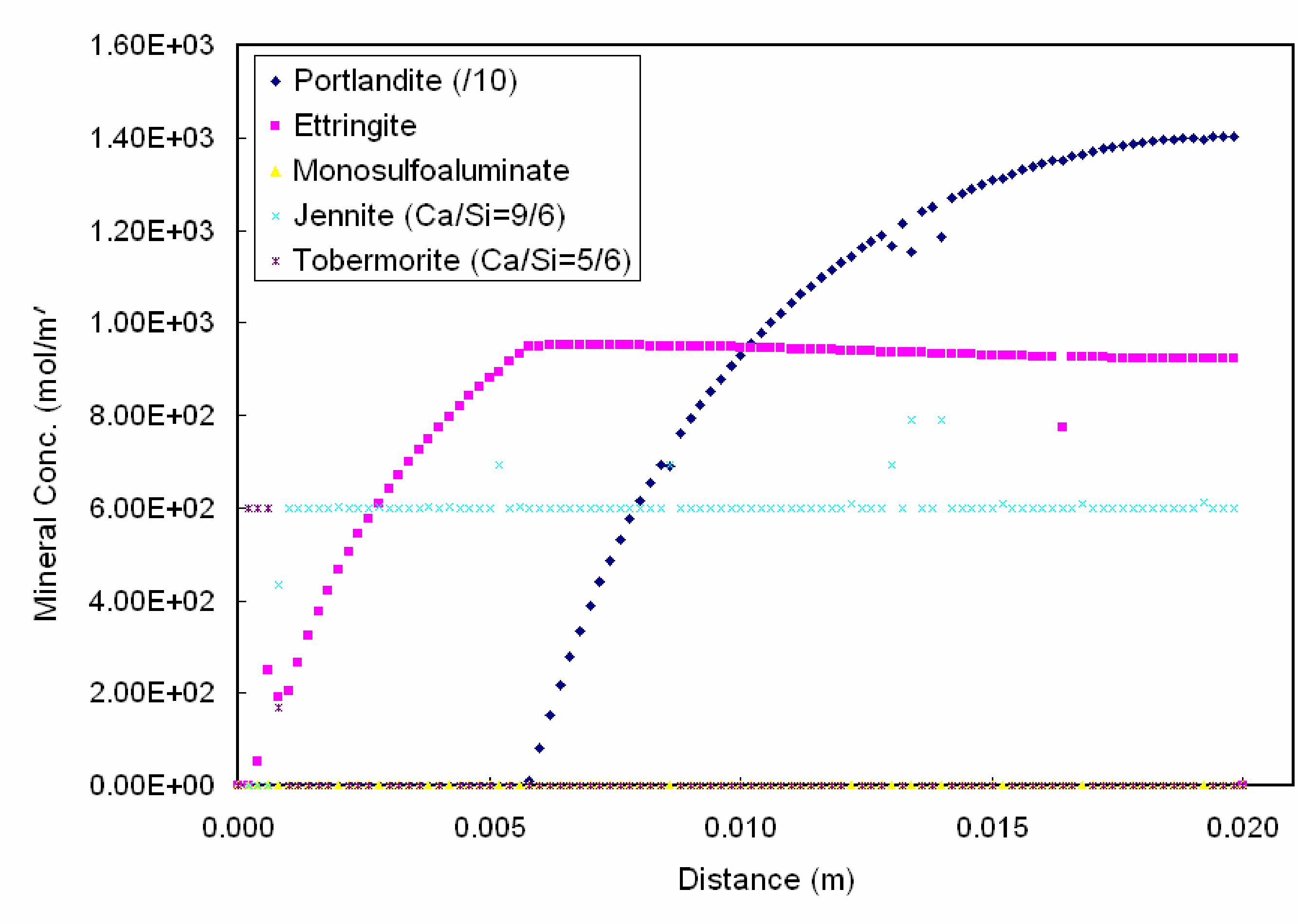
Mineral profile (after 6 days):

I. Diffusion term, II. Electrical coupling term, III. Activity correction term



Cement chemical behavior in pure de-ionized water

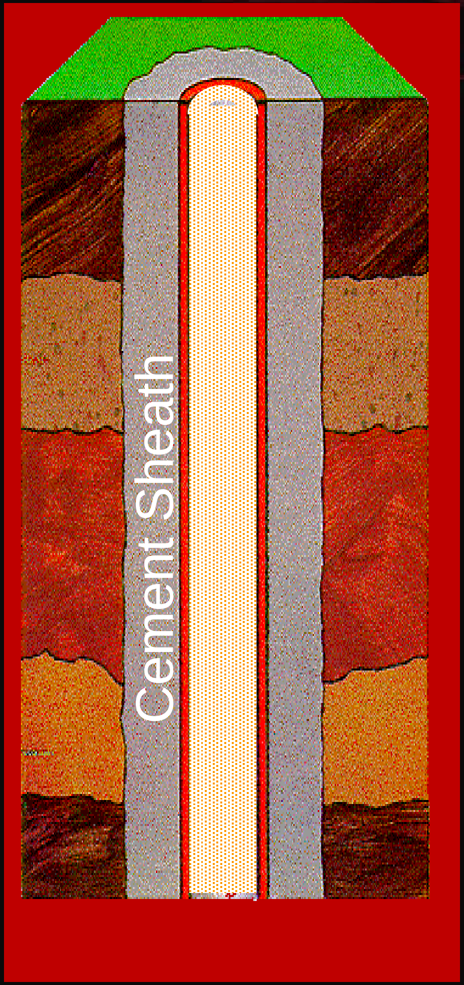
Mineral profile (after 4 months):



Current and Future Work

- Integrating homogeneous chemistry
- Temperature
- Improved description of C-S-H (logK = f (Ca/Si)
- Reaction Kinetics (needed for CSH with low Ca/Si ratio)

- Coupling with multiphase transport (PU flash)
- 2D – simulations of CO_2 leak up the wellbores



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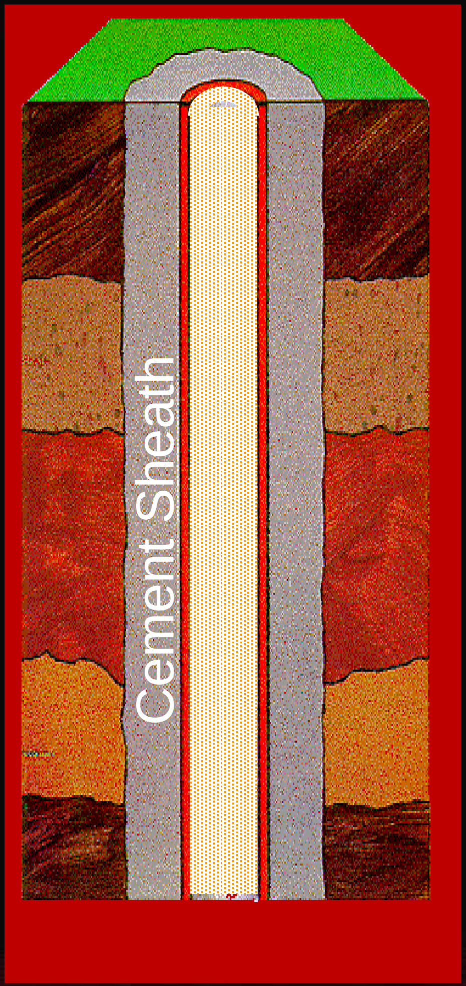
Sustained Casing Pressure

- **Cement slurry**
  - Hole cleaning
  - Prevent losses
  - Cement slurry placement
- **Cement Sheath & Casing**
  - Well operations
  - Downhole conditions

Effect on Cement Sheath & Casing

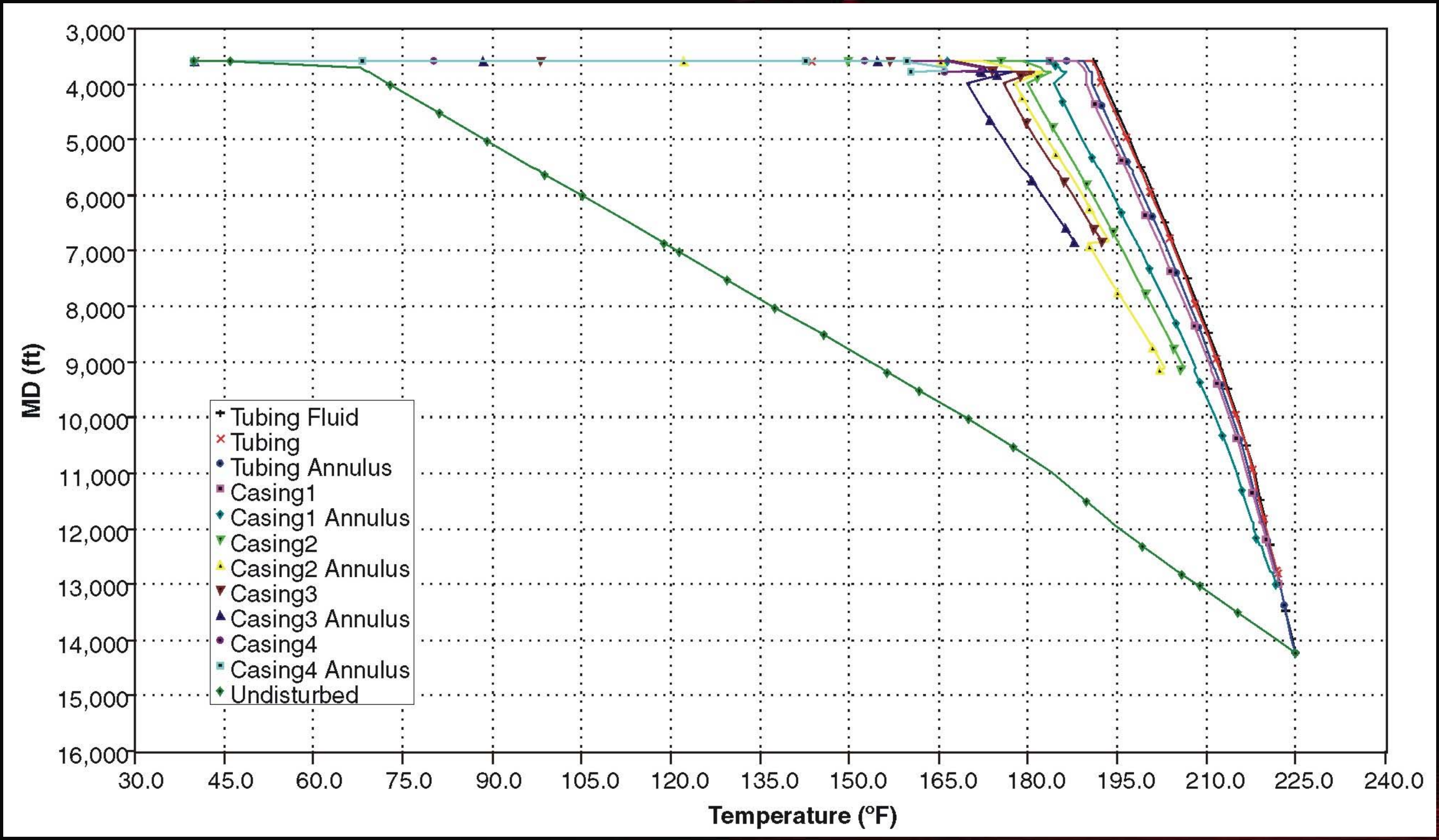
- **Well operations**
  - **pressure testing**
  - **hydraulic stimulation**
  - **production**
  - **Injection**
  - **….**
- **Downhole**
  - **Chemicals**
    - **CO_2**
    - **chlorides**
    - **pressure**
    - **temperature**
    - **…..**



Well Events After Primary Cementing

- Cement slurry hydration
  - & hydration volume reduction
- Completions
  - & pressure decrease inside the casing
- Pressure testing
  - & pressure increase inside the casing
- Hydraulic fracturing
  - & pressure increase
- Production
  - & pressure/temperature increase inside tubular

Temperature Simulation



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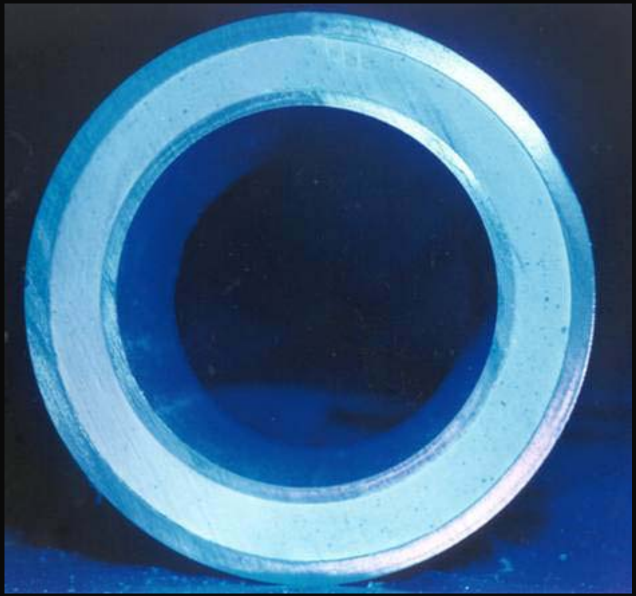
Damaged Cement Sheath

Lab Test

Resilient Sheath – No Damage



avi file

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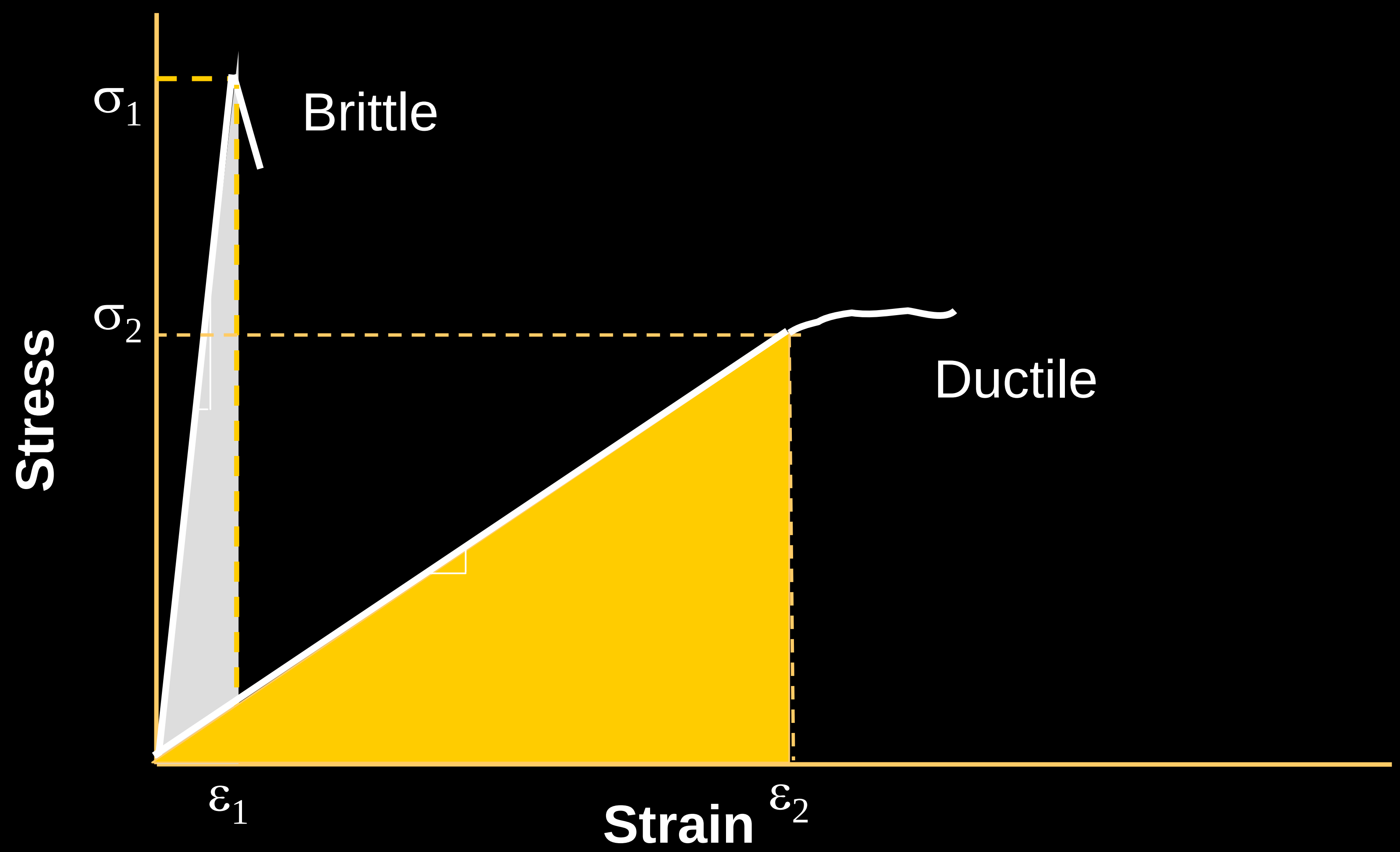
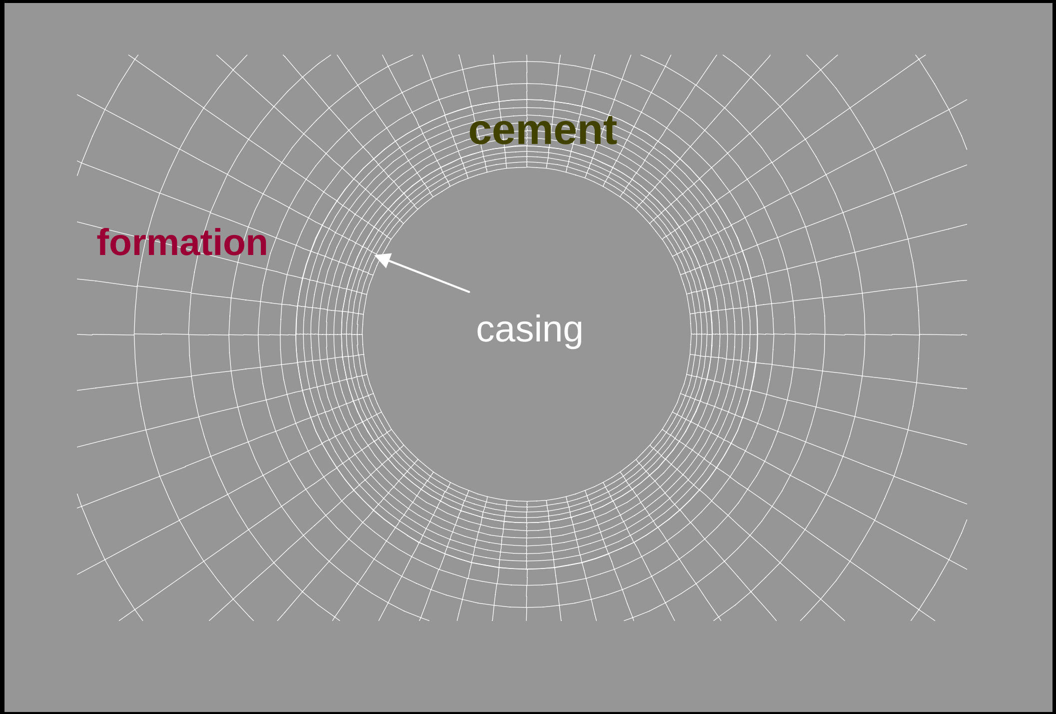
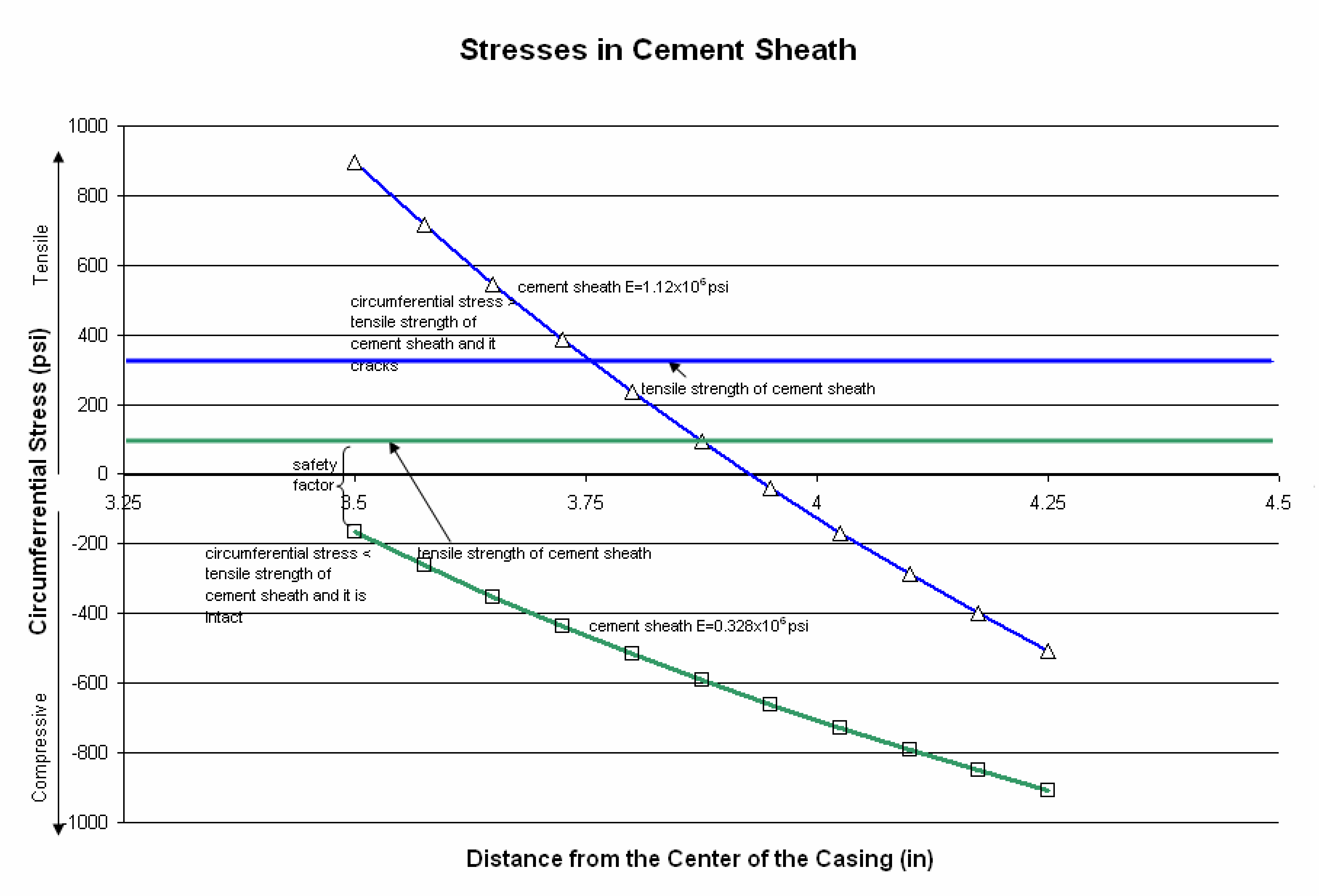
Material Strength and Deformation

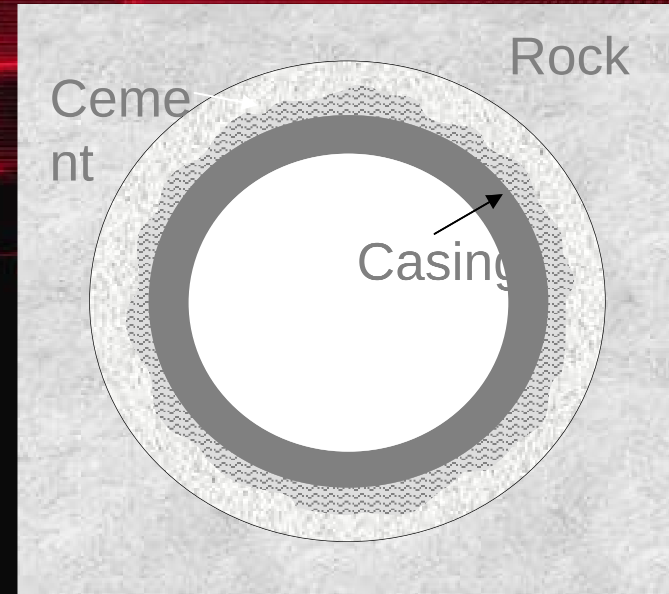


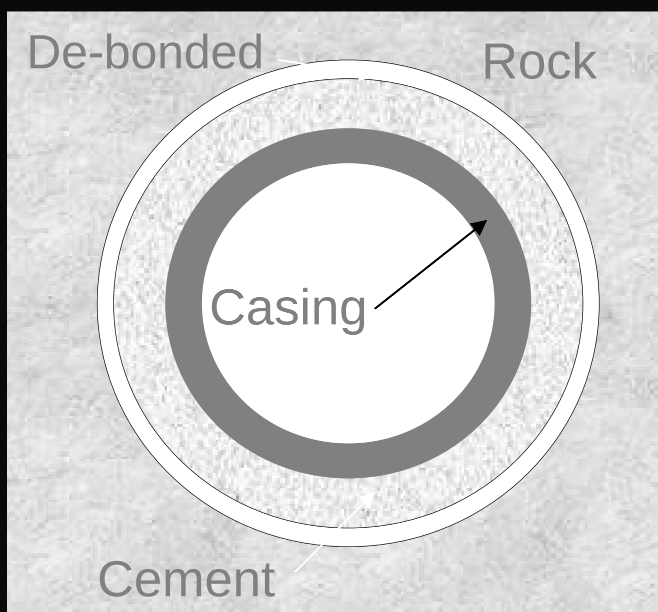
Analysis

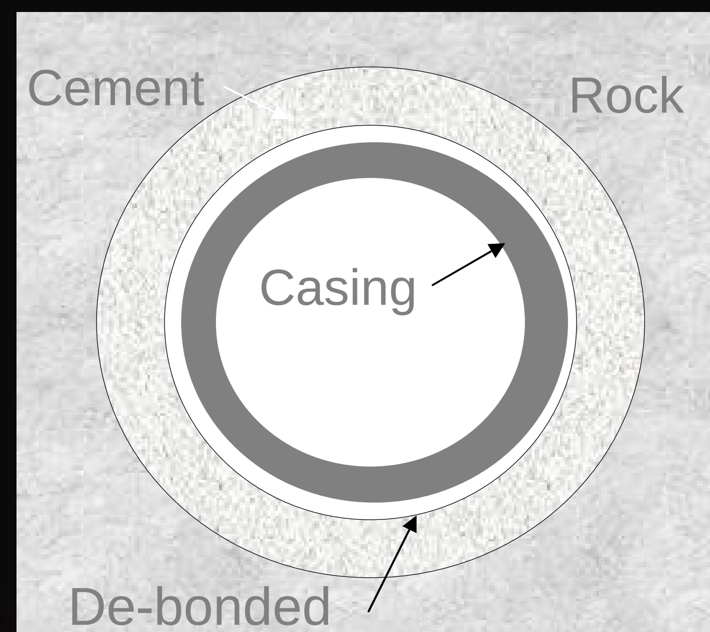




Stresses in Cement Sheath
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
3.25
3.5
3.75
4
4.25
4.5
Tensile
Compressive
Circumferential Stress (psi)
cement sheath E=1.12x10^6 psi
circumferential stress > tensile strength of cement sheath and it cracks
tensile strength of cement sheath
safety factor
circumferential stress < tensile strength of cement sheath and it is intact
tensile strength of cement sheath
cement sheath E=0.328x10^6 psi
Distance from the Center of the Casing (in)







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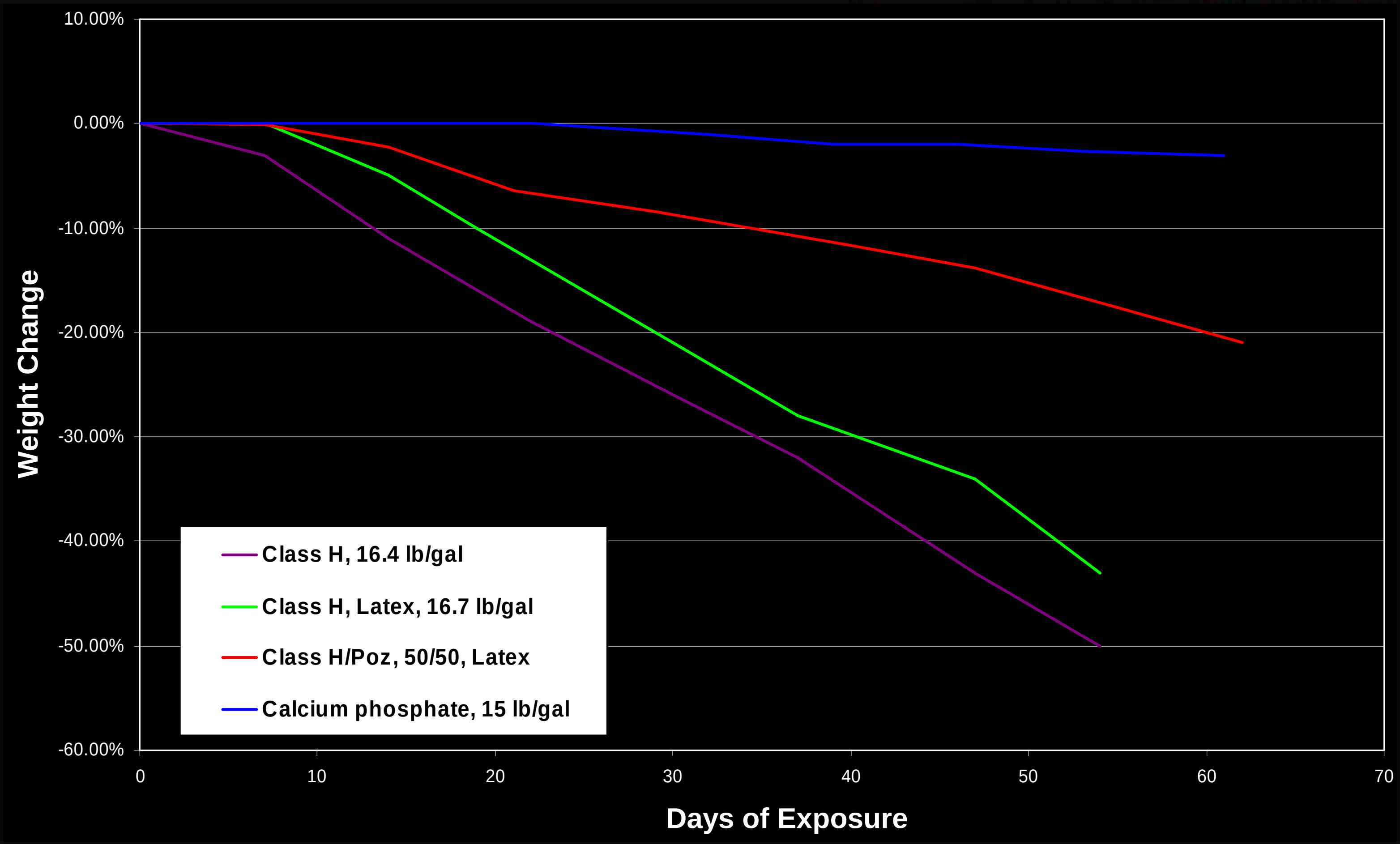
Effect of Acidic CO_2 Solution



*140˚F, 1% aqueous Na_2CO_3 solution acidified to pH 2 with H_2SO_4 in a sealed chamber to generated CO_2

Cement Sheath

- Curing
  - hydration volume reduction
- Mechanical properties
  - Young’s modulus
  - Poisson ratio
  - Tensile strength
  - Plasticity parameters

Summary

- Cement slurry
  - Hole cleaning
  - Prevent losses
  - Cement slurry placement
- Cement Sheath
  - Well operations
  - Downhole conditions

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Large-scale Modeling of Leakage along Wells

Michael A. Celia

Princeton University

<u>Collaborators:</u>

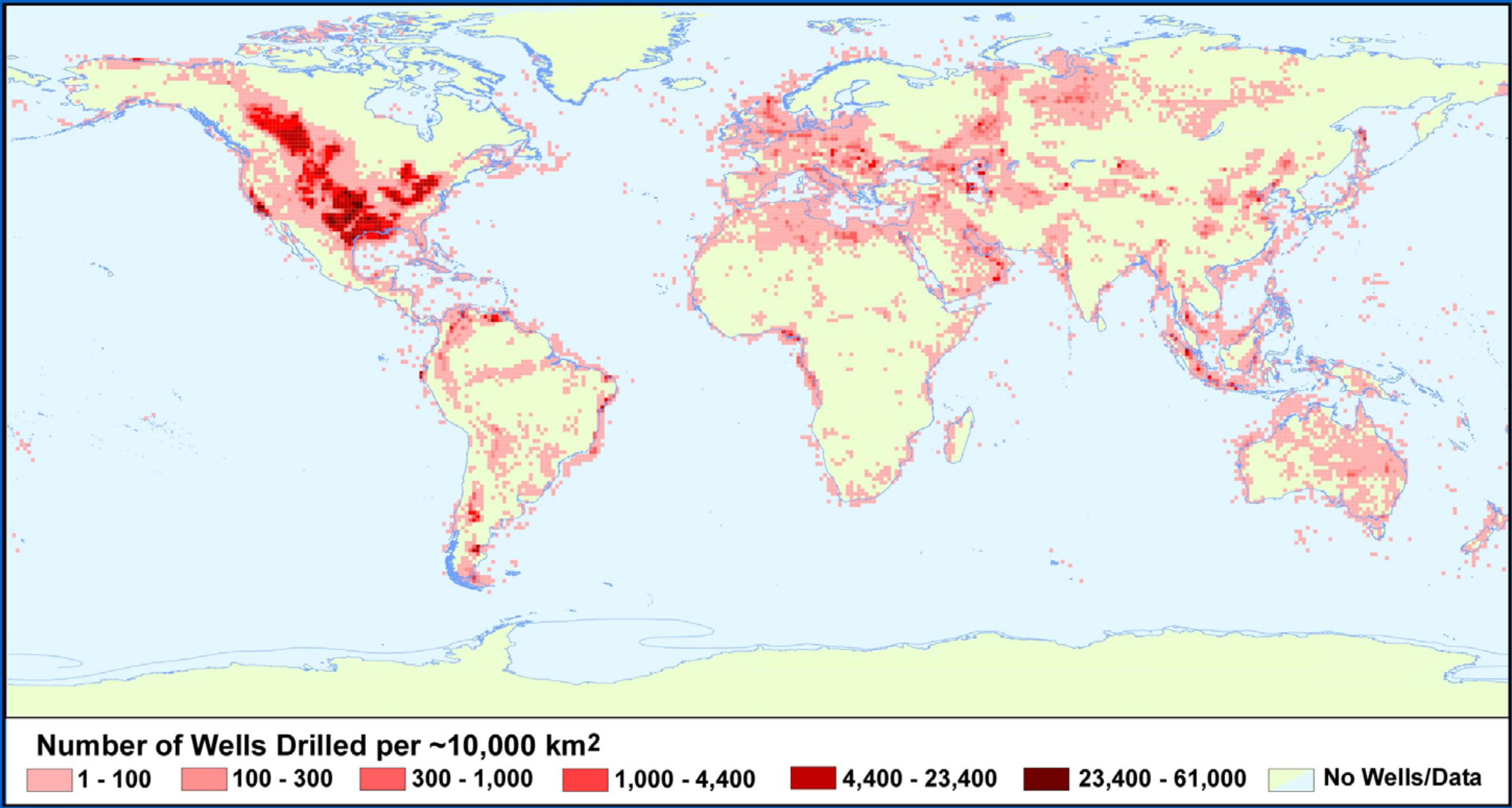
Stefan Bachu (*Alberta EUB*)

Jan Nordbotten (*U. Bergen and Princeton U.*)

Sarah Gasda (*Princeton U.*)

Dmitri Kavetski (*Princeton U.*)

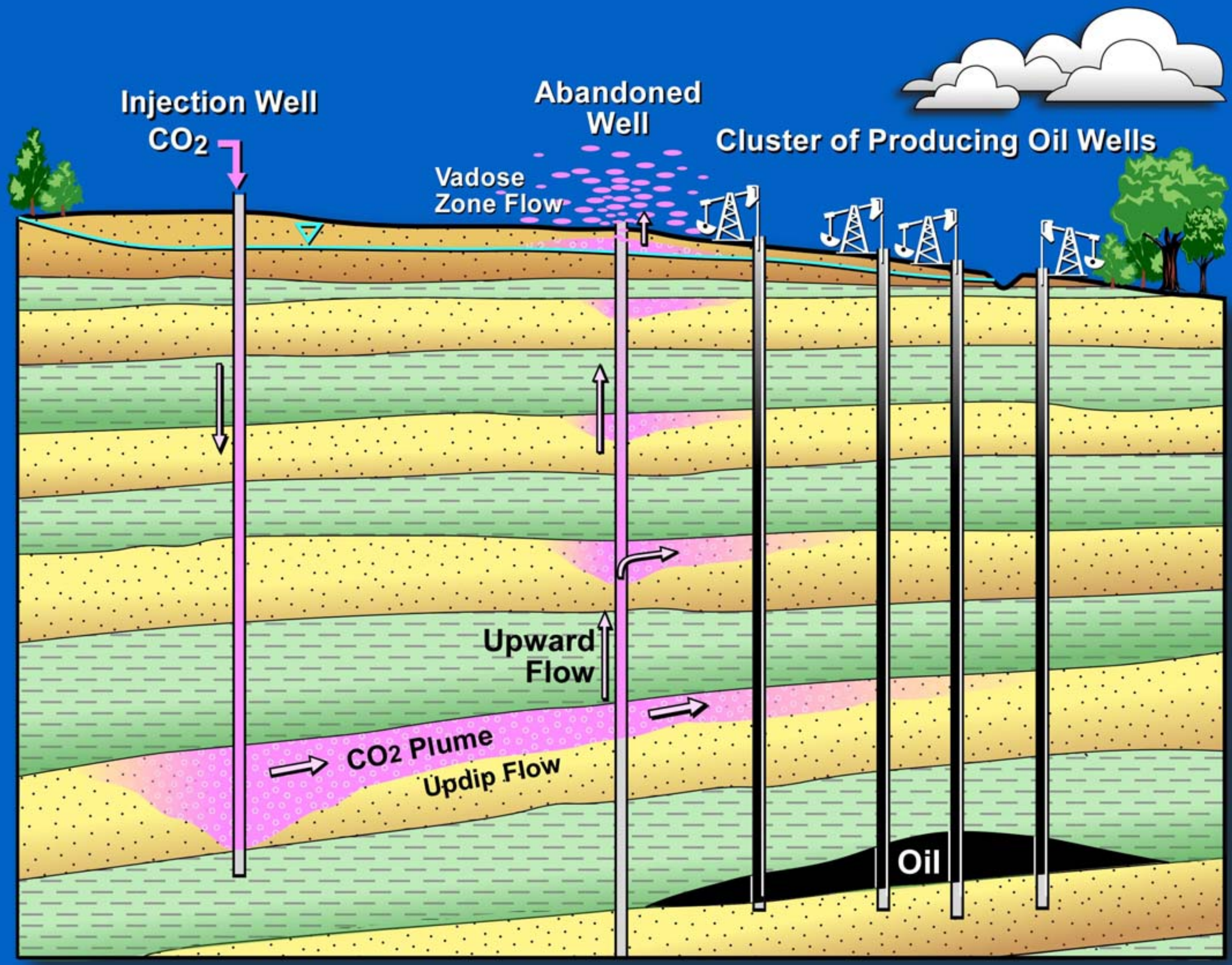
Worldwide Density of Oil and Gas Wells



End of 2004

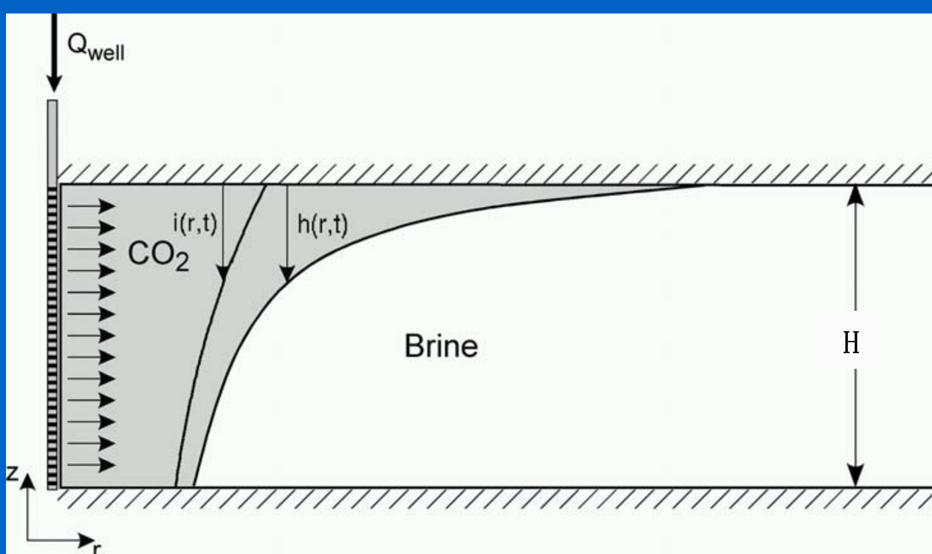
From IPCC SRCCS, 2005

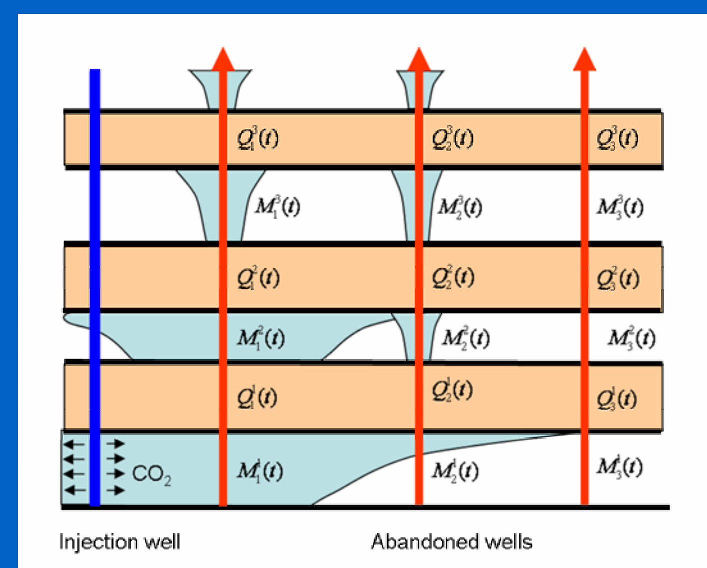
Potential CO_2 Migration and Leakage Paths



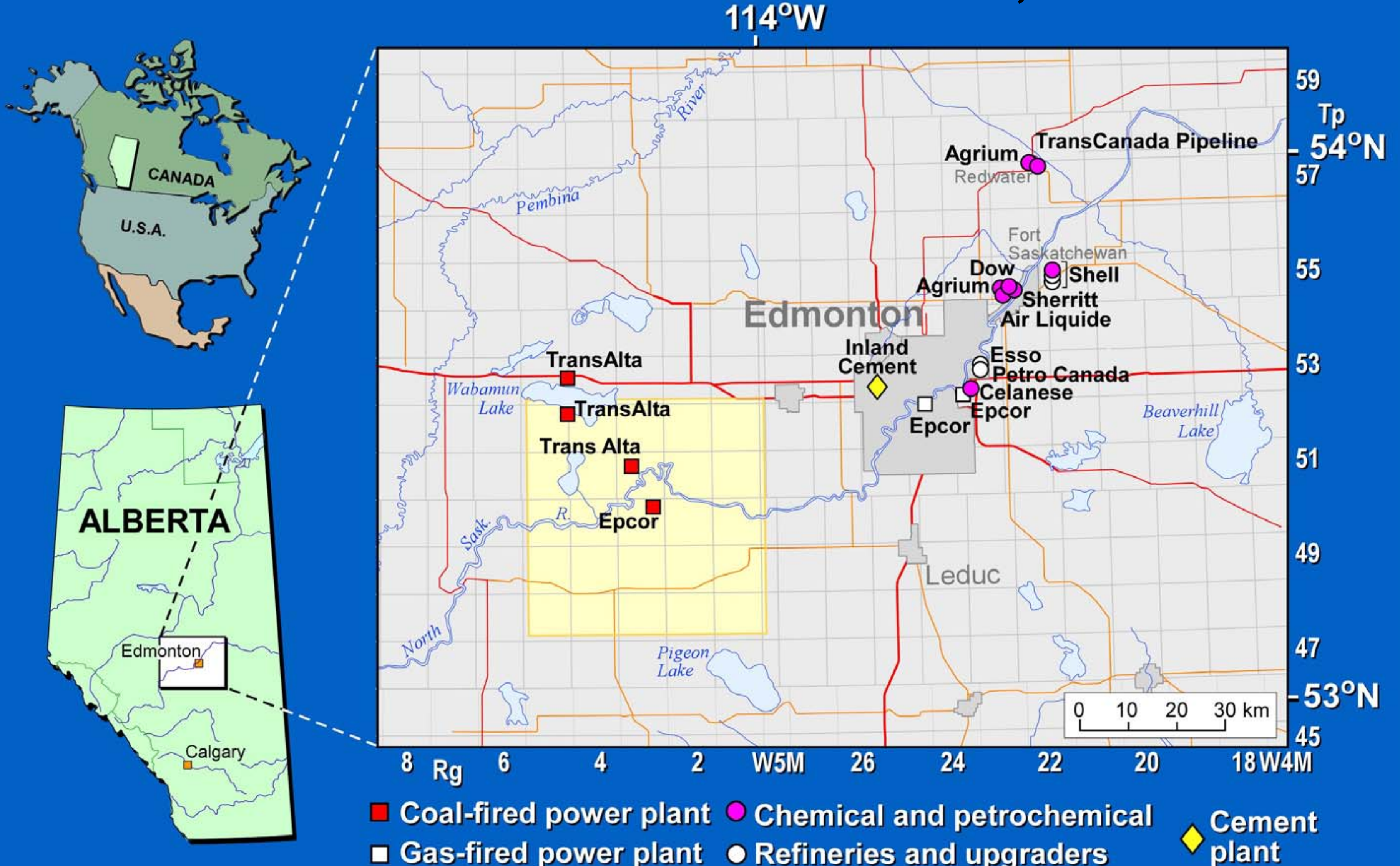
Components of the Semi-analytical Model

- **Injection plume evolution**
  - Similarity solution (Significant buoyancy; JFM Paper)
  - Radial Buckley-Leverett type solution (Viscous domination; TiPM Paper)
  - Includes drying fronts (JFM Paper)
- **Leakage Dynamics (ES&T, GHGT-7, and WRR Papers)**
- **Post-injection Redistribution**
  - Transition solution (Tech Note)
  - Later-time similarity solution (standard)
- **Upconing around Leaky Wells (Tech Note)**

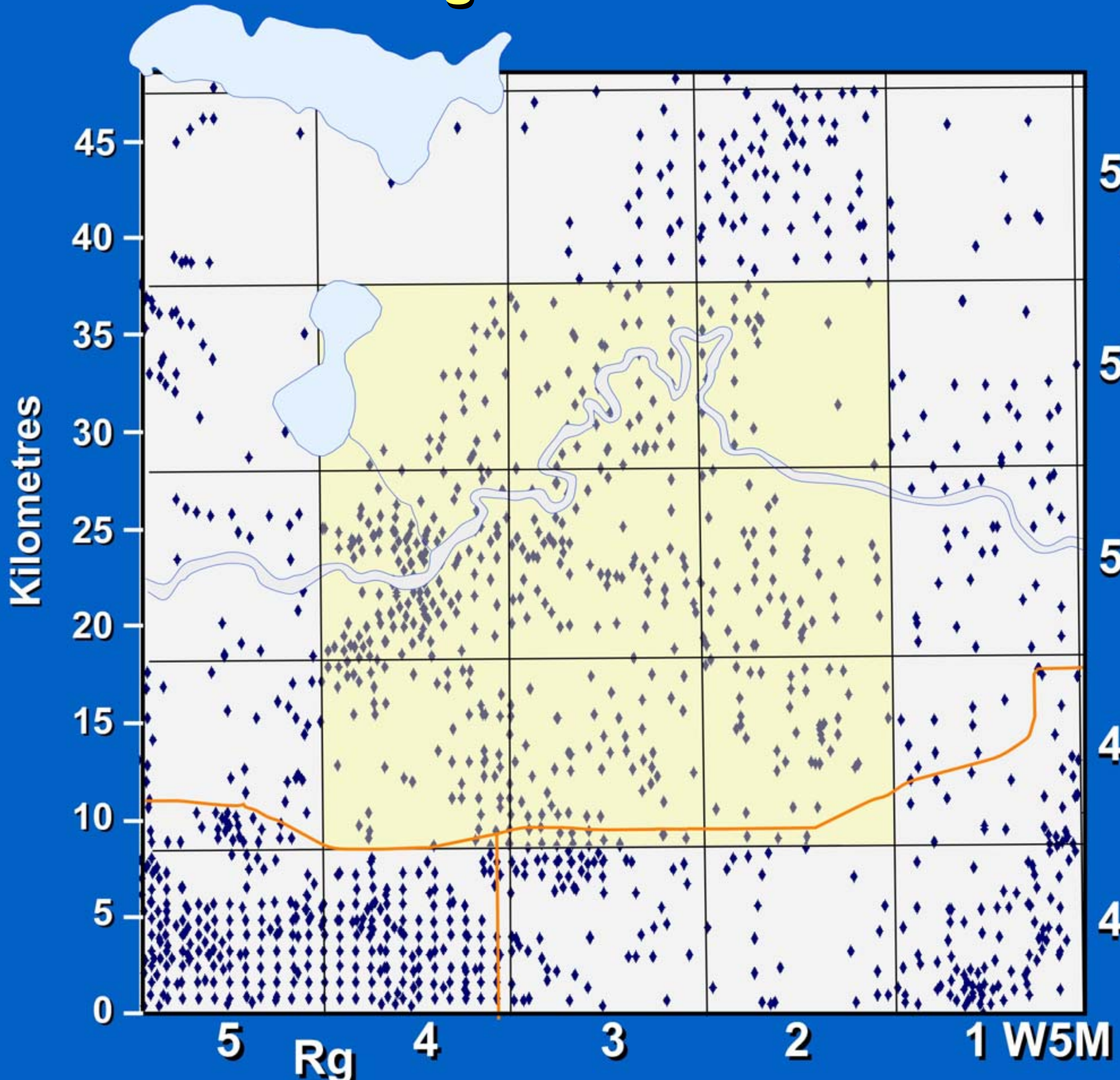




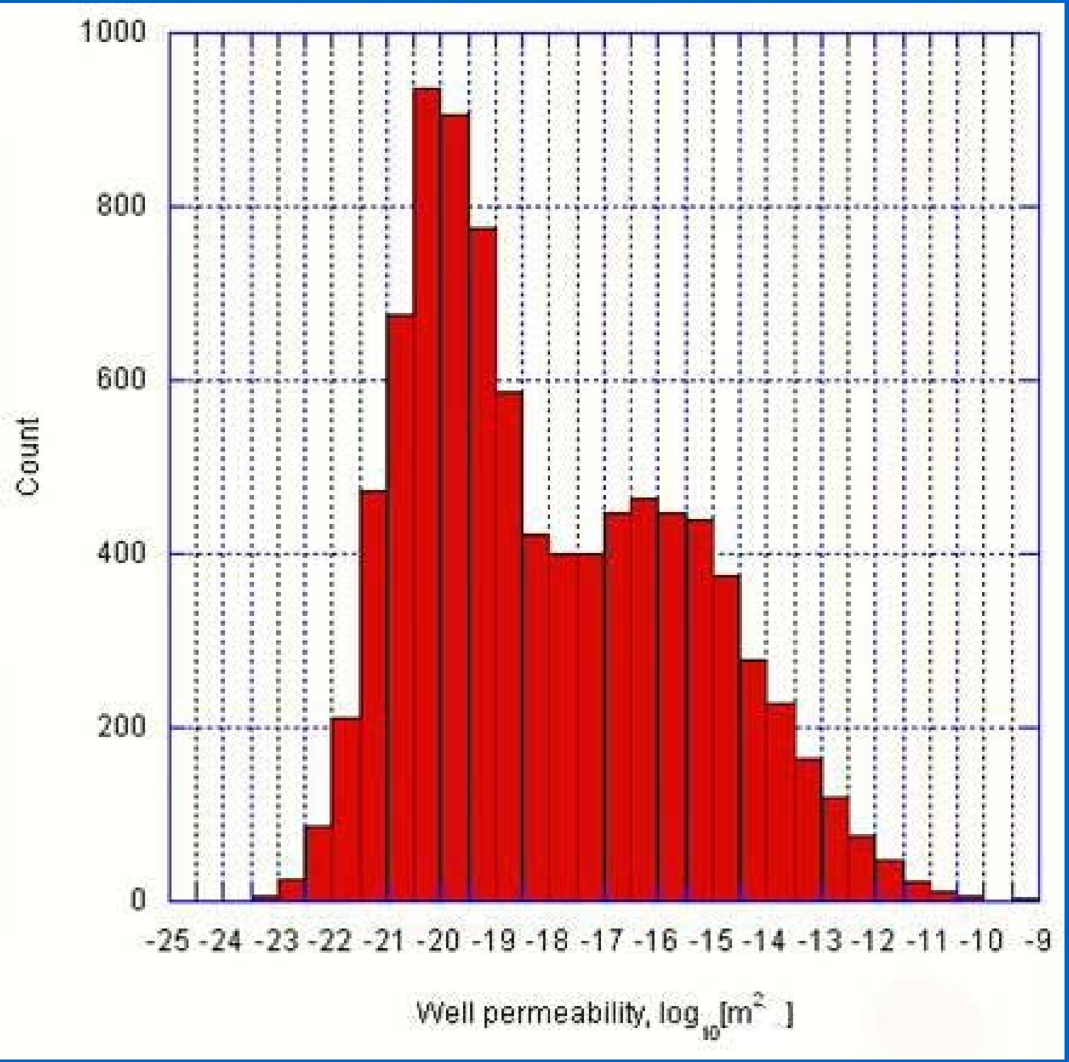
Location of Major CO_2 Sources in the Edmonton – Wabamun Lake Area, Alberta Basin



Distribution of Existing Wells in the Wabamun Lake Area



Probability Distribution for Well Permeabilities



Leakage Plumes in Bottom Layer (Run #1)

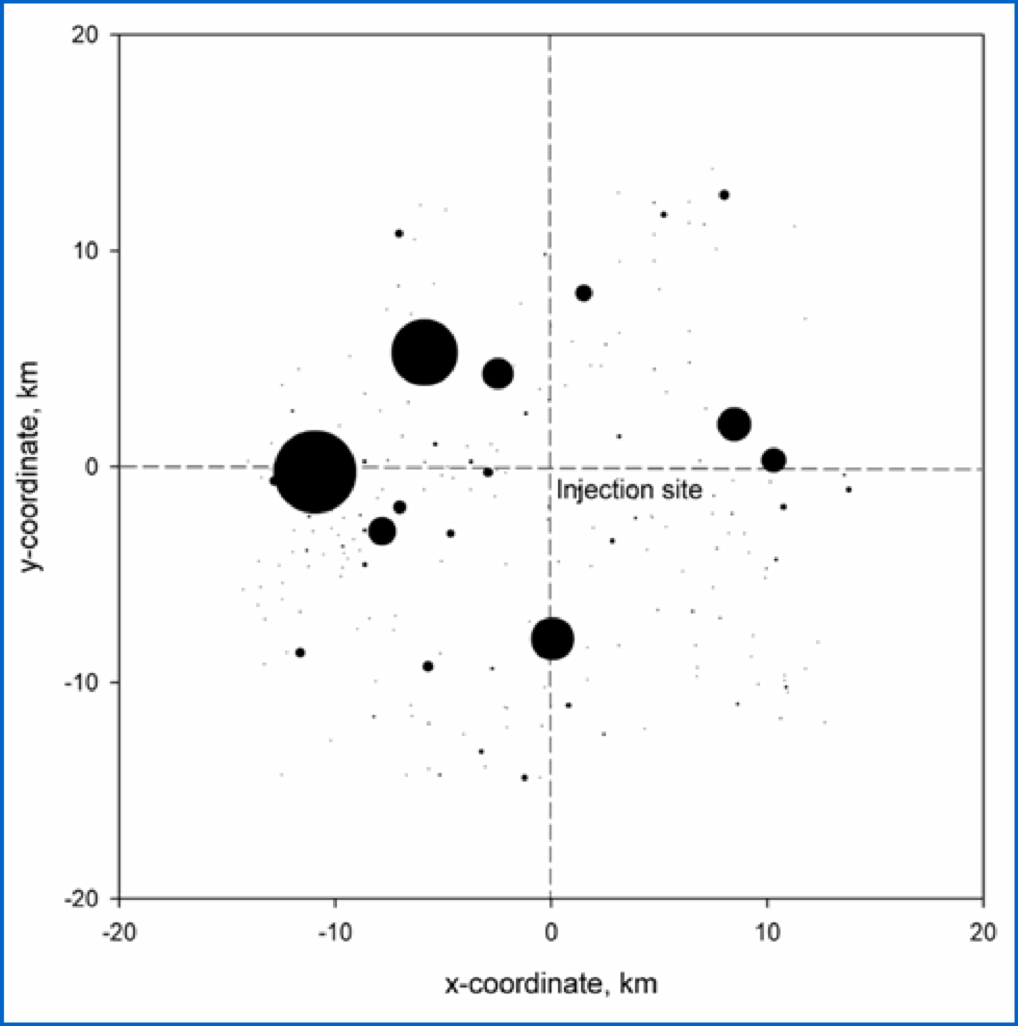
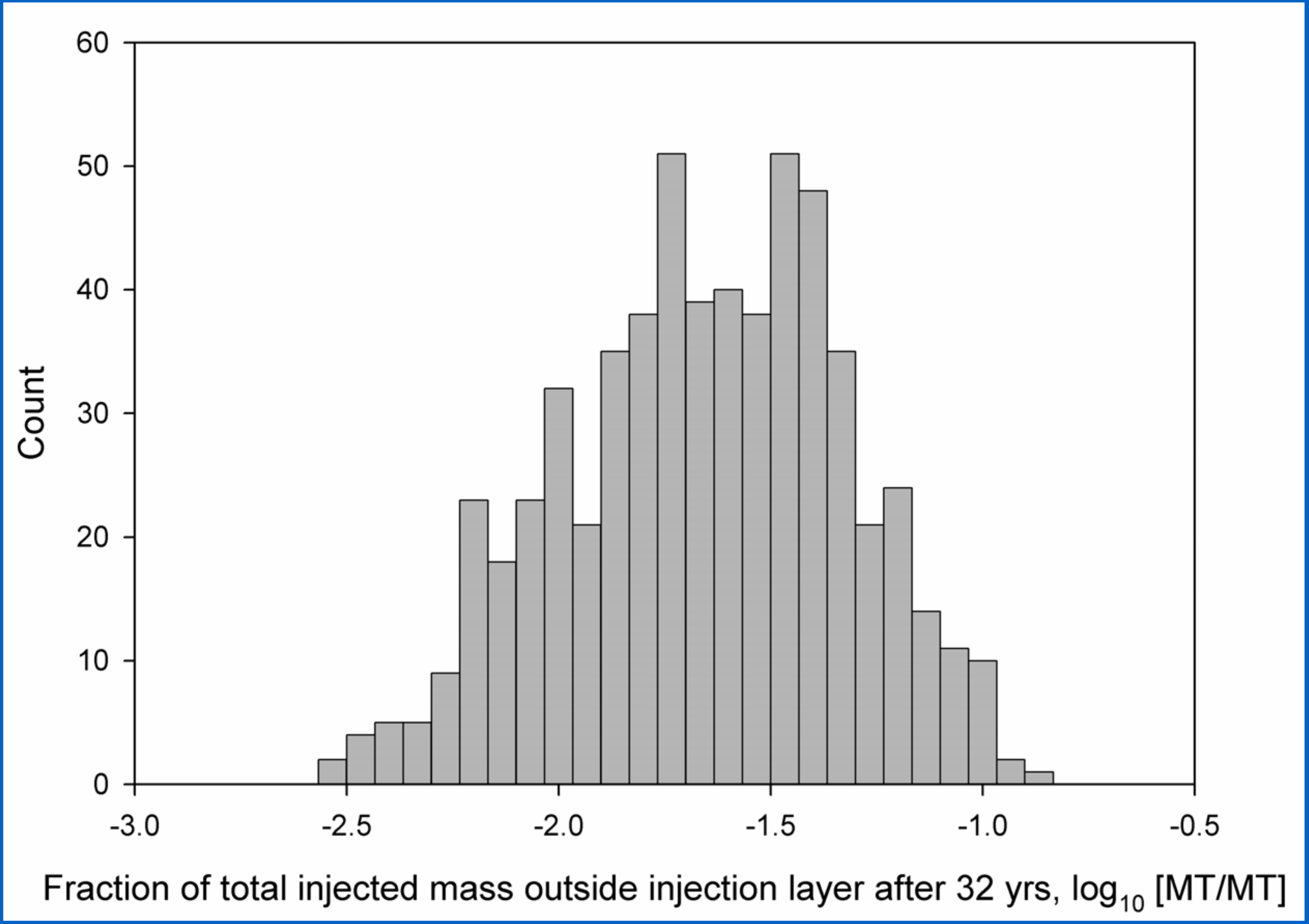


Figure 2: Plume migration in the layer above the injection formation after 32 years of injection. The x-y axes denote the spatial domain, centered on the injection site. The plumes are indicated by circles scaled by the plume size.

Histogram of Leakage over 600 Simulations



Conclusions

- Simulations need to be able to in include many wells and many geological layers.
- A Semi-analytical model allows Monte Carlo simulations for risk assessment.
- A comprehensive experimental program is needed to determine important properties of existing wells.

References (Well Leakage)

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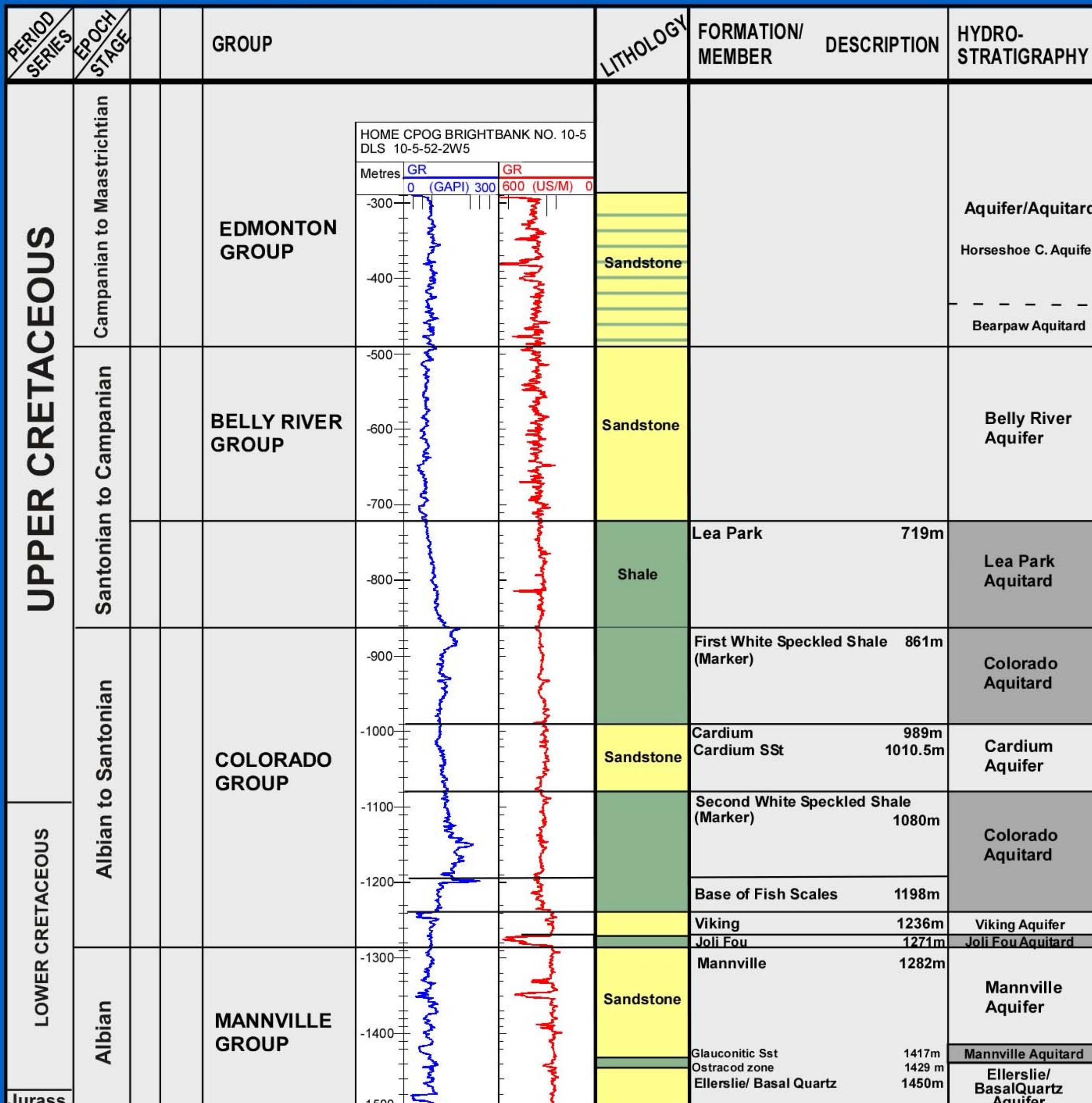
Location:00/10-05-052-2W5

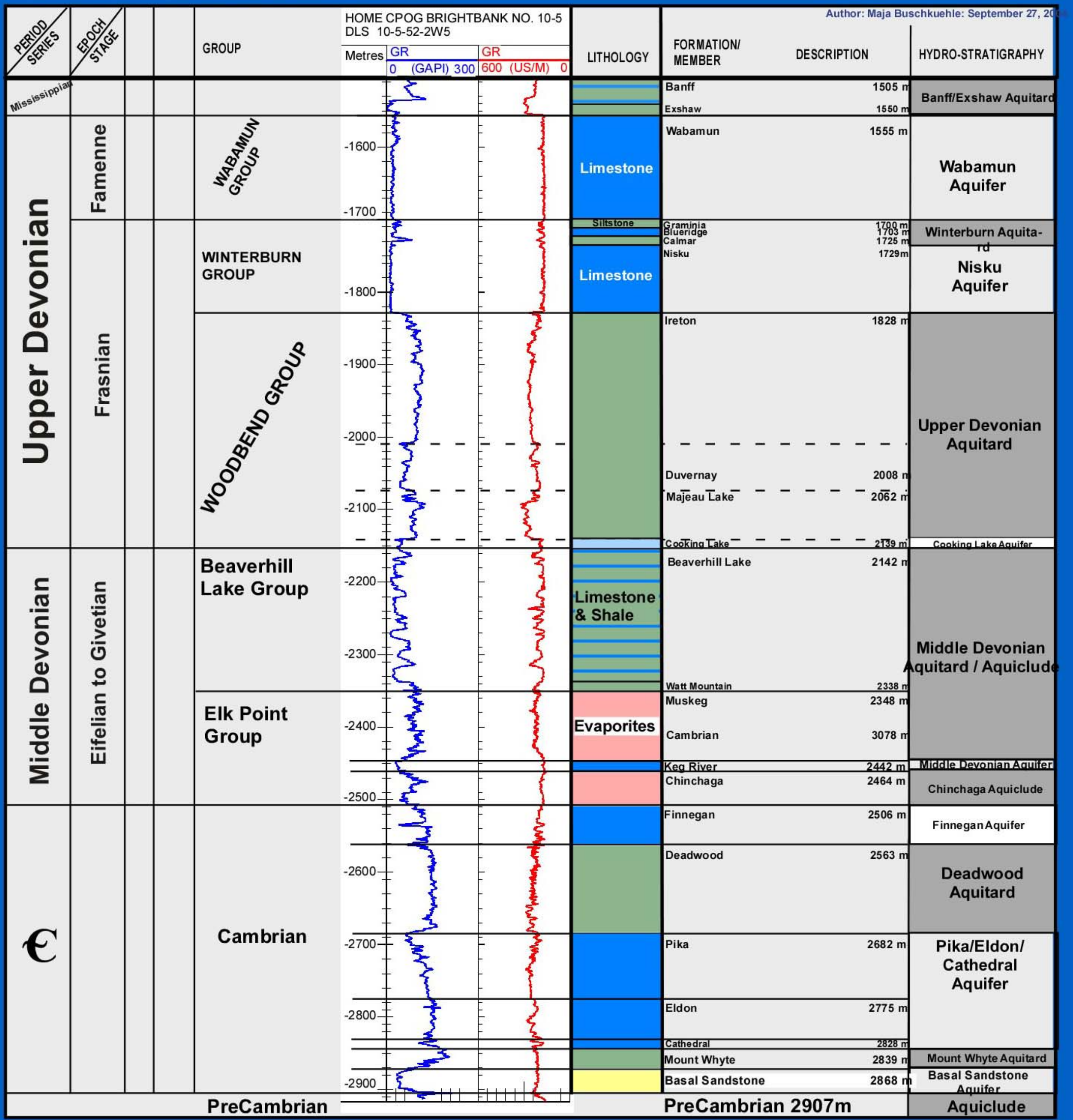


Down-Hole Stratigraphic Model for the Lake Wabamun Area, Alberta,

Pre-Cretaceous Unconformity to Surface

continued…

Location:00/10-05-052-2W5



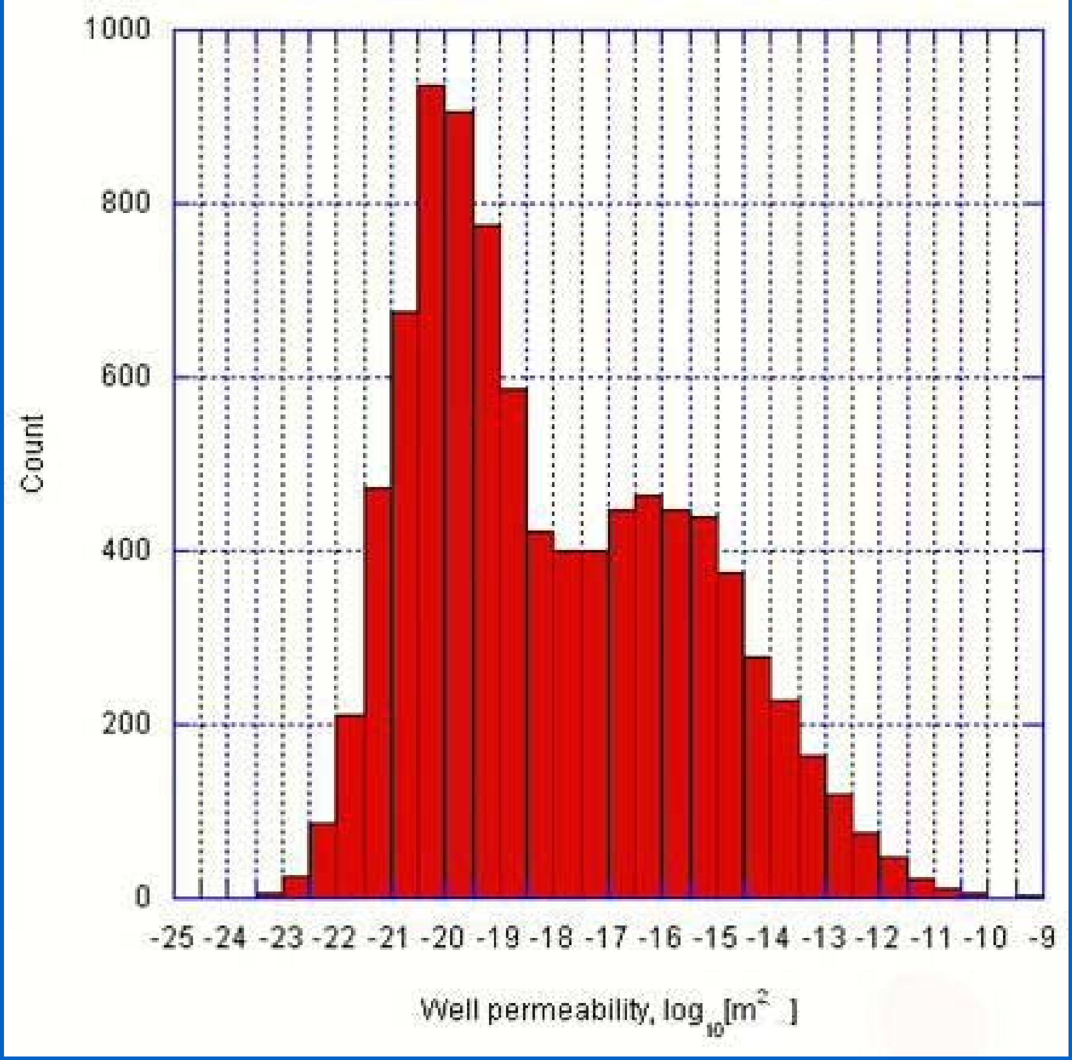
Down-Hole Stratigraphic Model for the Lake Wabamun Area, Alberta,

Basement to Pre-Cretaceous Unconformity

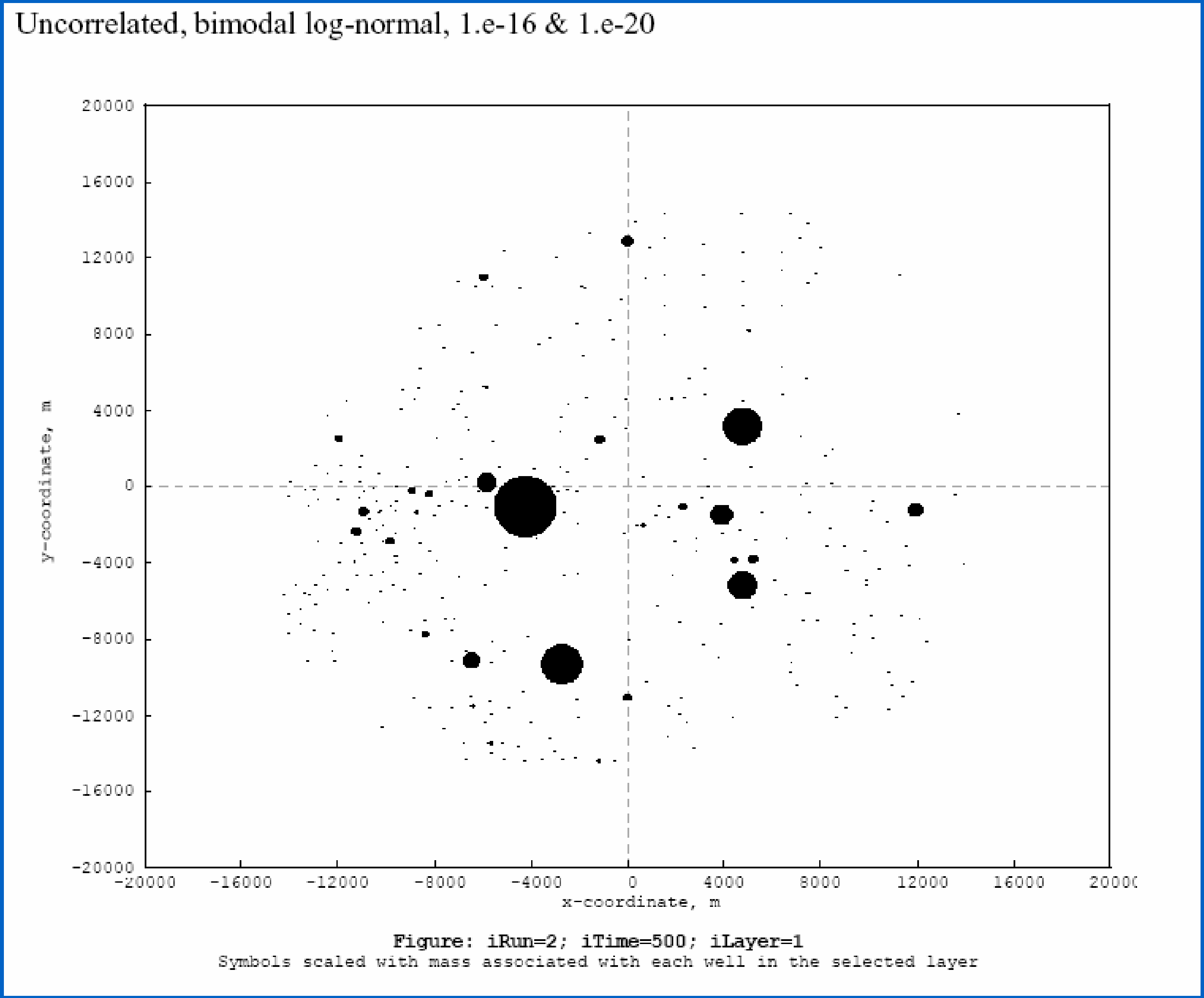
What do we know?

- Injection Location
- Injection Rate
- Fluid Properties
- Formation Properties (k, φ, S_{res}, …)
- Location and Depth of Existing Wells within Plume Radius
- Status of Existing Wells within Plume Radius
- Cemented Intervals along Existing Wells
- Physical State of Well Materials
- Hydraulic Properties of Well Materials ($k_{bulk}(t)$)

Do we need to identify this distribution? If so, how??



Leakage Plumes in Bottom Layer (Run #2)



Leakage Plumes in Bottom Layer (Average)

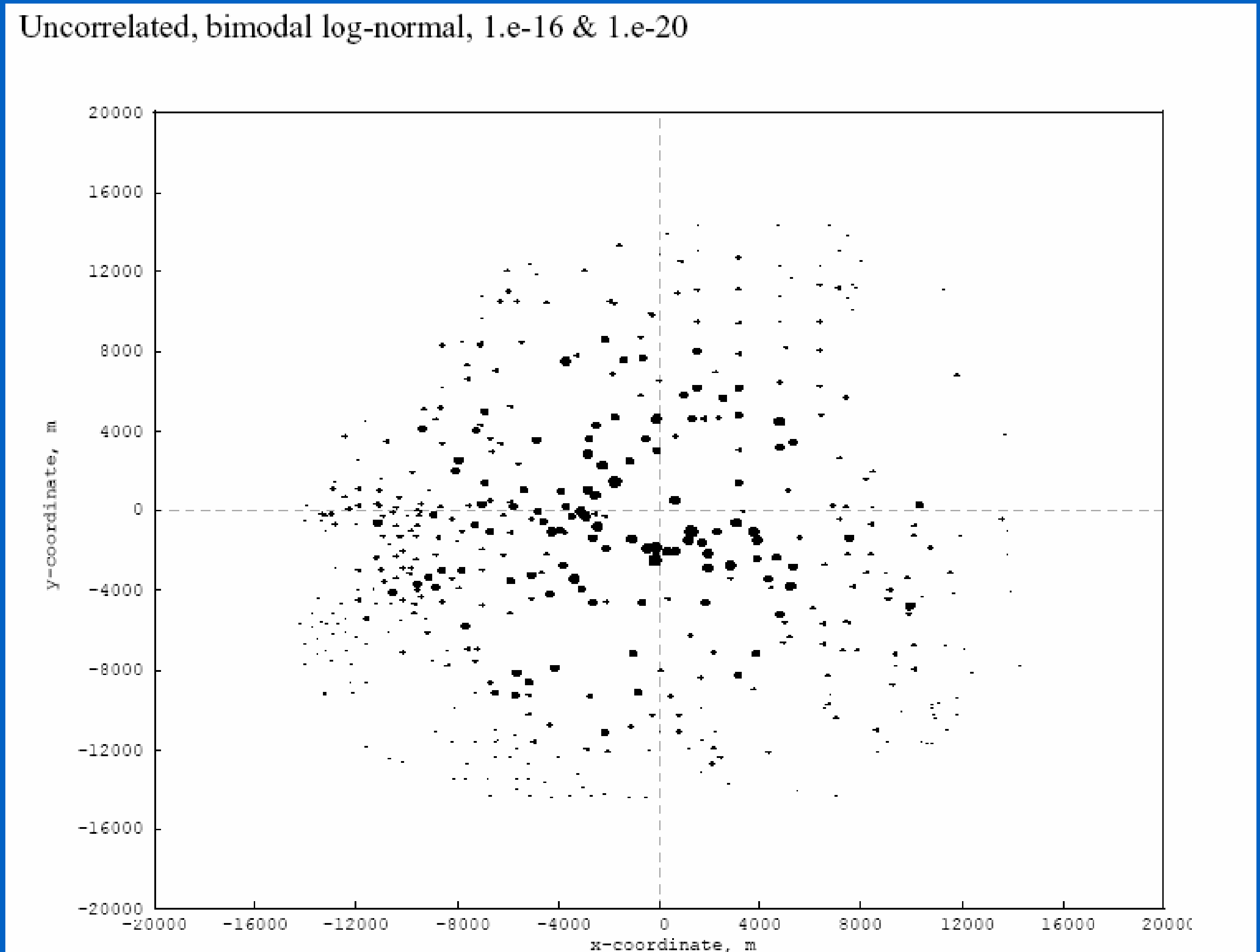
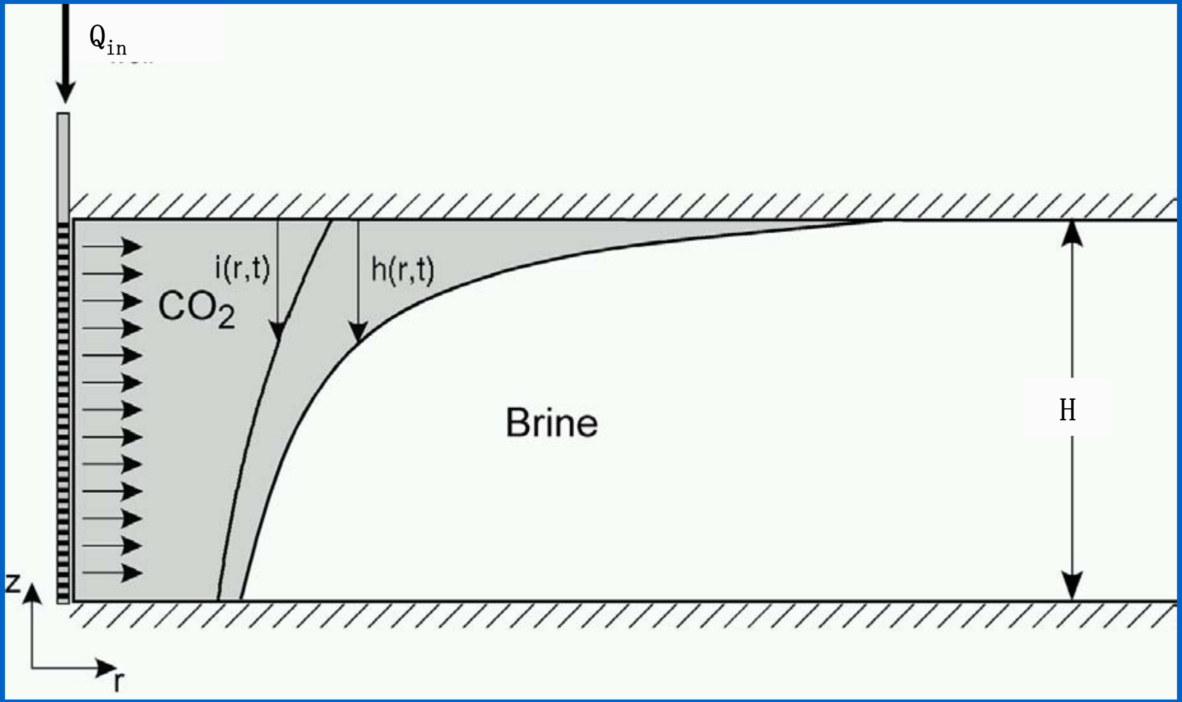


Figure: iRuns=1:600; iTime=500; iLayer=1
Symbols scaled with mass associated with each well in the selected layer

General Similarity Solution (1)



$$-2\pi r\varphi\frac{\partial(H-h)}{\partial t}=\frac{\gamma_1}{1-S_{res}}\frac{\partial Q_w}{\partial r}$$

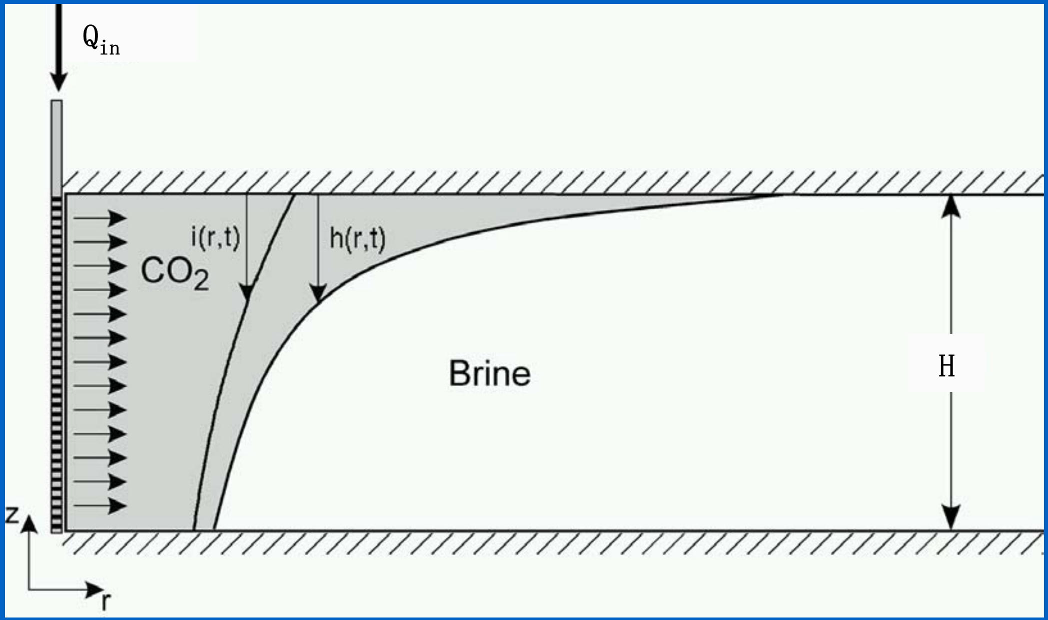
$$-2\pi r\varphi\frac{\partial(h-i)}{\partial t}=\frac{1}{1-S_{res}}\frac{\partial Q_{cw}}{\partial r}+\frac{1-\gamma_2}{1-S_{res}}\frac{\partial Q_c}{\partial r}+\frac{1-\gamma_1}{1-S_{res}}\frac{\partial Q_w}{\partial r}$$

$$-2\pi r\varphi\frac{\partial i}{\partial t}=\frac{\gamma_2}{1-S_{res}}\frac{\partial Q_c}{\partial r}$$

$$\gamma_1=\left[1+\frac{\beta_1 S_{res}}{(1-S_{res})(1-\beta_2)}\right]^{-1}$$

$$\gamma_2=\left[1+\frac{(1-\beta_1)S_{res}}{(1-S_{res})\beta_2}\right]^{-1}$$

General Similarity Solution (2)



$$\Gamma \equiv \frac{2\pi\Delta\rho g k \lambda_w H^2}{Q_{in}}$$

$$\tau \equiv \frac{Q_{in} t}{2\pi H \varphi (1 - S_{res})}$$

$$\lambda_1 \equiv \frac{\lambda_c}{\lambda_w}, \quad \lambda_2 \equiv \frac{\lambda_{cw}}{\lambda_w}, \quad \vartheta \equiv \frac{\rho_{cw} - \rho_c}{\rho_w - \rho_{cw}}$$

$$h' \equiv \frac{h}{H}, \quad i' \equiv \frac{i}{H}$$

$$\gamma_1 = \left[1 + \frac{\beta_1 S_{res}}{(1 - S_{res})(1 - \beta_2)}\right]^{-1}$$

$$\gamma_2 = \left[1 + \frac{(1 - \beta_1) S_{res}}{(1 - S_{res})\beta_2}\right]^{-1}$$

$$\frac{dh'}{d\chi} = \frac{4\Gamma\gamma_1}{\chi}\frac{d}{d\chi}\left((1-h')\chi\frac{dp'}{d\chi}\right)$$

$$-\frac{di'}{d\chi} = \frac{4\gamma_2\Gamma\lambda_1}{\chi}\frac{d}{d\chi}\left(i'\chi\frac{d}{d\chi}(p'+h'+\vartheta i')\right)$$

$$-\frac{d}{d\chi}(h'-i') = \frac{4\Gamma\lambda_2}{\chi}\frac{d}{d\chi}\left((h'-i')\chi\frac{d}{d\chi}(p'+h')\right) + \frac{4(1-\gamma_2)\Gamma\lambda_1}{\chi}\frac{d}{d\chi}\left(i'\chi\frac{d}{d\chi}(p'+h'+\vartheta i')\right) + \frac{4\Gamma(1-\gamma_1)}{\chi}\frac{d}{d\chi}\left((1-h')\chi\frac{dp'}{d\chi}\right)$$

$$\chi \equiv r^2/\tau$$

From: Nordbotten and Celia, *JFM*, (revised version under review) 2005.

CO$_2$ Capture Project

CO$_2$ Storage Wellbore Integrity Field Study: A CCP2 Proposal

Wellbore Integrity Workshop
Princeton, New Jersey
March 28-29, 2006

Scott Imbus, Chevron
Cheryl Stark, BP

CO$_2$ Capture Project

Introduction

- Wellbore integrity widely recognized as the premier CO$_2$ storage containment issue thus a potential show-stopper in depleted oil and gas field venues.
- CO$_2$ well failures have been documented
  - Waste disposal wells (Lehr, 1986)
  - CO$_2$ EOR (Skinner, 2003)
- The EPA UIC program is credited with absence of significant failures of waste disposal wells (Tsang et al., 2001)
- Research to date has focused development / testing of resistant materials
  - CMI
  - Schlumberger
  - LANL
- Successful field study on Kinder-Morgan SACROC by LANL presented at 2005 WBI Workshop

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CO_2 Capture Project

The CCP2 Proposal

Building on past / ongoing studies and information from the 2005 WBI breakout sessions…

CCP2 proposes an integrated CO_2 wellbore integrity field study to assess well condition, document and model degradation processes / rates and simulate well stability into the distant future. The study could comprise the core of a more "comprehensive well integrity program" and the basis for new, cost-effective well designs and remediation and intervention techniques.

Major Tasks Include:
- Well selection & evaluation
- Well sampling, analyses & experiments
- Model construction with history match
- Forward simulation
- Engineering solutions

Ideas and recommendations for the study are requested of the 2006 WBI Workshop participants.

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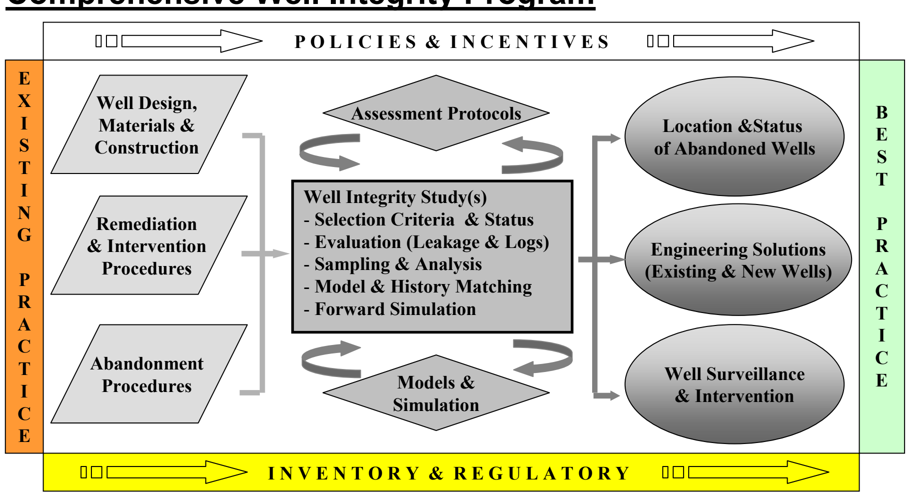
CO_2 Capture Project

Comprehensive Well Integrity Program



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CO_2 Capture Project

Well Selection & Evaluation

Basic Criteria:
- Clastic reservoir and cap rock
- Well CO_2 experience (production vs. injection) and disposition
- Operator access, facilitation and assumption of abandonment costs
- Records (design, materials, injection/ production, integrity testing, workovers)
- Nature of injected / produced fluids (injector vs. producer or mixed; CO_2 humidity & purity, oil & gas)
- Condition of well (altered but not destroyed)
  - Well logging (CBT, USIT/MSIP) and integrity testing
  - Recent solids or fluid samples (swc, cased hole RFT)
  - Pressure and tracer testing

Present candidates include Sheep Mtn. (BP) and other western US “domes”, Rio Pajuca (Petrobras) & Rangely (Chevron)

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CO_2 Capture Project

Well Sampling, Analysis & Experiments

Sample locations based on well log imaging to detect and map altered / non-altered zones

Sampling of altered and non altered zones + pattern
- RFTs & SWCs (fluid only?)*
- Whipstock coring (casing, cement & country rock)
- Other sampling techniques?

Sample Analysis (using screening protocol w/ unaltered samples as baselines)
- Solids (petrography-SEM & mineralogy, petrophysics, Xray-CT, mechanics)
- Fluids
  - Oil & Gas (typing)
  - Water (pH, TDS, alkalinity, ionic, elemental, stable isotopes)

Experiments
- Water-solid (casing, cement & country rock) equilibrium w/ analyses

** Can cement alteration status be inferred from fluid chemistry?*

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CO_2 Capture Project

Modeling & Simulation

Modeling
- Classification and mapping of "defects"
- Qualitative reconstruction of alteration history with production / work over records

Simulation
- Quantitative reconstruction of alteration history
- Variability of alteration under end member injection / production scenarios
- Using analytical, experimental and model data, forward simulate well alteration to X years under end member abandonment and fluid exposure scenarios

CO_2 Capture Project

Engineering Solutions

Based the well integrity study findings, what steps can be taken to avoid well failure? (Workshop Approach)

Design
- Materials and construction that would prevent types of "defects"
- Certification criteria for installation, operation and abandonment

Remediation
- Well evaluation tools and well condition classification
- Novel, inexpensive approaches

Intervention
- In situ and external monitoring tools
- Design considerations for well access
- Novel, inexpensive approaches

Description of an ideal well capable of survival to X years

Reliability standards and risk assessment?

CO_2 Capture Project

Project Cost / Funding, Timing and Governance

Cost
- $2.4MM

Timing (3 years)
- Field / well data, Access & Logistics – Host Operator (3 mo.)
- Well records evaluation & well selection – Princeton CMI (3 mo.)
- Well logging & analysis – Oil field services company (3 mo.)
- Well sampling & assessment – Oil field services company (3 mo.)
- Sample analysis & experiments – University, NL, Vendor (9 mo.)
- Modeling & history match – University, NL (3 mo.)
- Forward simulation – University, NL (3 mo.)
- Synthesis – CCP2 et al. (3 mo.)
- Recommendations – Workshop (3 mo.)
- Reporting (3 mo.)

Governance
- CCP2-operated
- Level of disclosure and IP access TBD
- Advisory Board? Workshops?

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CO_2 Capture Project

Questions for the Group

- Will this project address key CO_2 WBI issues?
- What are the most important well selection, characterization and evaluation criteria?
- Will the models / simulations be realistic (parameters & spatial resolution needed)?
- Might the study outcome lead to excessive regulatory mandates?
- Are well selection and sample acquisition risks manageable?
- Will the study lead to development of new, cost-effective resistant well designs, well remediation approaches and intervention techniques?
- For further information please contact:
  - Scott Imbus, Chevron (scott.imbus@chevron.com) 713 954 6397
  - Cheryl Stark, BP (cheryl.stark@bp.com) 281 366 7604

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