WELL BORE INTEGRITY WORKSHOP

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REPORT ON

WELL BORE INTEGRITY WORKSHOP

Date: 4th to 5th April 2005

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

Organised by IEA Greenhouse Gas R&D Programme and BP

with the support of EPRI

SUMMARY

The integrity of well bores, their long-term ability to retain CO_2, has been identified as a significant potential risk for the long-term security of geological storage facilities. A workshop was held in April 2005 to bring together over 50 experts from both industrial operators and from research organisations. Industrial operations are part of CO_2 enhanced oil recovery (EOR) projects or acid gas waste disposal projects. Current research includes laboratory investigations that attempt to simulate long-term geochemical and mechanical processes that may affect well completion materials – mainly cement; field studies of well completions that have been exposed to CO_2 during industrial projects as described above, and modelling studies, both of local reactions and upscaled simulations of leakage across basins.

Key findings of this workshop include:

- Ensuring well integrity over long timescales has not been attempted before and represents a new challenge to the oil and gas industries.
- It will not be possible to promise a leak-free well, but rather we should emphasise that we can build wells employing state-of-the-art technologies which will reduce risks.
- Portland-based cements will react with CO_2, leading to cement degradation. The main reactions involve carbonation of the major cement components – Portlandite and calcium silicate hydrates which are converted to carbonate minerals such as aragonite, calcite and vaterite.
- Degradation results in a loss of density and strength and an increase in porosity.
- Laboratory experiments of these reactions are able to simulate those observed in wells that have been exposed to CO_2 in EOR injection and production wells. However, the degree of reaction (i.e. the rate of reaction) may not necessarily be comparable between laboratory and field. This may be due to the need to speed up laboratory experiments, often by increasing temperatures, to reproduce longer timescales.
- Although a coupon of portland cement will dissolve within days or weeks of being exposed to CO_2 in the laboratory, in a wellbore setting the limited

permeability of the rock adjacent to the well bore limits mass transfer and corrosion rates. Getting a better understanding of the carbonic ion mass transfer rates under different scenarios is a key area of work.

- One, two and three dimensional models are now being developed to simulate processes observed both in the laboratory and in the field, at the small scale of specific leakage mechanisms within a well and also over the larger scale examining broad leakage on the basin-scale.
- However, we are unable to use these models in a predictive sense due to a lack of detailed knowledge on specific issues, discussed below in the key research needs.
- New cements have been developed and deployed that reduce the amount of alteration caused by acid attack. These cements either reduce the proportion of Portland-based cement in the mix, add inhibitors or use completely new calcium phosphate-based cements that do not contain any reactive portlandite.
- Studies of well completions from CO_2 EOR operations were recognised as offering significant valuable data on real failure processes and consequences. Although these offer the longest "experiments" to date, timescales are still limited to a few decades.
- Initial requirements for a R&D program to investigate such well completions and the types of analyses that could be made on retrieved samples, has been proposed in this meeting.
- Important information could be obtained from areas where it is not possible to obtain cement samples from wells (poor cementing or subsequent degradation could be possible explanations).
- Some of the most desirable potential storage sites are hydrocarbon fields, which have proven traps and the potential for tertiary enhanced recovery. However these same sites are also penetrated by numerous wells which could be susceptible to corrosion. The permanence of CO_2 storage at such sites may therefore not be as high as originally thought.

Key research needs:

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

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

The following next steps were identified:

- Presentations from this workshop and copies of this report are available at www.co2captureandstorage.info/techworkshops/techwkshop.htm.

  A password is required.
- Establishment of a working group on wellbore integrity.
- Suggestions for discussion topics at a future workshop include:
  - Defining well failure
  - Standardising testing procedures
  - Industrial and regulatory evidence for failure frequencies
  - Designing a R&D programme to obtain evidence from existing CO_2 EOR operations.
  - Designing monitoring procedures.

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

Contents

1. INTRODUCTION

This report summarises a workshop on wellbore integrity for the long term geological storage of CO_2 that was jointly organised by the IEA Greenhouse Gas R&D Programme and BP with the support of EPRI. It was chaired by Dr. Charles Christopher of BP America and brought together 50 delegates from research institutes and industry. The workshop was held at the Marriot Woodlands Waterway Hotel and Convention Center, Houston, Texas, USA on 4th to 5th April 2005.

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

Workshop aims and objectives

The integrity of well bore cements to CO_2 rich environments has been raised as an area of some concern with respect to the long term effectiveness of CO_2 storage in geological reservoirs. This workshop aimed to bring together the main research groups that are currently studying the effects of CO_2 on wellbore cements, with industrial groups who have been working with CO_2-rich environments for many years.

The objective of the workshop was to assess the current state of knowledge on the integrity of well bore cements exposed to CO_2 and to address the key future research needs in this area. In so doing, the workshop aimed to develop a picture of how significant, if at all, the effect of CO_2 on well bore cements will be post-storage and if well bores do pose a significant risk of CO_2 leakage in the future.

Workshop Attendees

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

Workshop outcomes

It was expected that the workshop would:

- Lead to the establishment of a working group on well bore integrity that could feed into activities underway on risk assessment,
- Help to develop a list of research needs for assessing well bore integrity in CO_2 rich environments,
- Provide a source of information that can be conveyed to stakeholders.

Workshop Programme

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

- Experience from the CO_2 industry

  Presentations were made by industrial project teams that have been working with the design and maintenance of CO_2 enhanced oil recovery (EOR) injection and production wells or sour gas disposal wells, mainly in the US.

- Current research into CO_2 interactions with wellbore materials

  Presentations by research groups covered a range of research activities that are currently underway to understand and improve the long-term performance of wellbore materials based on field and laboratory-based experience.

- What has been learnt?

  Facilitated breakout sessions allowed delegates to reflect and discuss previous presentations. The following questions were posed to each group to stimulate discussion:

  - Do well bores represent a significant leakage risk from CO_2 storage reservoirs?
  - Do we know how to reduce the risk of CO_2 degradation of well bore cements?
  - Are there standard industry methods to minimise leakage from well bores?
  - Is leakage easy to remediate if it occurs?

- What further work is needed?

Table 1. Wellbore Integrity Workshop Agenda

Monday April 4, 2005	
8:30	Introductions and Workshop Objectives – Charles Christopher
Current Research Into CO2 Interactions With Wellbore Materials	
8:45	Princeton – George Scherer
9:30	Sintef – Ider Akervall
10:15	BREAK
10:45	Schlumberger - Kamel Bennaceur
11:30	Total - Pierre Brossollet
12:15	LUNCH
Modeling Wellbore Integrity	
1:30	Princeton – Mike Celia
2:15	Summarize learnings from the research – What do we know and what does it mean? Groups A and B.
2:45	Report learnings and collate.
3:15	BREAK
Experience With Wellbores In CO2 Environments	
3:45	Sheep Mountain – Larry Nugent, BP
4:15	Halliburton - Lance Brothers
5:00	Wrap-Up for the day

Tuesday April 5, 2005	
8:00	Plan for the day – Charles Christopher
8:15	Oxy Permian – Tommy McKenzie
9:00	Los Alamos National Lab – Bill Carey
9:45	BREAK

10:15	Summarize Field Experience - What do we know and what does it mean? Groups C and D.
10:45	Report learnings and collate.
Designs To Be Stable To CO2.	
11:00	ExxonMobil - Glen Benge
11:45	Lunch
The 1,000 Year Well	
1:00	Based on what we know, what is required to design a well to be stable for 1,000 years? Groups A and B.
2:00	Report learnings and collate.
2:30	Way forward – what research needs to be done?
3:00	Adjourn

2. CURRENT RESEARCH INTO CO_2 INTERACTIONS WITH WELLBORE MATERIALS.

George Scherer, Princeton University: Evaluating Risk of Leakage.

The presentation covered three areas of cement corrosion: development and testing of a model to explore coupled flow-mechanical-geochemical reactions, an experimental study of cement corrosion and comparison with cements obtained from a wellbore following prolonged exposure to CO_2 during industrial operations.

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

The Dynaflow model was used to investigate one-dimensional coupled flow-mechanical-geochemical reactions between cements, CO_2 and brines. It considers a variety of processes that may influence these reactions including CO_2 solubility and its controls (evaporation, salinity, pressure, temperature), transport of CO_2, evaporation, precipitation, compressibility of fluids and matrix, porosity and permeability changes and brine chemistry. Significant differences between CO_2 solubility and brine salinity from this model and previous literature results are attributed to correct treatment of solubility and evaporation processes, which reveals that evaporation reduces CO_2 solubility in the brine. Development of new algorithms allow 3-phase reservoir simulations which can include additional phases such as hydrocarbons, H_2S and CH_4. Future plans include extension to 2D and 3D simulations and inclusion of additional processes such as buoyancy, variable permeabilities and geochemistry to provide a model of leakage through the wellbore annulus.

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

Ider Akervoll, Sintef, Norway: Leaking well modelling and CO_2 interaction with cured well cement.

A flexible reservoir simulation was constructed and used to evaluate the amount of CO_2 dissolved in porewater as a function of the aquifer pressure and temperature, and included a gas-water relative permeability hysteresis model. The effect of the critical gas saturation as a function of imbibition was investigated for a simplified Sleipner case. Dissolution of CO_2 in the aquifer water is the dominant mechanism of CO_2 storage in saline aquifers provided that the vertical communication allows for convective mixing of the CO_2 plume into the aquifer brine. The amount of trapped CO_2 gas due to the gas-water capillary pressure and relative permeability hysteresis decreases when k_v/k_h increases. The percentage of trapped gas is reduced to less than 30 % at a k_v/k_h ratio of 0.1.

Within the CO_2 plume, some convective flow may occur, which is largely dependent on the vertical permeability. Some bypass of convective flow may occur at the plume margins but this will be compensated for by the density effects of increasing CO_2 solution into the water. Low vertical permeabilities result in basal spreading of the CO_2 plume whereas higher vertical permeabilities, result in the plume spreading out under the caprock, as seen at Sleipner.

Currently no satisfactory and robust well model exists to model leakage through abandoned wells, following deterioration of cement plugs, with time and finite permeability and porosity. To get quantitative estimates of the leakage risk it is important to understand the mechanisms and time scales involved in such deterioration processes. It is possible to place production wells controlled at BHP at various places inside the CO_2 plume and study how much leaks out. A simplified approach is to assume that all CO_2 entering the well will reach the surface controlled by the well inflow. Since no information about the well inflow is available the model has no predictive power except for studying the effect of different reservoir parameters for artificially chosen well inflow parameters. Modeling considered three locations for the leaking well: above the injection point (worst case leading to maximum CO_2 leakage), at 1.5 km and 2.1 km horizontally from the injection point. At 1.5 km 5-8% of stored CO_2 in the model was lost, compared to 3-4% at 2.1 km. The leakage rate is sensitive to the ratio of vertical to horizontal permeability, especially when the leaking well is at a greater distance from the injection point.

Cement curing experiments were performed to determine the effects of CO_2 on permeability and porosity. Cements were reacted at high pressures (300 bar, 30,000 kPa) and temperatures (150°C) which are not necessarily representative of CO_2 storage conditions and therefore need caution in extrapolating the results. A none-Portland cement supplied by Haliburton was used as a sealing cement. Following exposure to CO_2 the cement porosity increased from 34 to 39% and permeability increased slightly from 2.3×10^{-20} m^2 to 3.4×10^{-20} m^2. Mineralogical characterisation of the cement indicated that extensive dissolution of spherical particles occurred, especially on the sample surface, and that gehlenite (part of the calcium silicate hydrate matrix) was lost and calcite and aragonite were precipitated.

Potential changes to the mechanical properties of the cements following reaction with CO_2, were examined by but little change was observed. The seismic properties were determined by the Continuous Wave Technique and the compressive strength determined from scratch tests. CO_2 Capillary entry pressures (140 mbar, 14Kpa) were not significantly affected by reaction with CO_2 for 4 weeks.

In conclusion, CO_2 corrosion of Portland cement is thermodynamically favourable and therefore cannot be prevented. The net result is leaching of the cementitious material from the cement matrix, increase of porosity and permeability, and a decrease of compressive strength. Downhole, this translates to a loss of casing protection and zone isolation. By adding pozzolans, the rate of corrosion can be reduced by as much as 50%. The long-term efficacy of the modified Portland cement systems remains to be seen. At best, such systems only postpone the inevitable. More research is needed to develop truly stable, yet economically realistic, cements for this difficult environment.

Veronique Barlet-Gouédard, Schlumberger: Testing of CO_2 resistant material for well integrity under wet carbon dioxide supercritical environment.

Portland cements are not thermodynamically stable in CO_2-rich environments. For wellbores to provide long-term isolation and integrity for thousands of years, new materials need to be developed. This, in turn, requires the development of standard testing equipment in the laboratory and standardised testing procedures that accelerate the assessment of long-term durability. An experimental approach was taken to ascertain whether conventional testing can simulate actual conditions, what needs to be measured to quantify the carbonation process and determine how the carbonation of Portland cement proceeds under supercritical wet CO_2.

Reactions of the components of Portland cement with CO_2 were summarised, resulting largely in the formation of carbonate and bicarbonate, plus silica gel. Conventional testing using a sodium carbonate or bicarbonate solution results in very limited carbonation and doesn't reproduce the acidic conditions of a CO_2-rich reservoir brine. Therefore batch experiments were conducted up to 500 bar (50,000 KPa) and 350°C, where stacked cement plugs were partially submerged in a CO_2-saturated water above which was a supercritical CO_2 atmosphere saturated with water. Following the experiment the fluid pH was determined, the cement plugs were characterised and those samples that straddled the CO_2 water boundary were analysed. X-ray microtomography was used to visualise the aragonite front that precipitated following reaction. Alteration zones up to 6 mm thick from the external surfaces developed after 3 weeks reaction. Carbonation occurs at a rate of 0.2 mm per day for a neat Portland cement. Scanning electron microscopy was used to determine porosity changes with depth which varied from +9% on the surface to a decrease of –2% at the carbonate precipitation front. Portlandite and calcium silicate hydrate cement matrix are consumed to produce carbonates, silica and water. Behind this carbonation front, the neoformed carbonate and silica are dissolved increasing porosity and significantly degrading the cement.

Alternative cements were also tested, including potassium phosphate-based material that contains fly ash and boric acid. Further ongoing work includes testing of a number of commercial cement systems, development and validation of an accelerated ageing test and modelling of the carbonation process in cements.

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

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

This brief presentation provided a background to the discussions of new cement applications for ensuring well integrity for thousands of years in a CO_2 storage facility. Cements have been used for thousands of years, though Portland cement was developed in the 1830s by Joseph Aspden. In the US, cements are classified into Types I-IV depending on grade and amount of water, which influence density and permeability. In the API, cements are categorised as A to D. Type C, for example, is sulphate resistant and Class A cements are primarily used in construction. Type G and H cements, mentioned in some of the previous talks, are used in the oil industry in the Gulf Coast. Type G is a finer version of Type H.

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

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

3. MODELLING WELLBORE INTEGRITY.

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

In Texas, there are 1-1.5 million wells and in Alberta there are 350,000 wells with 195,000 wells penetrating the Viking Formation alone and 15,000 new wells being added each year. In oil production an injection well may be surrounded by 100s of wells, in gas production there may be 50-100 wells and a few tens of wells in backyard wells. When trying to represent potential leakage we need to consider the problem of upscaling from leakage pathways typically on a millimetre scale to a reservoir or hydrocarbon field or basin. Several types of leakage pathway can be considered depending on the location of the failure point within the well. The consequent high uncertainty in parameters requires efficient computation. The components of the semi-analytical model include injection phase evolution, leakage dynamics, post-injection redistribution and upconing around leaking wells which can lead to flow of fresh CO_2 up a well.

Permeabilities and relative permeabilities were assumed. Fluxes were calculated with flow out radially into intervening aquifers. Leakage in each aquifer varies by many orders of magnitude. In two-phase flow from an injection well to a leaky well, initially only brine leakage is observed. The CO_2 plume can prevent brine upflow when it is thick enough.

A real case history of a field in the Alberta Basin was modelled with an extreme simulation and distribution of leaking wells. The distribution of CO_2 in the overlying aquifers is controlled by the relative permeabilities. The top aquifer accumulated 20% of the volume injected.

A plea was made for the oil industry to share their experiences of leaky wells with the research community.

4. EXPERIENCE WITH WELLBORES IN CO_2 ENVIRONMENTS

Larry Nugent, BP – Sheep Mountain

The Sheep Mountain Unit (SMU), Colorado produces CO_2 from a naturally occurring CO_2 field, which is transported 408 miles by pipeline for use in EOR floods in West Texas. Recovery from the Dakota (~3400' TVD, 1036m) and Entrada (3800', 1158m) sandstones is 1.2 TCF. The produced gas is 96% CO_2 which is currently produced at 54 MMCFPD, across 5 drill sites with 29 producing wells.

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

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

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

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

The effects of CO_2 on cements is a well-documented phenomena, involving the carbonation of Calcium Silicate Hydrate (CSH) cement matrix and portlandite. The solution therefore is to develop non-portland based cements, such as the calcium phosphate cement (trade name ThermaLock) which contains aluminium hydrates, calcium phosphate hydrates and mica-like aluminosilicates. In comparative tests with Portland cements, weight loss was 3% compared to up to 50% with Portland cement, depending on the additives used. This cement has been used in geothermal wells with high CO_2, CO_2 injection wells and sour-gas disposal wells.

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

The SACROC reservoir is a Pennsylvanian reef, with 3 billion barrels of original oil in place. 1800 wells are located within the 81 square miles, 600 of which are operational. The production zone occurs at 7000' depth with a field temperature of 50°C. initial pressure was 3200 psi (now 2600 psi). CO_2 flooding initiated in 1972 (second CO_2 flood in the world), now being supplied from McElmo Dome, of which 62% is left within the reservoir. Drilling and production from above and below the reservoir have been CO_2 free. Sidetrack cores have been taken from both injection and production wells to determine the long-term effects of CO_2 on casing, cement and shales. Samples have been successfully obtained that allow a profile from the reservoir through the cements and into the well casing, which has been exposed to CO_2 as a producer and injector for 17 years. A similar style of alteration was observed to that reproduced in laboratory-based experiments, including the development of orange-stained cement (due to decomposition of AFm phases and precipitation of ferric hydroxide, rather than redox changes) and extensive carbonation, in the form of calcite, aragonite and vaterite. Stable isotope studies were able to differentiate between carbonates in the cement, and altered cements.

These results indicate that EOR sites have tremendous potential for evaluating the feasibility of CO_2 storage. Recovery of core at SACROC and from the Tensleep Formation demonstrate that cement can retain integrity for decades. CO_2 does attack cement but there are stages of carbonation that precede and help prevent mechanical failure. Experimental studies of the carbonation process are necessary to interpret the observed textures and numerical modeling is helpful in understanding processes and time-scales implied by the observed mineralogy and texture. We should pay just as much attention to the cement/casing that is absent as the core that can be recovered.

One dimensional modeling, using Flowtrans, indicated an increase in porosity in the orange zone from 16% in the cement to 30%, with a dense calcite-rich zone, plus chalcedony and dawsonite (a sodium aluminium carbonate often predicted to form in geochemical models) which probably equates to an amorphous alumina in the altered zone. The lengthscales generated within the models are comparable to those observed in the samples, though the rates of Portlandite reaction were increased to make it react quicker.

5. DESIGNS TO BE STABLE TO CO_2.

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

A case study was presented that provides examples of state of the art design in well completions for acid gas (65% H_2S, 35% CO_2) injection over a 50-year period in the Labarge area, Wyoming. The wells were 18000' deep, through a potential mobile salt formation, at a temperature of 300°F (150°C). Corrosion resistant alloys were used throughout. The resistance to chemical degradation of a Portland cement were increased by adding a latex diluent of a specific particle size and adding a non-standard, high alumina cement to reduce the amount of Portland cement. The design plan included a quality control system for the complicated blending, quality checks by multiple laboratories and a plan for future well interventions. A Portland-based cement was chosen for logistical and availability advantages. Complex casing installations were also explained. Following completion, wells were monitored for ultrasonic cement analyser for integrity.

Tor Harald Hanssen, Statoil – Permanent CO_2 Storage

The Sleipner operation was reviewed and plans for the Snøhvit field in the Barents Sea introduced. At Snøhvit, the CO_2 injection well was drilled in January 2005, 150 km offshore in an environmentally sensitive area where no discharges are allowed. The Tubåen Formation, the target storage reservoir, is a sandstone saline aquifer below the gas field, which will store the CO_2 from the produced gas as well as from an onshore power plant. A 13% Cr steel is being used for all tubing.

6. SUMMARY OF BREAKOUT DISCUSSIONS.

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

What do we know?

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

Important information could be obtained from areas where it was not possible to obtain cement samples from wells (poor cementing or subsequent degradation could be possible explanations) and this should be investigated. CO_2 will dissolve cement in the lab, and is thermally controlled, producing reaction zones which can have different properties and that can slow reaction. The degree of curing does not influence degree of reaction. Two-phase flow is more destructive than single phase (as acidity replenished). Some compositions are resistant to reaction as a result of their chemistry and porous media around cement can slow reaction, though cement is more at risk in sandstone than limestone. There are no industry standard tests for corrosion. Good cementing practices are needed and there are particular challenges for ensuring good cement bonding? in shales.

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

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

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

Remediation can be difficult.

Identified questions included:

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

What does this mean?

It was recognised that current practice is not adequate to ensure long-term wellbore integrity, with no experience for long-term i.e. on the timescale of decades.

Standard testing methods are needed and it was suggested that this could be the subject of a follow-up workshop.

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

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

What should be done?

Education of risks and rewards to both industry and regulators is required with statistical information on leakage being provided from industry on both operational and abandoned wells in current oil and gas production, though some is available from CO_2 fields and studies in CCP. There is a clear need to identify the locations and integrity of all wells that could potentially act as pathways for CO_2 leakage in a storage area. Though less likely to be an issue offshore, in onshore basins such as those in the US, this may not be a trivial issue. The number of wells influences the risk of a leak though this does not mean a high number of wells is automatically a higher risk. It could be expected that a higher number of failures may occur early on in the lifetime of a project, which may reduce over time. However, we do not know what will happen over the long term (100+ years).

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

Accelerated testing methods of degradation on several scales, including permeability evolution and leakage at interfaces between wellbore completion materials, are required to assess long-term well performance without making the experimental conditions unrealistic. Useful information on in-situ CO_2/cement reactions could be obtained from samples in wells that have seen CO_2. Redox issues should be considered. Cement Samples from existing wells are needed to improve the dataset from which observations can be made and this may be best achieved during well workovers. However it was recognised that the risks to operators of sampling from operational wells should be minimised.

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

New potential mechanical liners/barriers should be considered.

To define risks the following need to be established: frequency of failure, mechanisms of failure, the consequences of failure as well as a definition of failure. Delegates, aware that industry has a different set of definitions compared to researchers, suggested the following could be used a criteria to measure well performance:

- No loss to atmosphere
- Acceptable HSE risks
- Deviation from stated objectives – failure to keep injection within target reservoir.
- Define leakage pathways near wellbore as a result of emplacing well. Identify failure modes.
- Migration into potable water zone.
- CO_2 reaches above the protective casing.
- Careful consideration of terms like leak and failure are needed.
- Potential for mobilisation of other phases (hydrocarbons, Rn etc.)
- Potential for local shallow accumulation with sudden release thereafter.

An experimental approach to determine field-validated processes was discussed. This was based on a well in an existing CO_2 flood or CO_2 field, or possibly in an engineered leak. Suggested techniques are listed below:

Logging techniques	
geochemical	
temperatures	tracers
Cement bond logs	Fluid sampling
Well selection criteria	
Low risk of failure of experiment to operator (choose a well that is going to be abandoned anyway).	
CO2 in ground a long time	Well with some migration
Well history/boundary conditions needed	
Pressures	Rates of injection
Temperatures	Original cement composition
Initial and current logs	Age
Geology	Completion
Crosswell seismic for CO2 distribution	Fluid composition
Permeabilities	Acid jobs
Adjacent activity	
Experimental procedure would be	
1. log USIT/MSIP	
2. Cased hole RFT (Residual formation t) for fluid samples	
3. pressure tracer tests	

4. Drill oriented sidewall samples in caprock and cements	
5. Whipstock samples	
6. plug and abandon	
Fluid samples:	
Full chemical analysis including pH	
Difference between invaded & non-invaded zones	Biological sampling
Rock samples:	
Permeability, porosity	Saturations
Porewaters chemical analysis	Petrographic analysis
Expose to reservoir brine	NDT-XRD/ tomography

7. FINAL DISCUSSIONS ON THE "1000-YEAR WELL"

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

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

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

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

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

An early requirement is to define the failure criteria. Suggestions include loss of CO_2 to the atmosphere or to a potable water supply or CO_2 leakage to an overlying reservoir.

8. KEY OUTCOMES

- Ensuring well integrity over long timescales has not been attempted before and represents a new challenge to the oil and gas industries.
- It will not be possible to promise a leak-free well, but rather we should emphasise that we can build wells employing state-of-the-art technologies which will reduce risks.
- Portland-based cements will react with CO_2, leading to cement degradation. The main reactions involve carbonation of the major cement components – Portlandite and calcium silicate hydrates which are converted to carbonate minerals such as aragonite, calcite and vaterite.
- Degradation results in a loss of density and strength and an increase in porosity.
- Laboratory experiments of these reactions are able to simulate those observed in wells that have been exposed to CO_2 in EOR injection and production wells. However, the degree of reaction (i.e. the rate of reaction) may not necessarily be comparable between laboratory and field. This may be due to the need to speed up laboratory experiments, often by increasing temperatures, to reproduce longer timescales.
- One, two and three dimensional models are now being developed to simulate processes observed both in the laboratory and in the field, at the small-scale of specific leakage mechanisms within a well and also over the larger scale examining broad leakage on the basin-scale.
- However, we are unable to use these models in a predictive sense due to a lack of detailed knowledge on specific issues, discussed below in the key research needs.
- New cements have been developed and deployed that reduce the amount of alteration caused by acid attack. These cements either reduce the proportion of Portland-based cement in the mix, add inhibitors or use completely new calcium phosphate-based cements that do not contain any reactive portlandite.

- Studies of well completions from CO_2 EOR operations were recognised as offering significant valuable data on real failure processes and consequences. Although these offer the longest "experiments" to date, timescales are still limited to a few decades.
- Important information could be obtained from areas where it is not possible to obtain cement samples from wells (poor cementing or subsequent degradation could be possible explanations).

9. FUTURE RESEARCH NEEDS

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

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

10. NEXT STEPS

The IEAGHG will place copies of the presentations and this meeting report on www.captureandstorage.info. The presentations and report of the workshop will be in a delegate's only area of the site but a public domain summary report will be produced and placed in the public section of the site.

A follow-up meeting will be held when sufficient progress merits further discussion. Possible topics for discussion could include, *inter alia*:

- Defining well failure.
- Standardising testing procedures.
- Industrial and regulatory evidence for failure frequencies.
- Designing a R&D programme to obtain evidence from existing CO_2 EOR operations.
- Designing monitoring procedures.

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Well Bore Integrity Workshop

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

Organised by IEA Greenhouse Gas R&D Programme and BP

with the support of EPRI

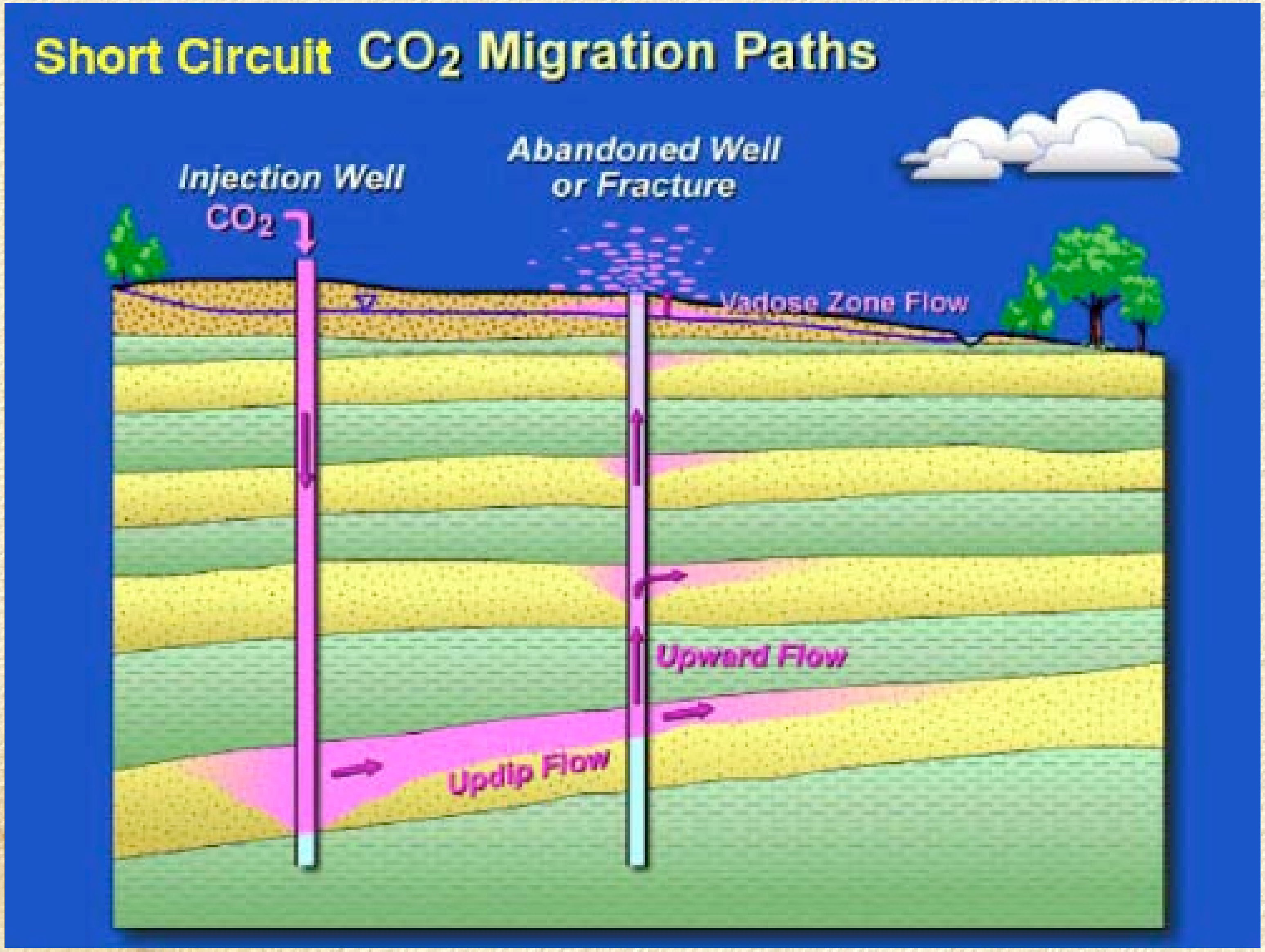
4-5 April 2005

Geological Storage of CO_2

Evaluating the Risk of Leakage

Injection & Leakage

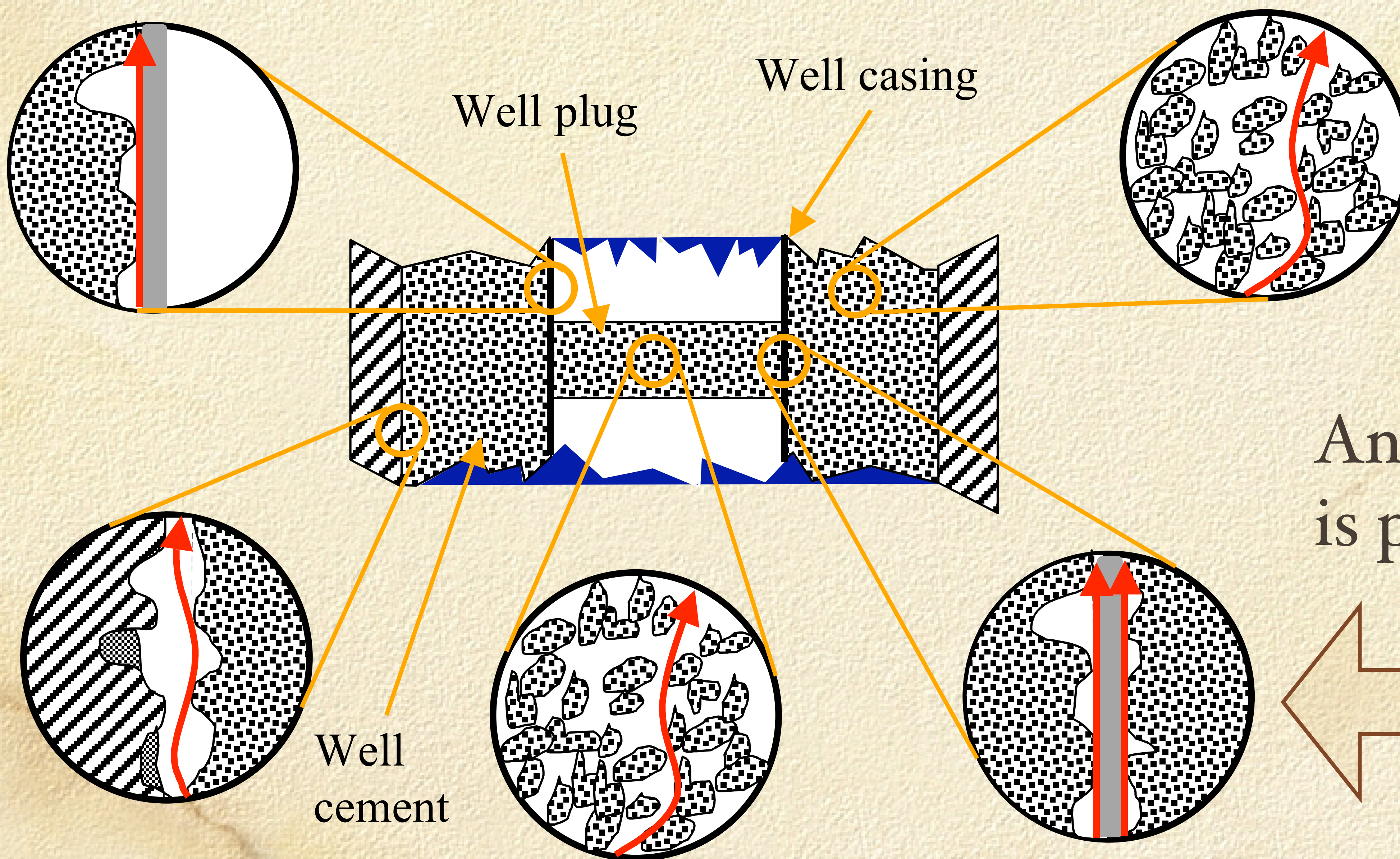
- Reservoir model must predict composition of brine that comes into contact with cement



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

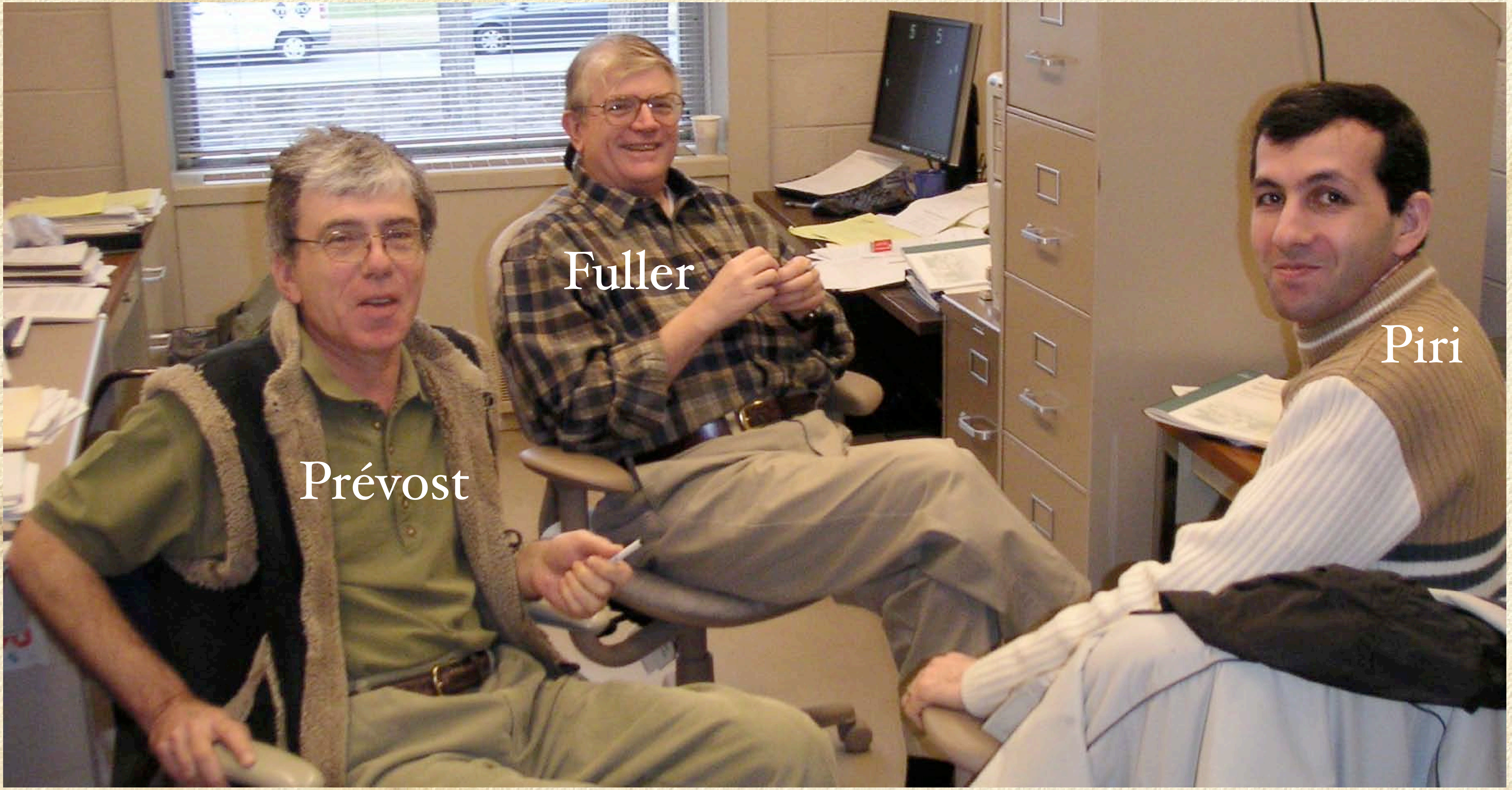


Annular gap is primary focus

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?*

Simulation Crew



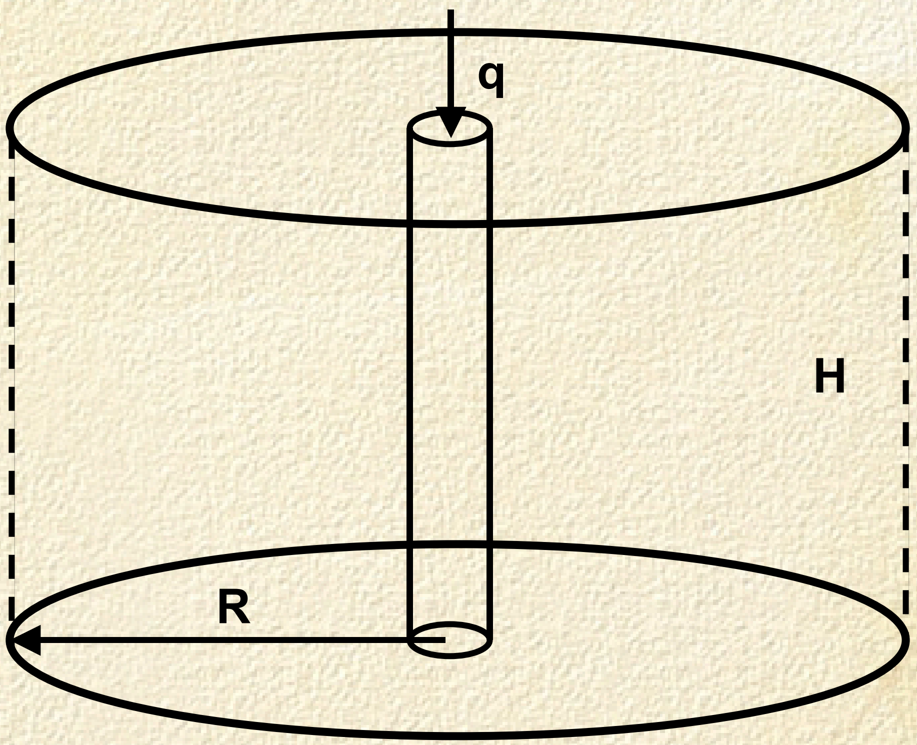
Reservoir Model : *Dynaflow*

Jean Prévost, Dick Fuller, Mohammad Piri

- Dependence of solubility of CO_2 in the brine on
  - Evaporation, Changing salinity, *P*, *T*
- Transport of salt & CO_2
- Evaporation of water behind the front, close to the injection well
- Precipitation of salt due to evaporation
- Compressibility of fluids & matrix
- Porosity change by salt precipitation & matrix compressibility
- Permeability change due to change in porosity
- Acidity & solute content of brine

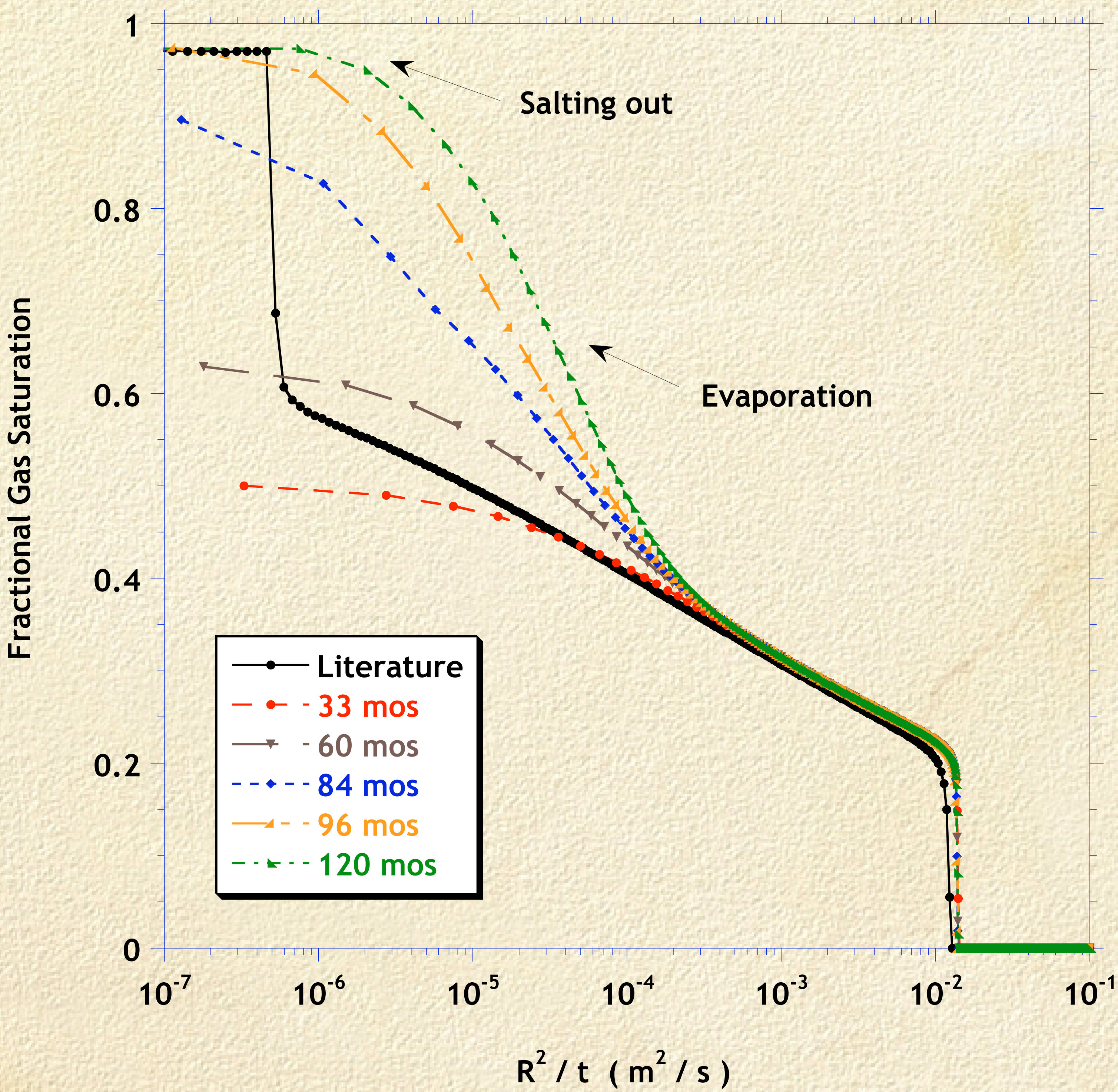
Simulation Parameters

- T = 45 °C , P = 12 MPa
  K_{abs} = 100 mD
  φ = 0.12
  [NaCl] = 15 wt%
  q = 100 kg/s
  R = 20 km
  H = 100 m
  S_{gr} = 0.05 , S_{lr} = 0.30
  Matrix compressibility = 0.45 GPa^{-1}
  Incompressible fluids



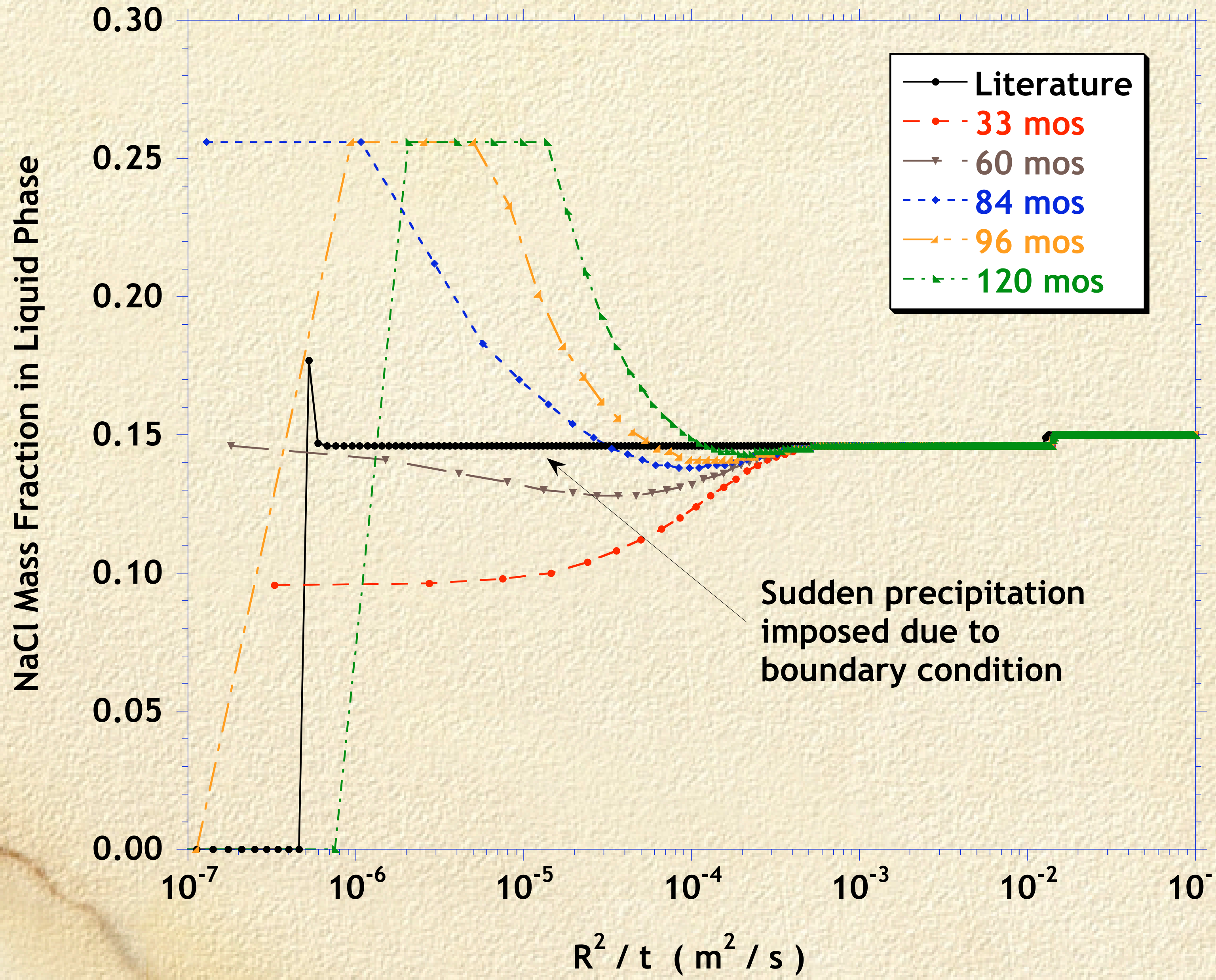
Comparison to Literature

Significant differences owing to proper treatment of solubility & evaporation



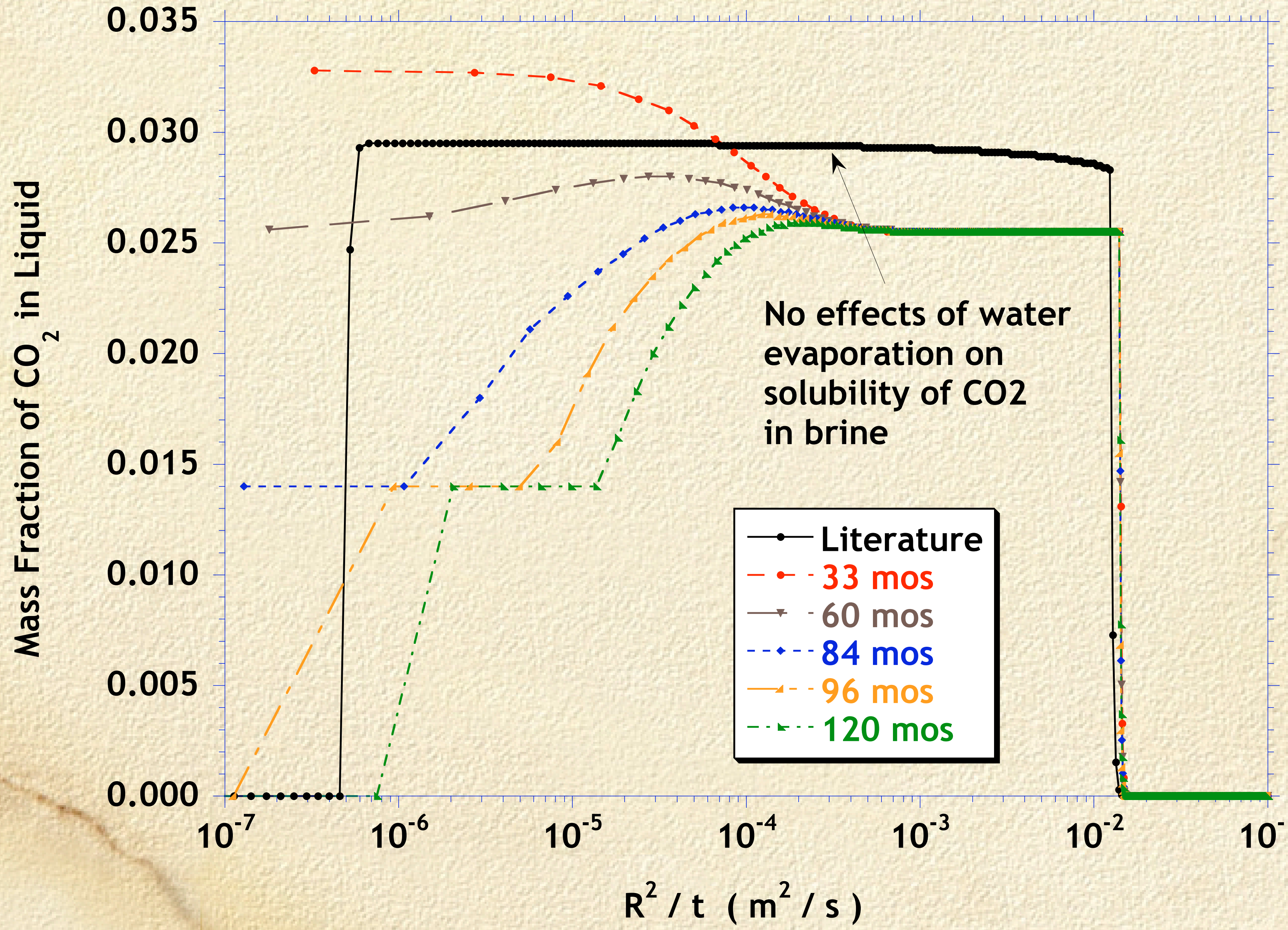
Comparison to Literature

- Correct effect of evaporation on salinity



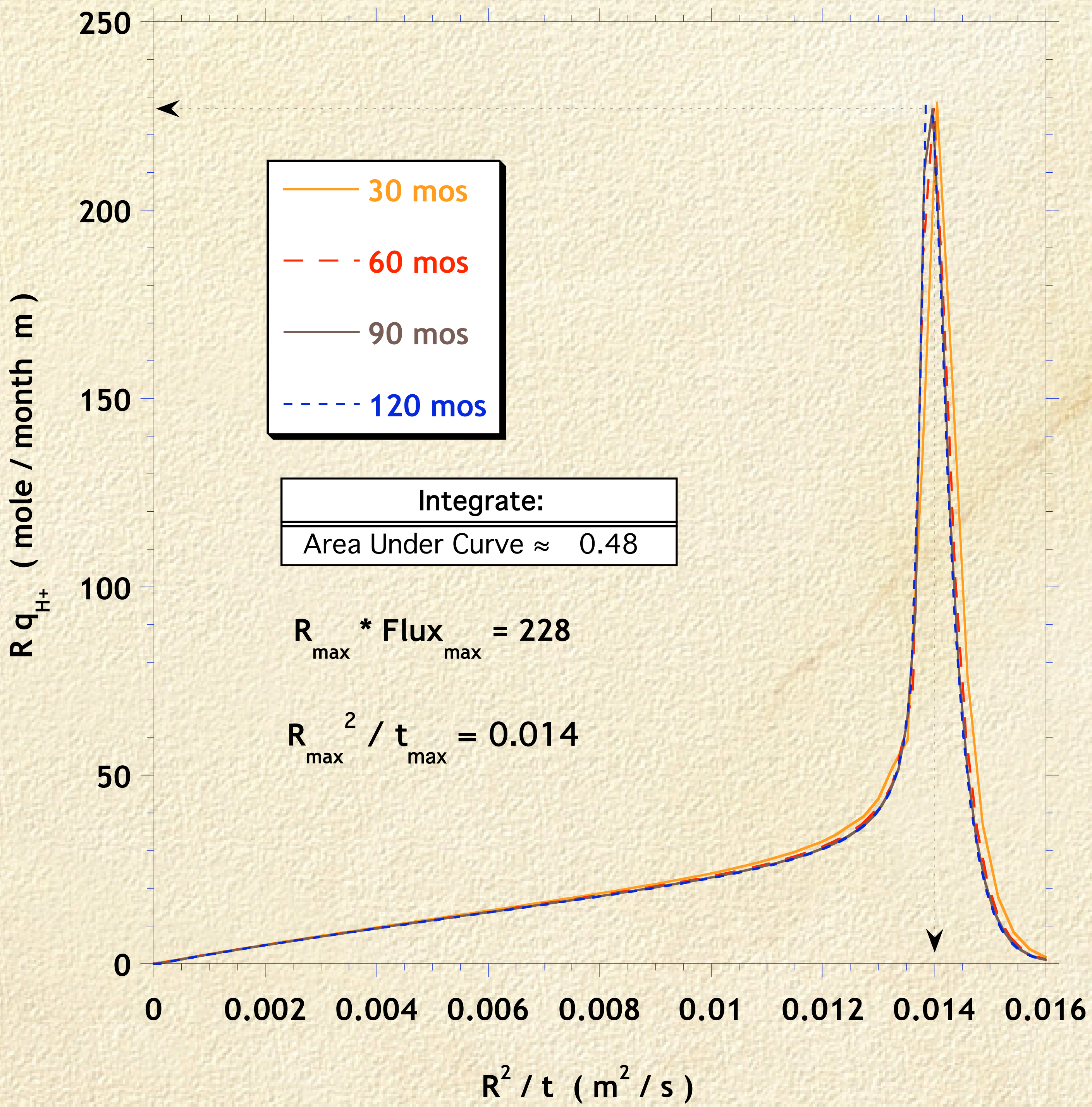
Comparison to Literature

- Effect of evaporation on CO_2 content of brine



Flux of Acid

- Moles of acid passing a given point
- All curves scale as expected
- Permits analysis of amount of cement removed



Conclusions

- CO_2 storage is affected by evaporation
  - "salting out" effect = reduction in CO_2 solubility as salt concentration rises
- New "flash" algorithm works with 3-phase reservoir simulation (vapor + brine + solid salt)
  - extendable to include H_2S, CH_4, etc.
- Injection simulated by controlling flux
- Numerical procedures yield exceptional stability

Future Plans

- 2D and 3D Simulations
- Effects on CO_2 storage of
  - buoyancy
  - heterogeneous permeability field
  - hysteresis in relative permeability & capillary pressure
  - geochemistry (dissolution and precipitation)
- Extend flash to include
  - CH_4 and H_2S injection (→ second liquid)
  - Hydrocarbons in formation (→ 3-phase flow)
- Physically-based 3-phase relative permeabilities
- Model of leakage through annulus

Corrosion of Cement

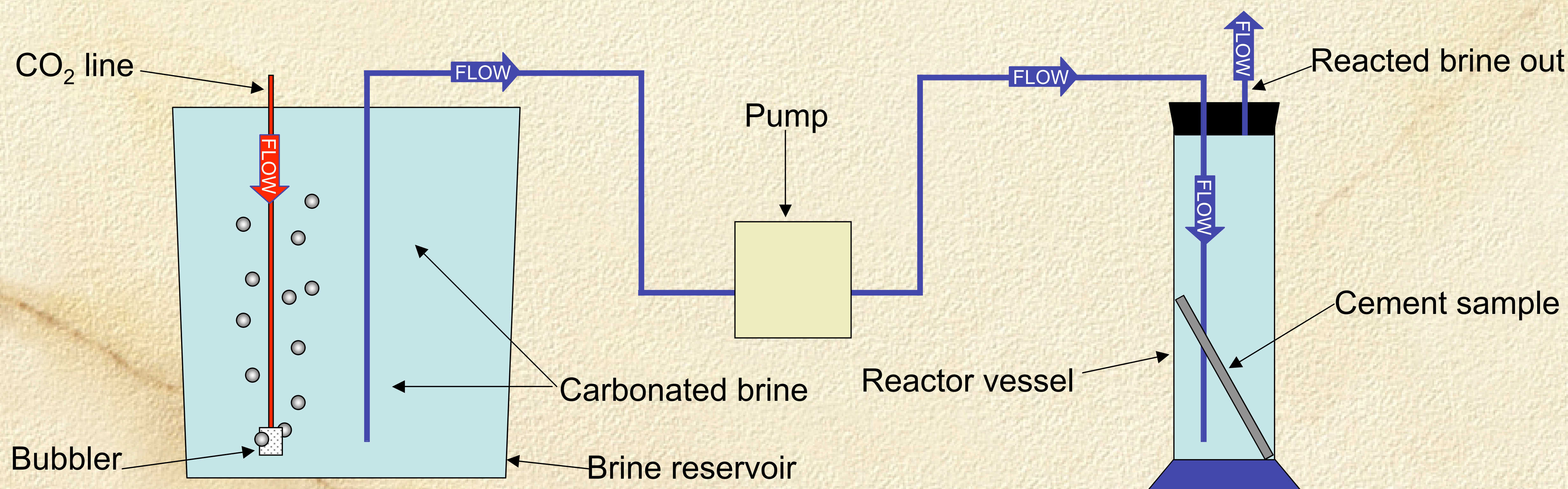
(*Andrew Duguid, Mileva Radonjic, GWS*)

- 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

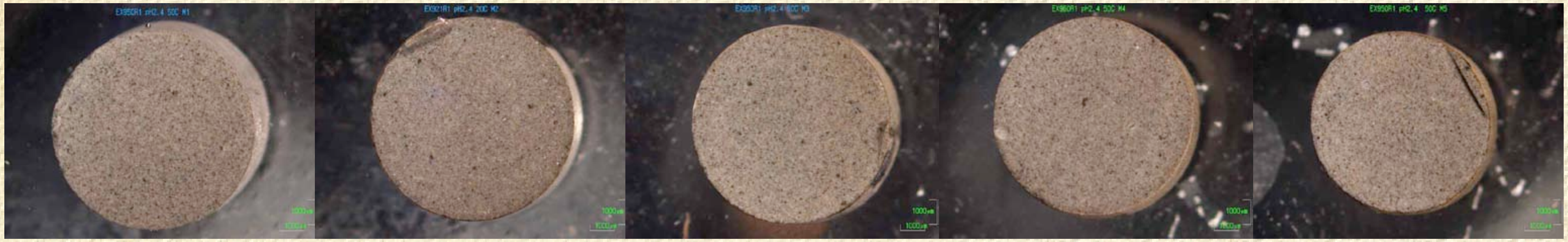
(Continuous fresh acid)

- 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)



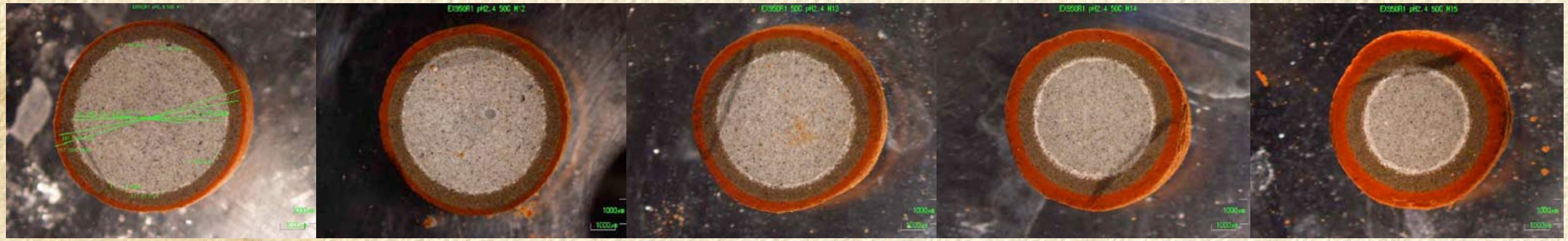
Flow-Through Experiment
(Continuous fresh acid)

- Sandstone formation: pH 3 , 50°C



0 hours 6 hours 24 hours 30 hours 2 days

3 days 4 days 6 days 7 days 8 days

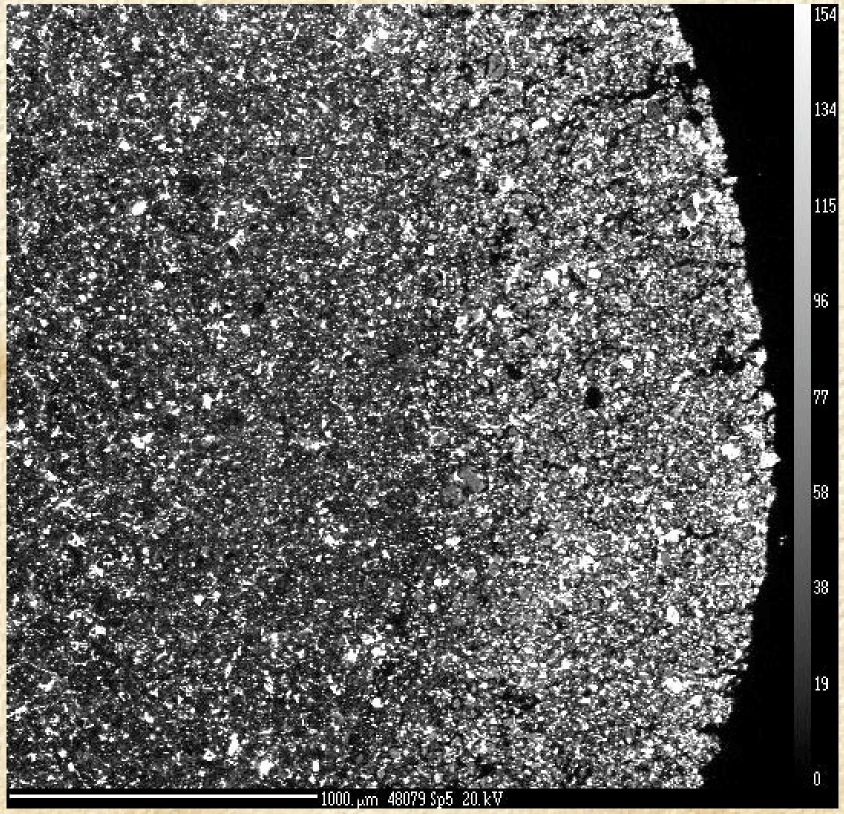


10 days 12 days 14 days 17 days 20 days

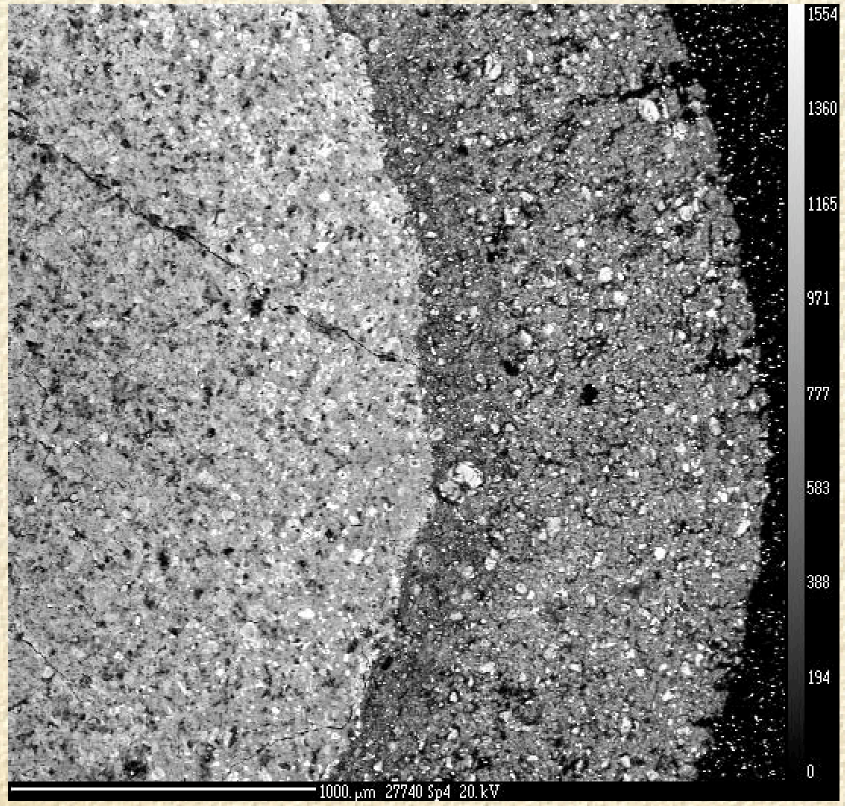
Composition Maps

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

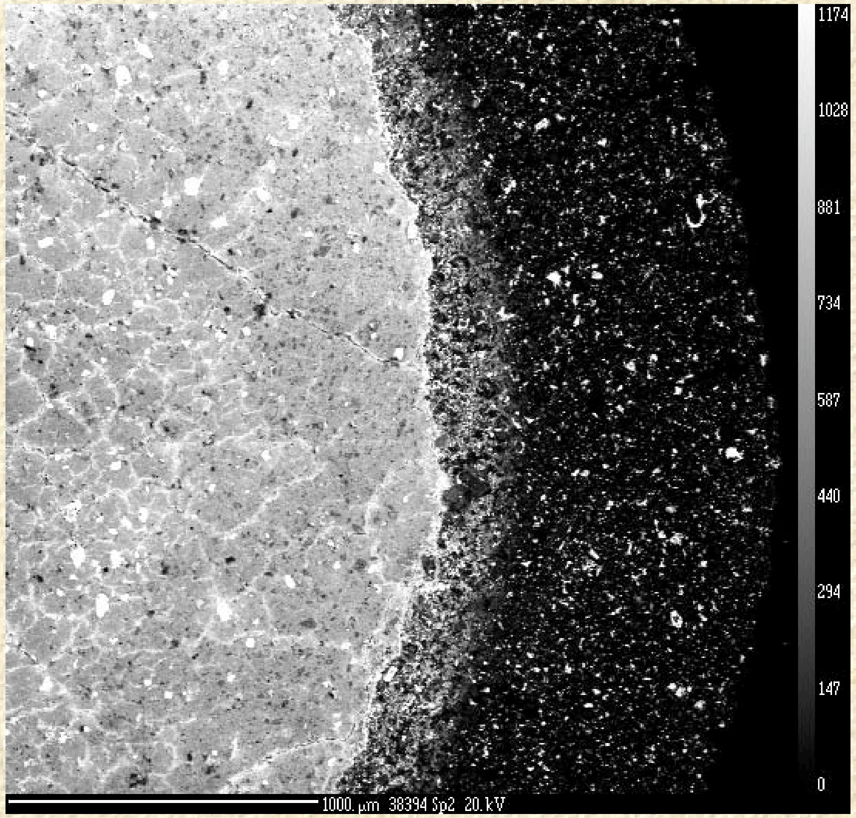
Iron



Silicon

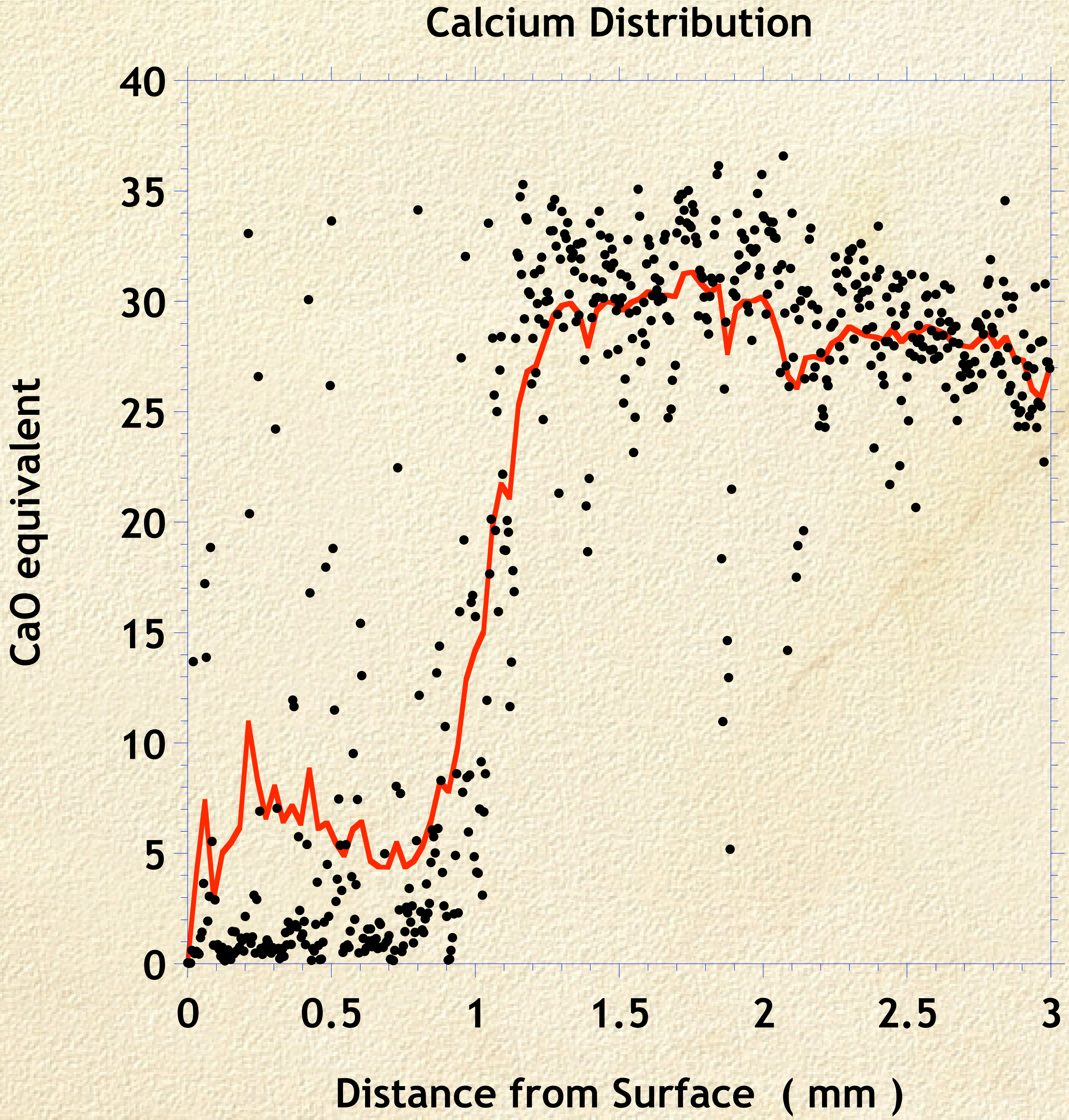


Calcium



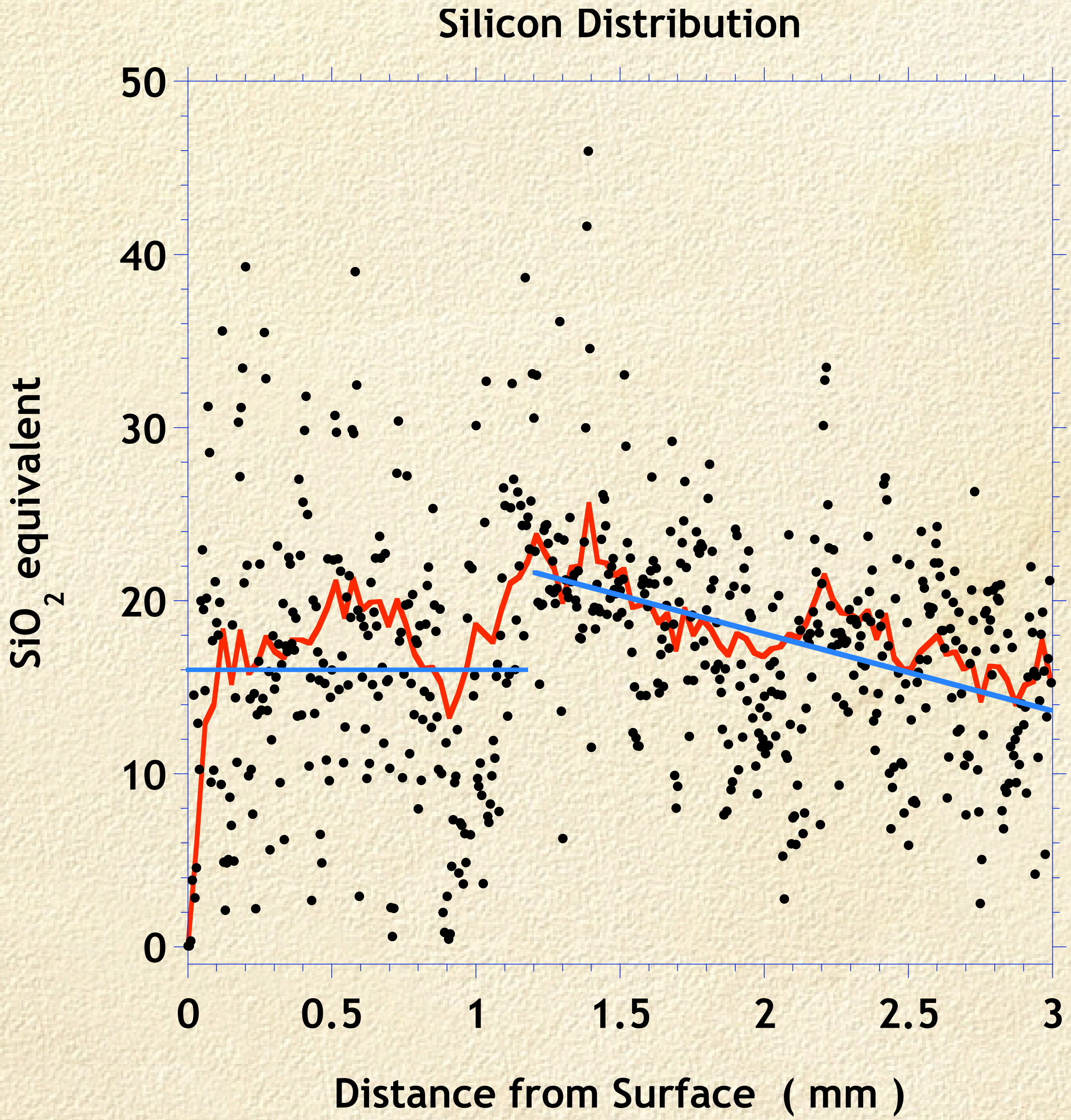
Quantitative Profiles

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



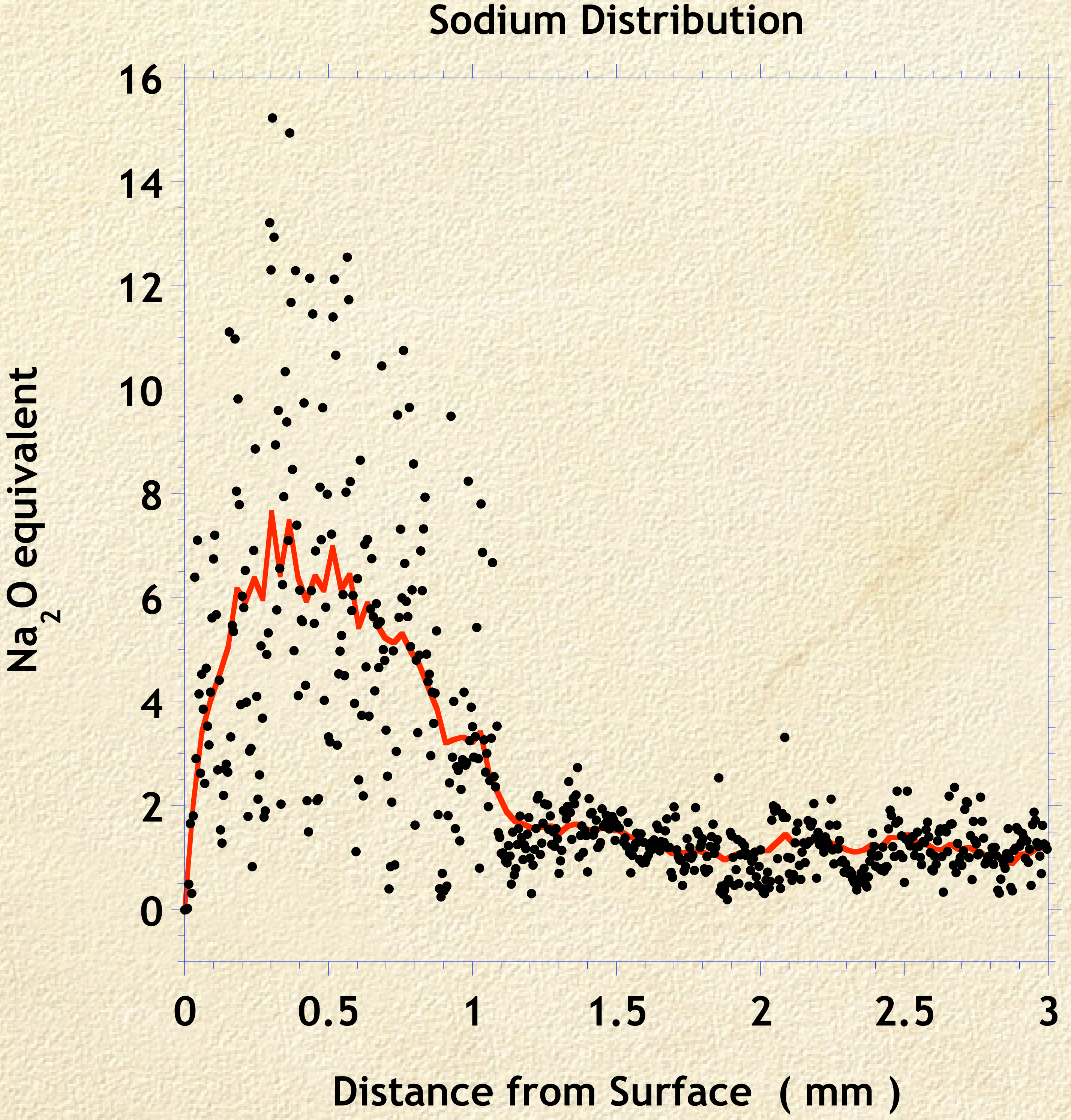
Quantitative Profiles

- Silica content remains uniform
- Outer layer is primarily silica gel



Quantitative Profiles

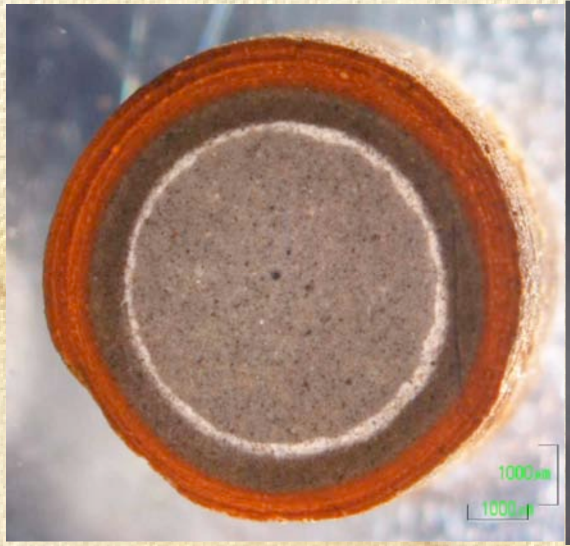
- Sodium from brine invades porous outer layer



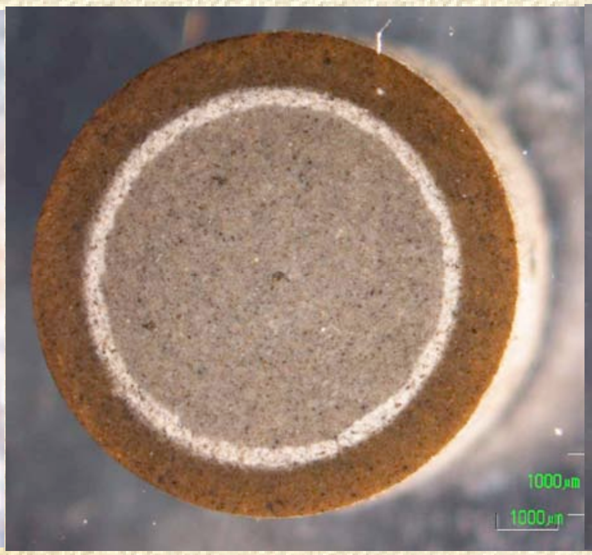
Flow-Through Experiment
(Continuous fresh acid)

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

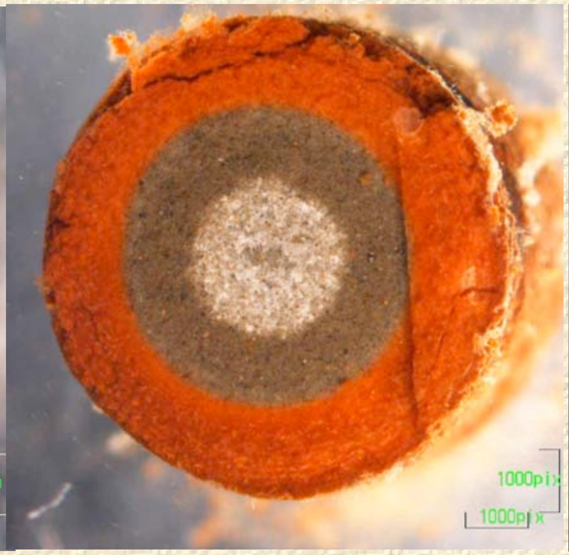
23°C
pH 2.4



23°C
pH 3.7



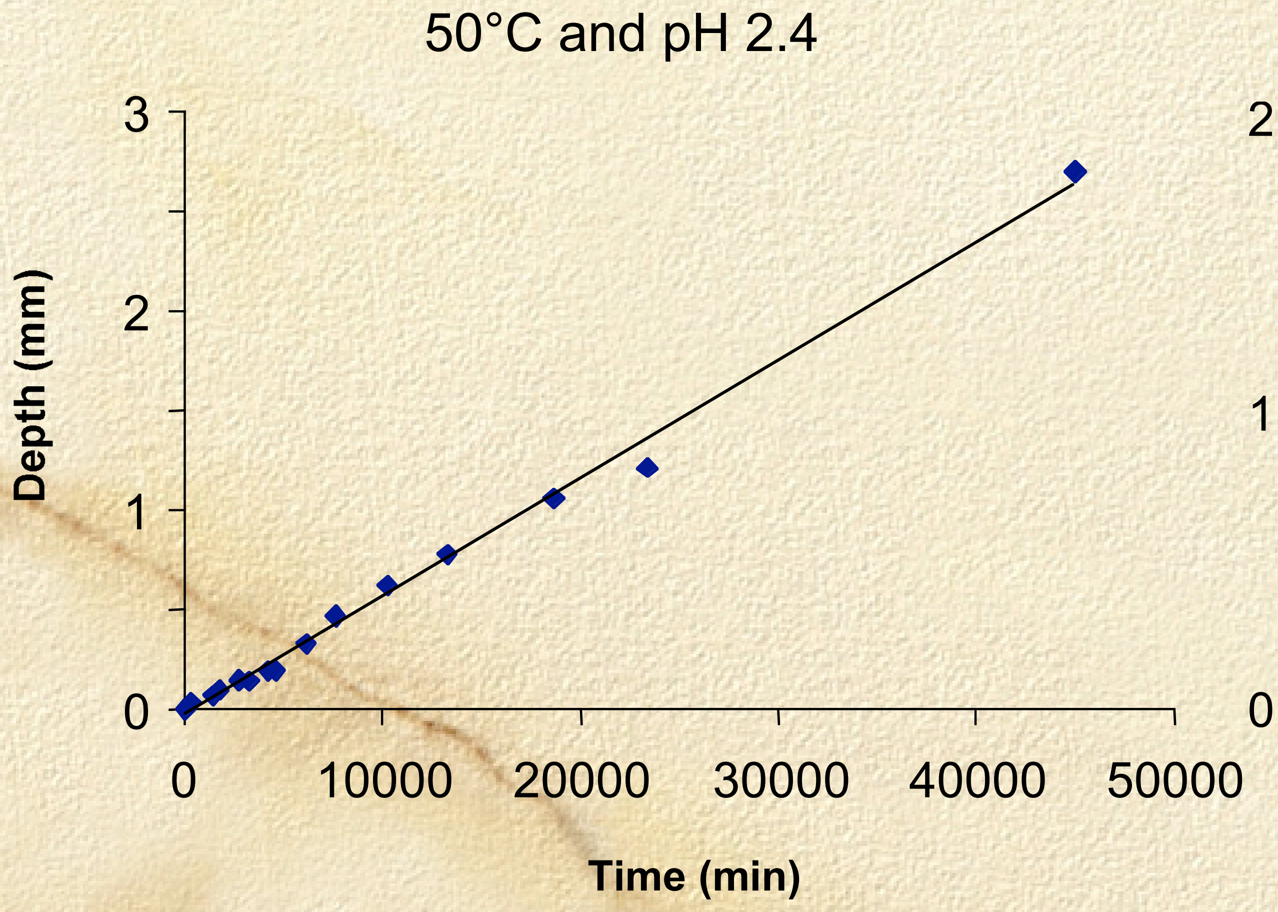
50°C
pH 2.4

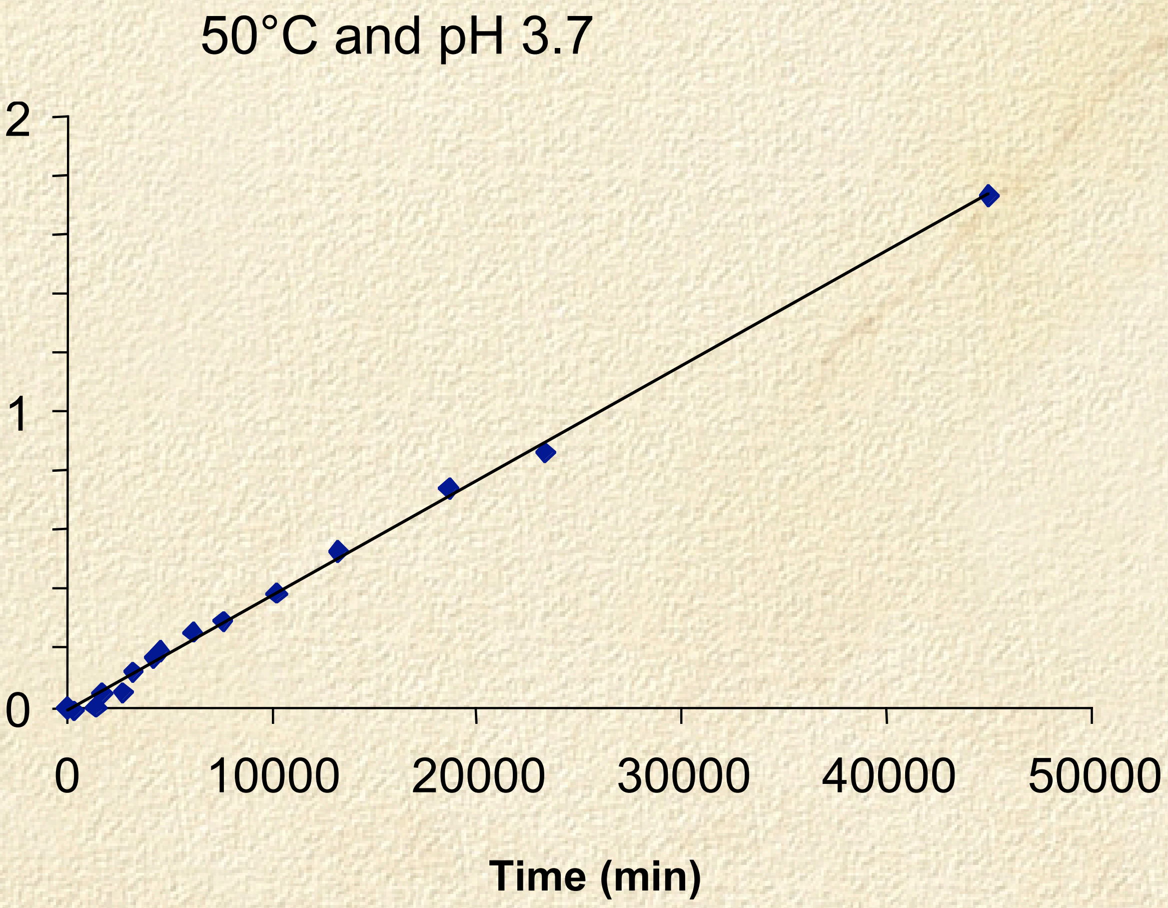


50°C
pH 3.7

Flow-Through Experiment
(Continuous fresh acid)

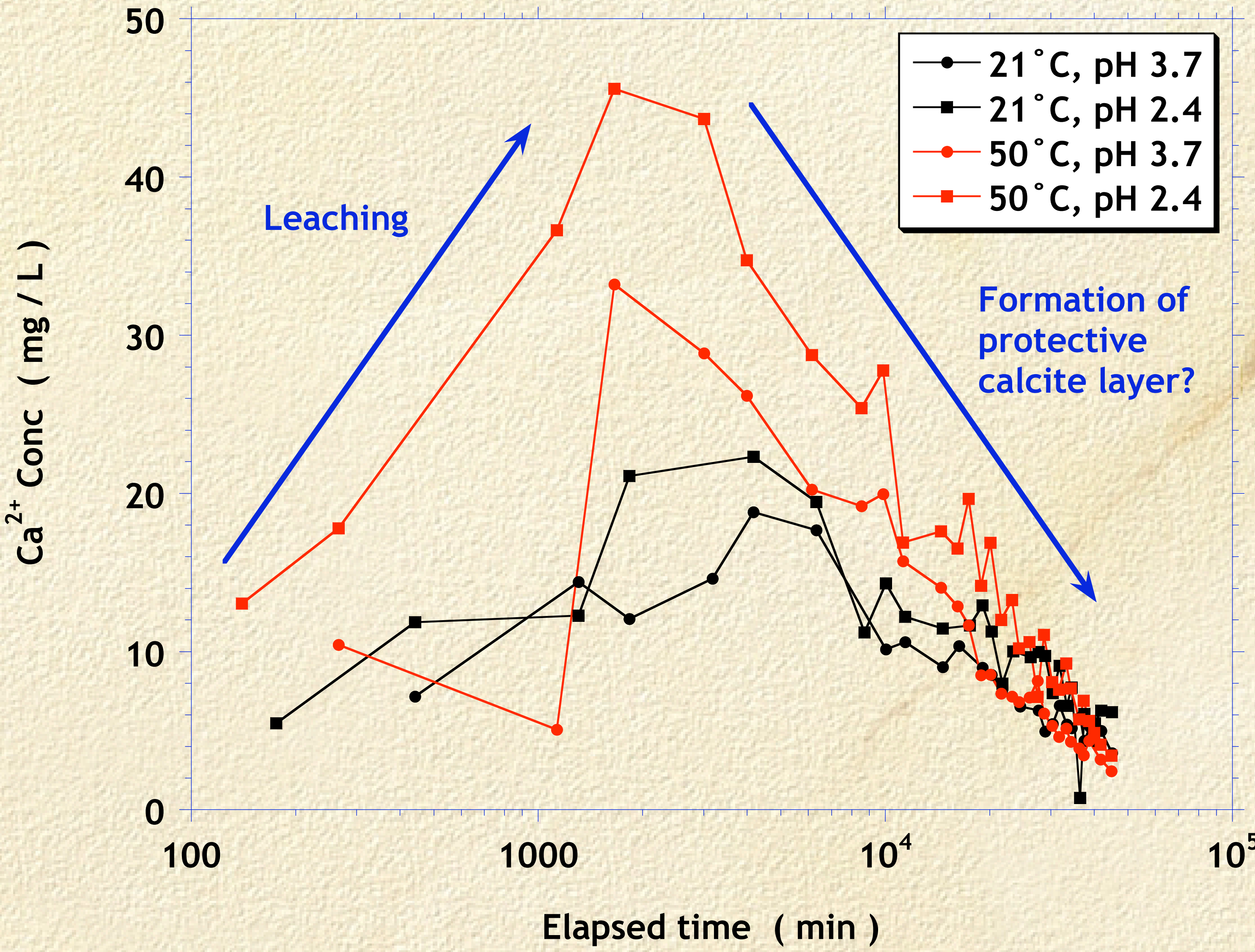
- Under typical conditions of a sandstone formation at ~1 km depth, the rate of attack would be roughly 2 - 3 mm per month *if fresh acid flowed over the cement*





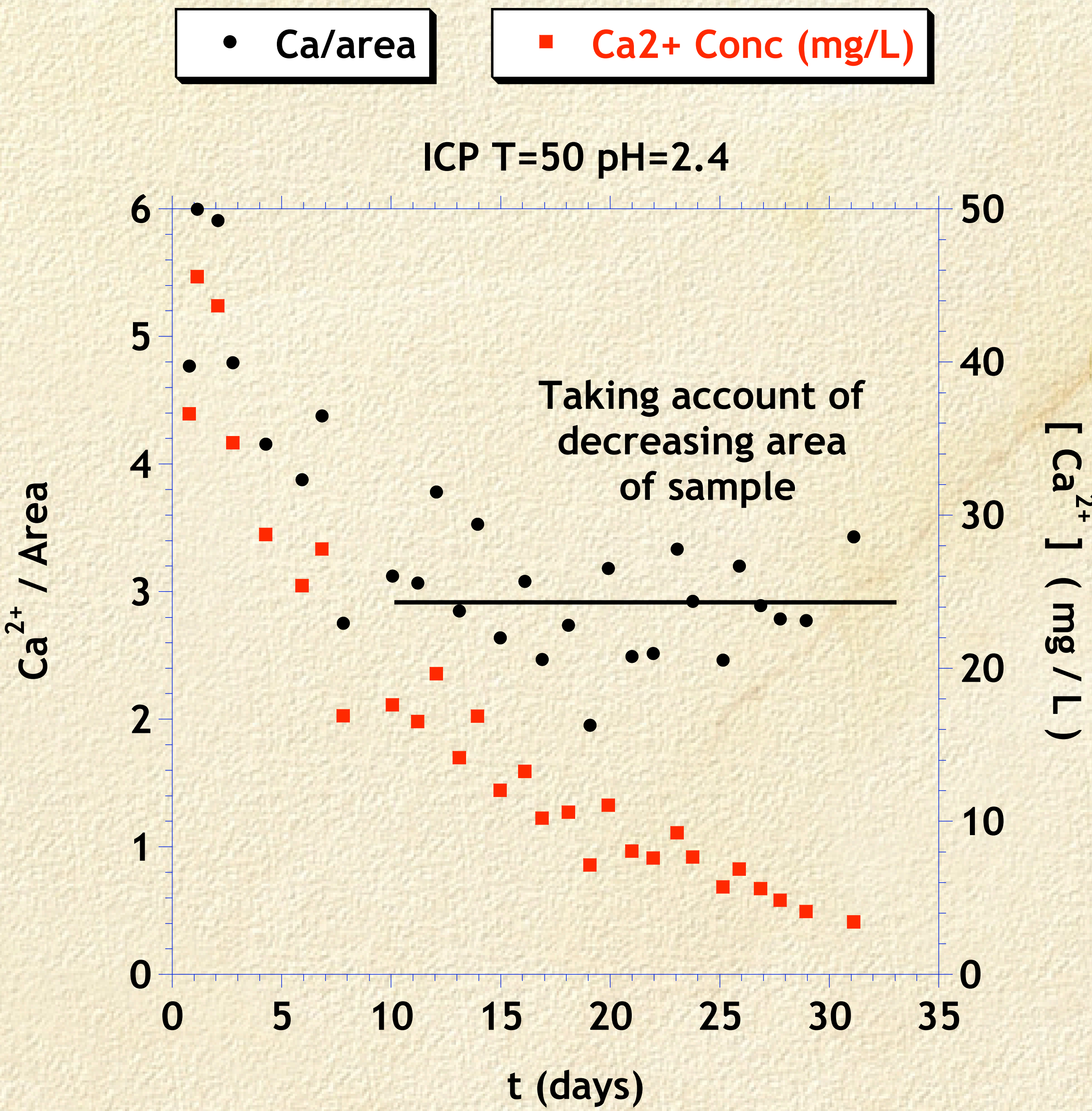
Composition of Effluent

- 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

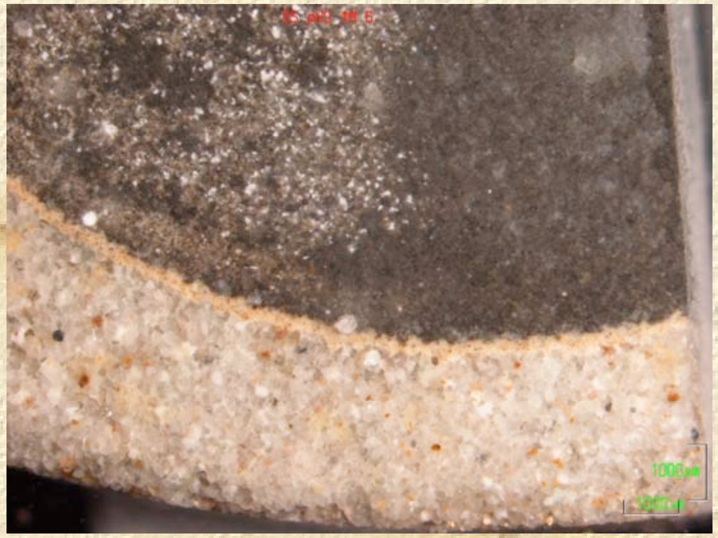
- Most of drop in Ca^{2+} results from decreasing area of unreacted core (see black dots)
- Probable increase in solute content at interface (but not diffusion control)



Batch 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)

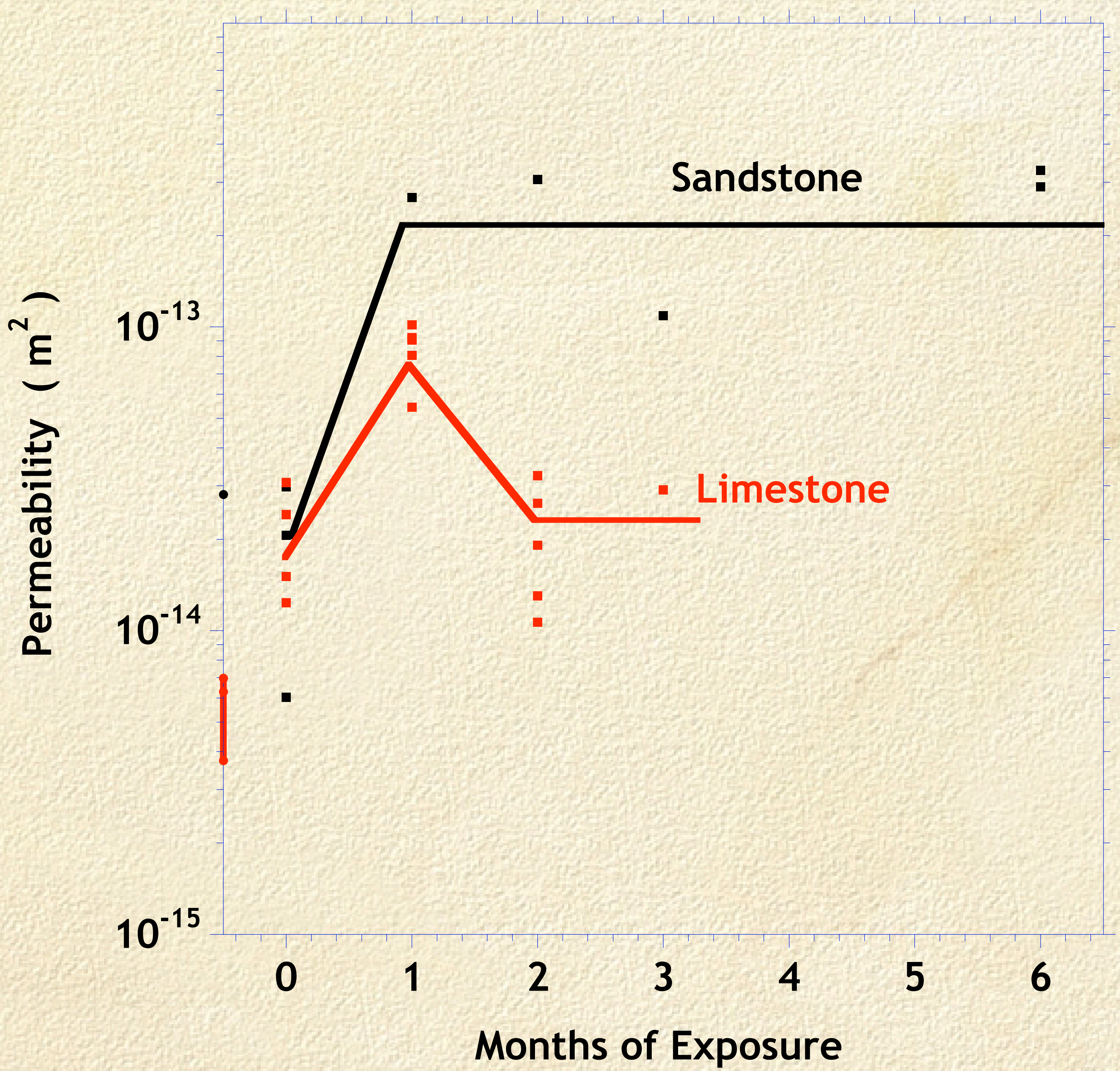
One Month

Three Months

Six Months

Permeability of Batch Samples

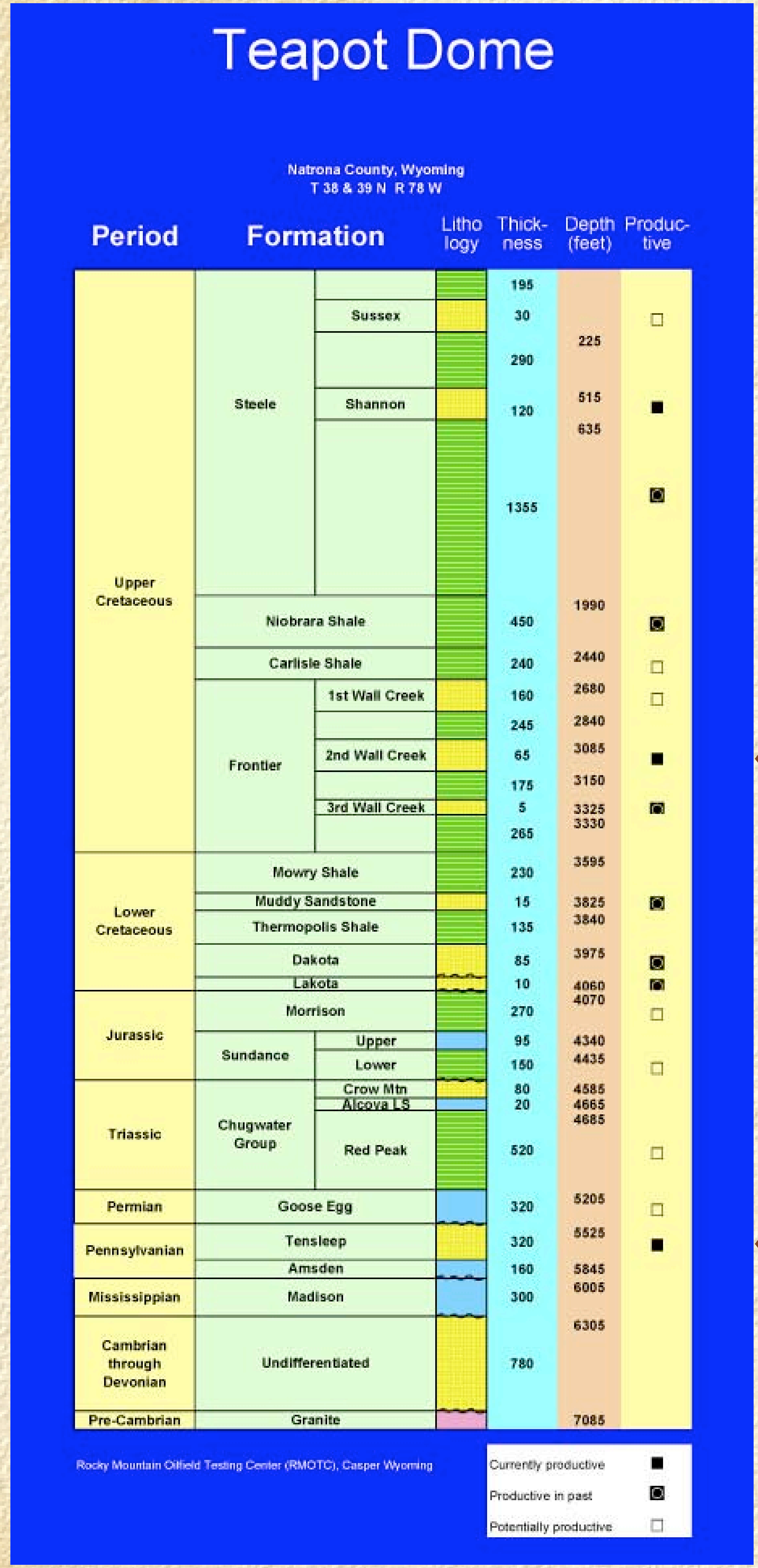
- Sandstone samples show 10-fold increase in 1 month
  - Equivalent to hole 0.4 mm in diameter
- Limestone shows little change



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

Wall Creek

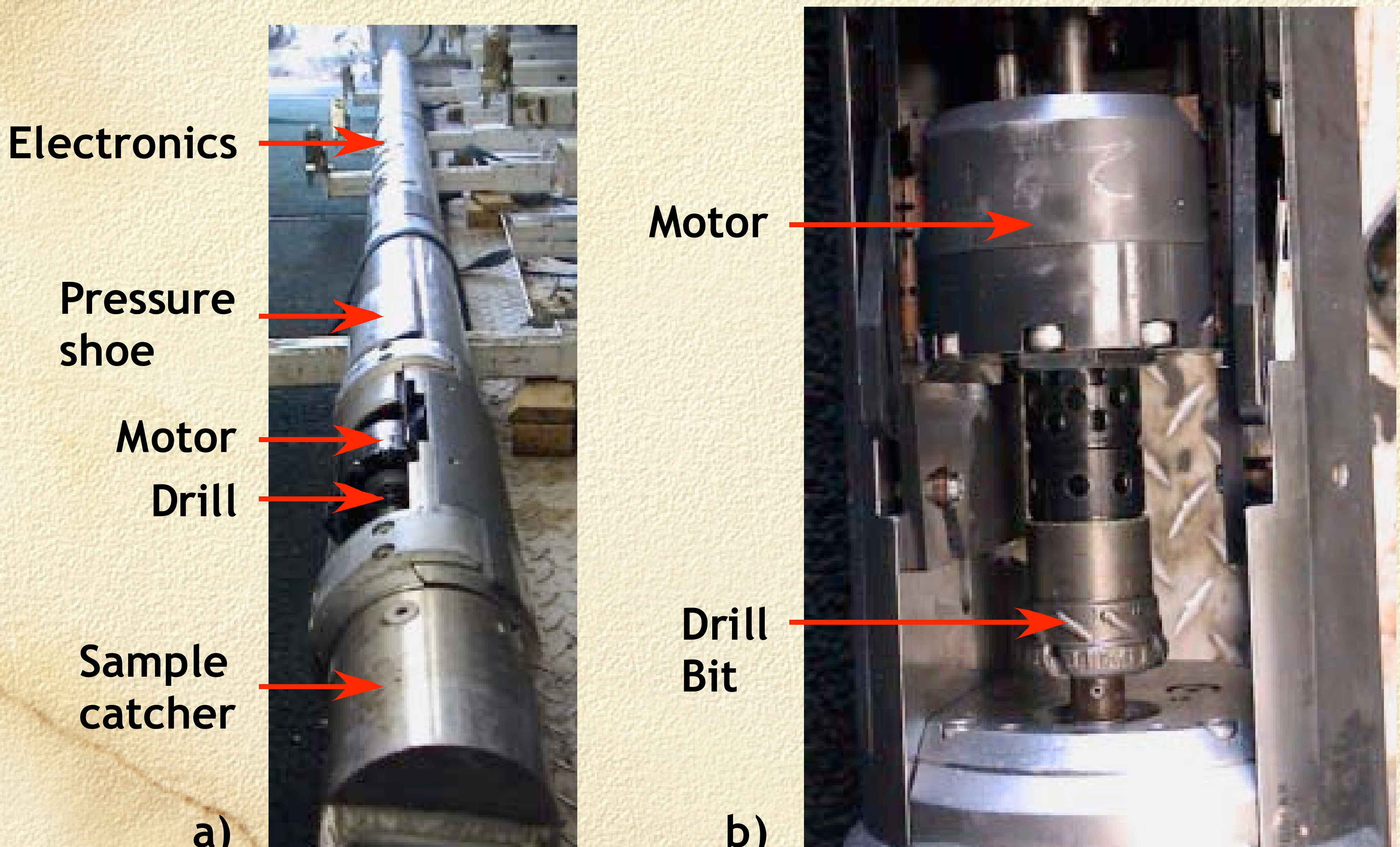


Tensleep

Teapot Dome Cement

- Cement retrieved from 3000-5000'
- 19 years old, made with formation water (high sulfate content) using class G cement + Flocele (cellophane flakes)
- Extremely complex microstructure, may be consequence of
  - Aging at high *T* & *P*
  - Use of sulfate-rich brine for mixing cement

Schlumberger Coring Tool

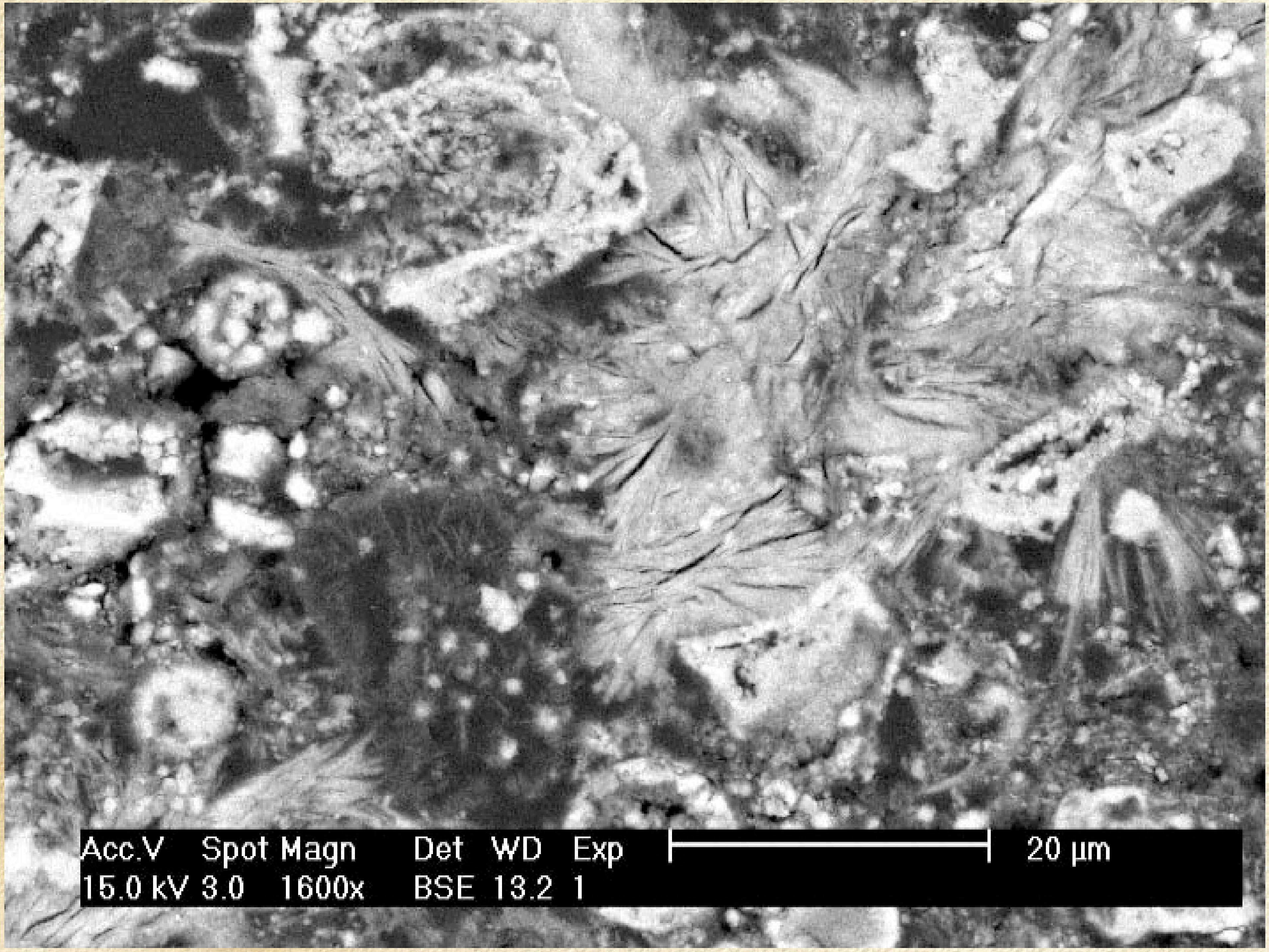


Retrieving the Core

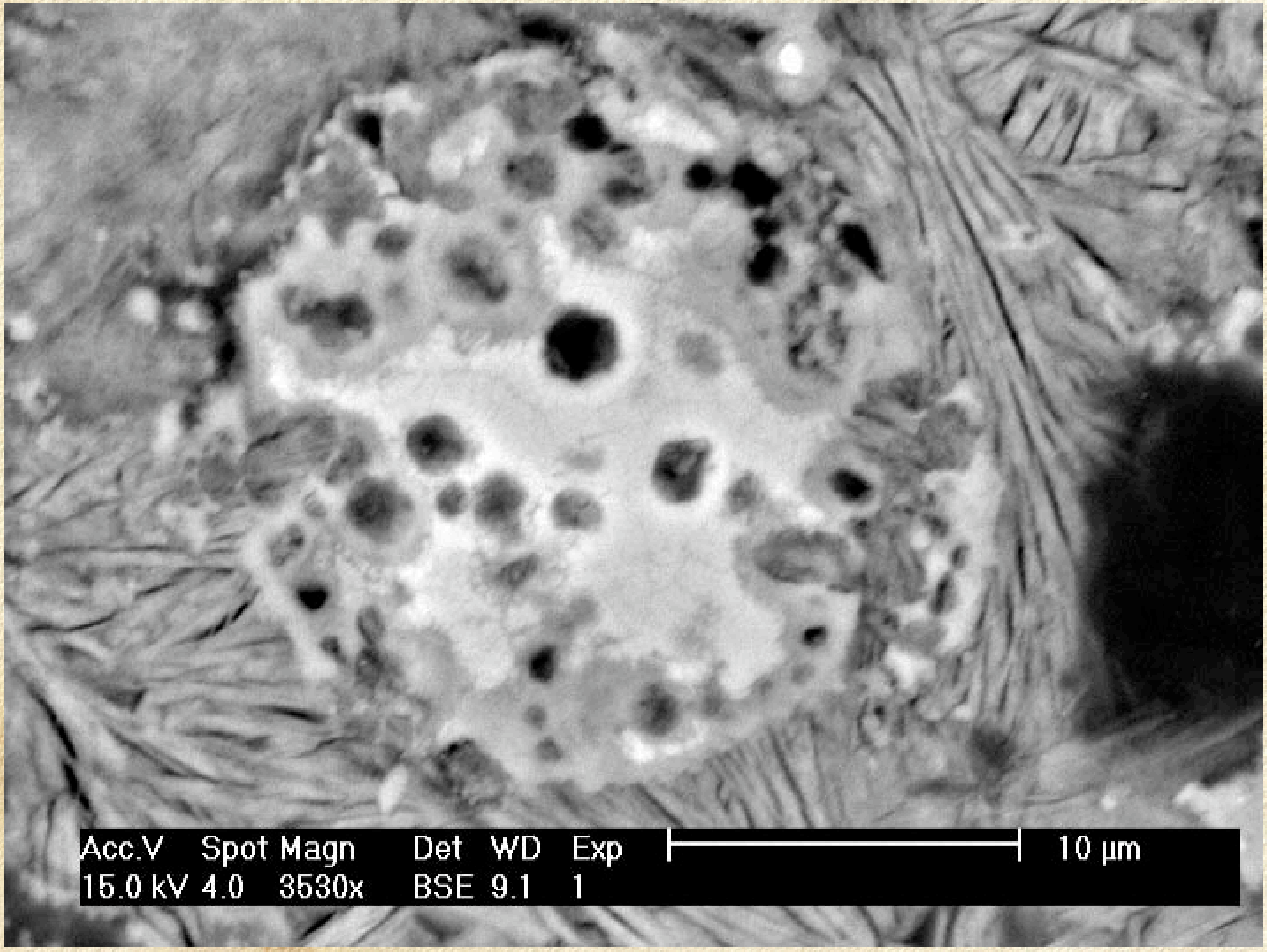
Cement + Casing

Cement/Casing Interface

Complex Microstructure



Crystals within Crystals...



Program

- Analyze phases & composition of Teapot cement
- Test durability of Teapot cement
- Synthesize this recipe
  - Age at high *T* & *P* at NETL lab
  - Age at ambient *P* at Princeton
  - Compare properties
- If high *P* proves important, repeat durability tests after curing at high *P*

Tensleep Brine Composition

Cations	mg/L	meq/L	Other
Potassium	90.300	2.3100	
Sodium	642.00	27.900	
Calcium	268.00	13.400	
Magnesium	34.200	2.8100	
Iron-Total	0.55000	0.020000	
Anions			
Sulfate	887.00	18.500	
Chloride	870.00	24.500	
Carbonate	1.0000	0.0000	
Bicarbonate	148.00	2.4300	
Hydroxide			
Nitrogen, Ammonia as N			
Nitrogen, Nitrate + Nitrite as N			
Solids			
TDS @180C	3220.0		
Total Solids, NaCl Equivalents	2200.0		
Chloride as NaCl	1430.0		
NaCl % of TDS			42.100
Sample Conditions			
pH (s.u.)			7.9300
Ionic Strength (u)			268.00
Accuracy (Sigma)			-1.2300
Other Properties			
Calcium Hardness asCaCO3	669.00		
Magnesium Hardness as CaCO3	141.00		
Total Hardness as CaCO3	810.00		
Sodium Adsorption Ratio	9.7900		
Specific Gravity	1.0020		
Conductivity (uhmo/cm)			4740.0
Resistivity, 68F (Ohm meter)			2.1100
Probabled Mineral Residue, Dry			
NaCl	1360.0		
CaSO4			
Na2SO4	389.00		
Ca(HCO3)2	197.00		
MgSO4	169.00		
KCl	98.700		
Organics			
O&G (Total Recoverable)	2.2000		

Leaking well modeling and CO_2 interaction with cured well cement

by

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Well Bore Integrity Workshop
Houston, Tx, 4-5 April 2005

Outline

- Work performed under contract CCP2 C04042, signed by JIP Suboperator 15-October-04
- Modeling scenarios of CO_2 storage and leakage
- Changes in permeability, porosity and weight of cured well cement (concrete) after exposure to CO_2 saturated brine in a HPHT autoclave
- Changes in mineral composition by SEM and XRD analyses due to the same exposure
- Mechanical parameters from acoustic measurements and scratch tests before and after the exposure
- Capillary entry pressure of CO_2 into cured well cement (concrete) before and after exposure

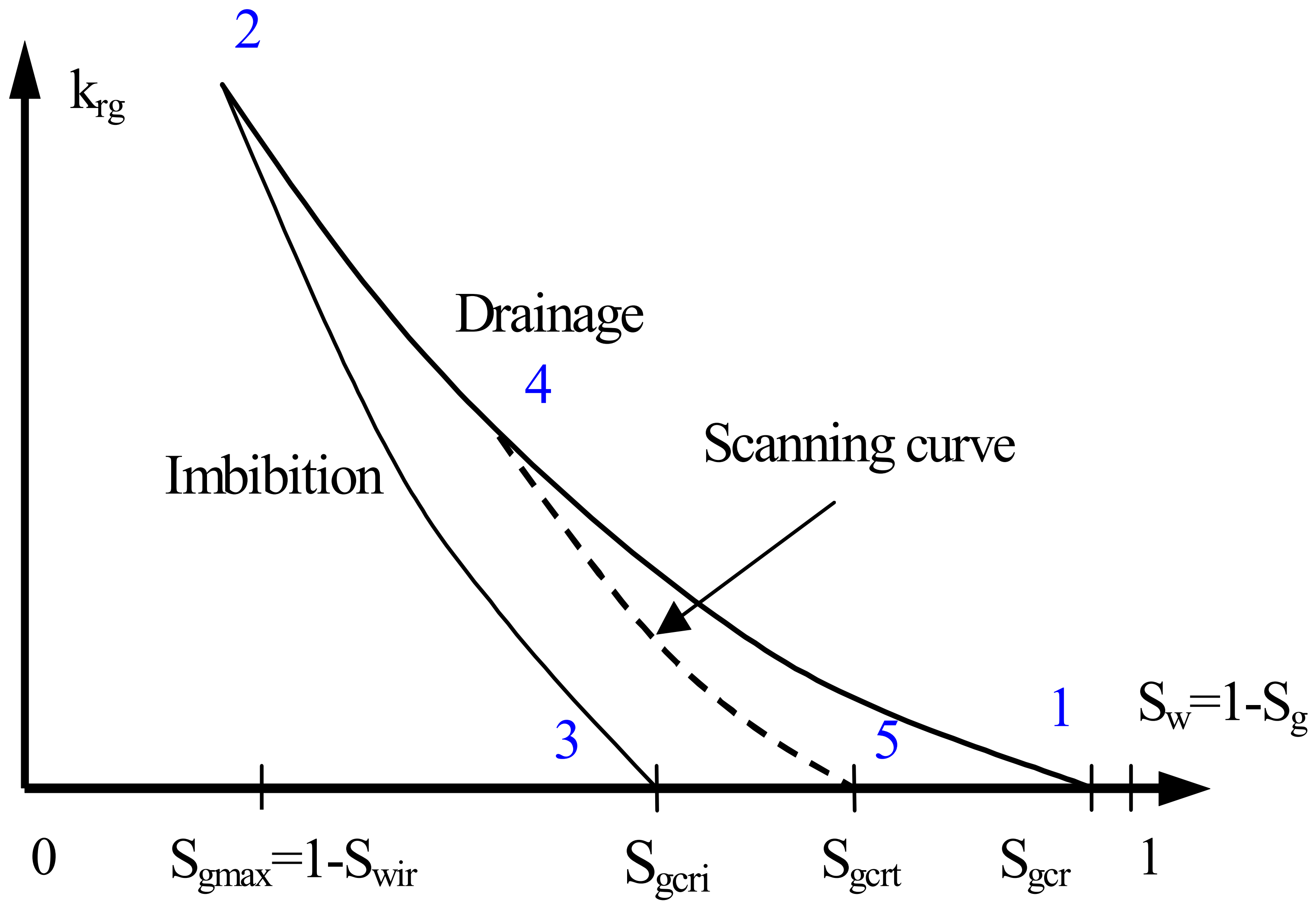
Simulation model for CO_2 storage in aquifers

- A flexible reservoir simulation model was constructed

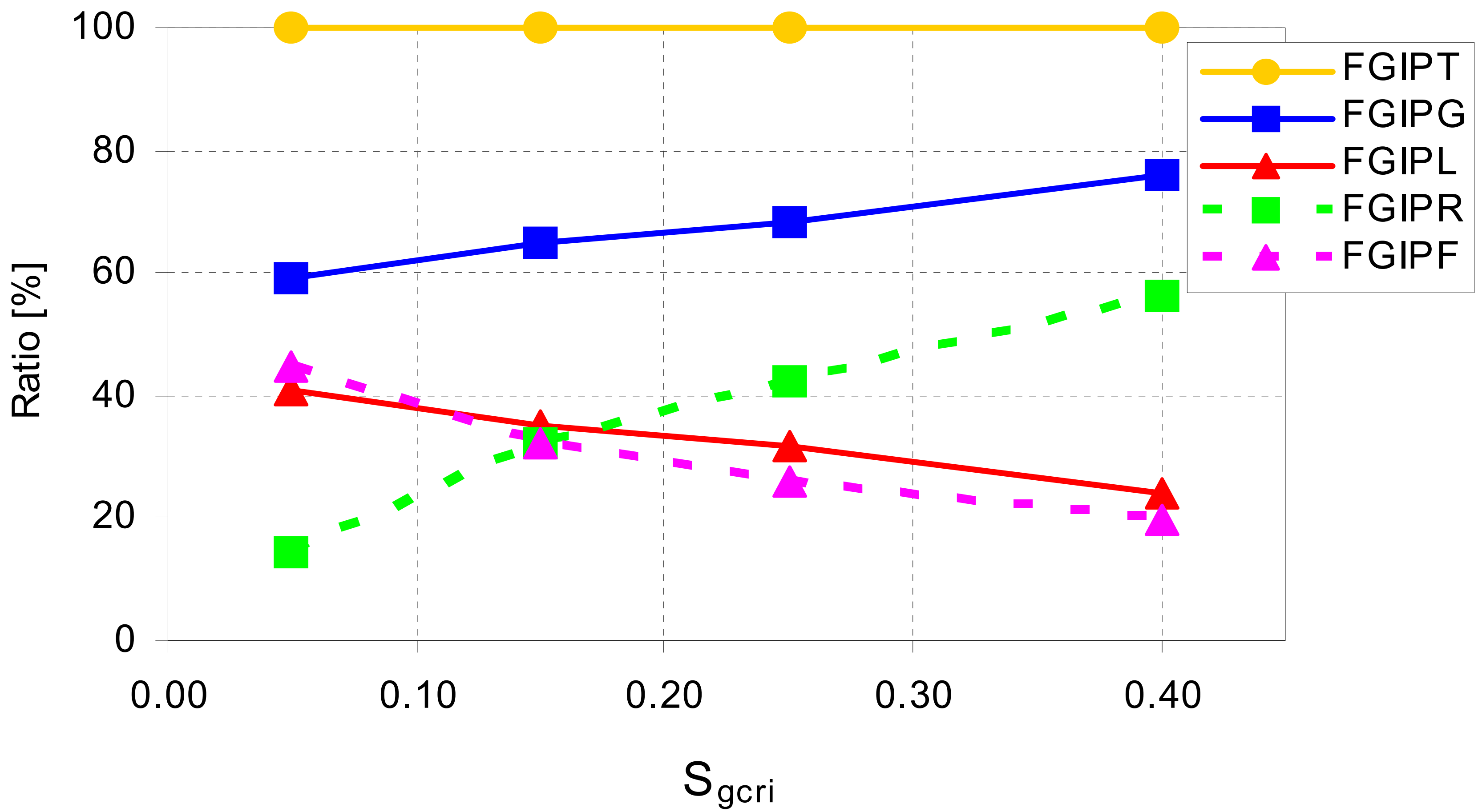
- Amount of CO_2 dissolved in the aqueous phase as a function of the pressure and temperature in the aquifer, was explicitly set by use of laboratory pVT data of CO_2/brine mixtures

- Density and viscosity of both CO_2 and water at aquifer conditions were set explicitly.

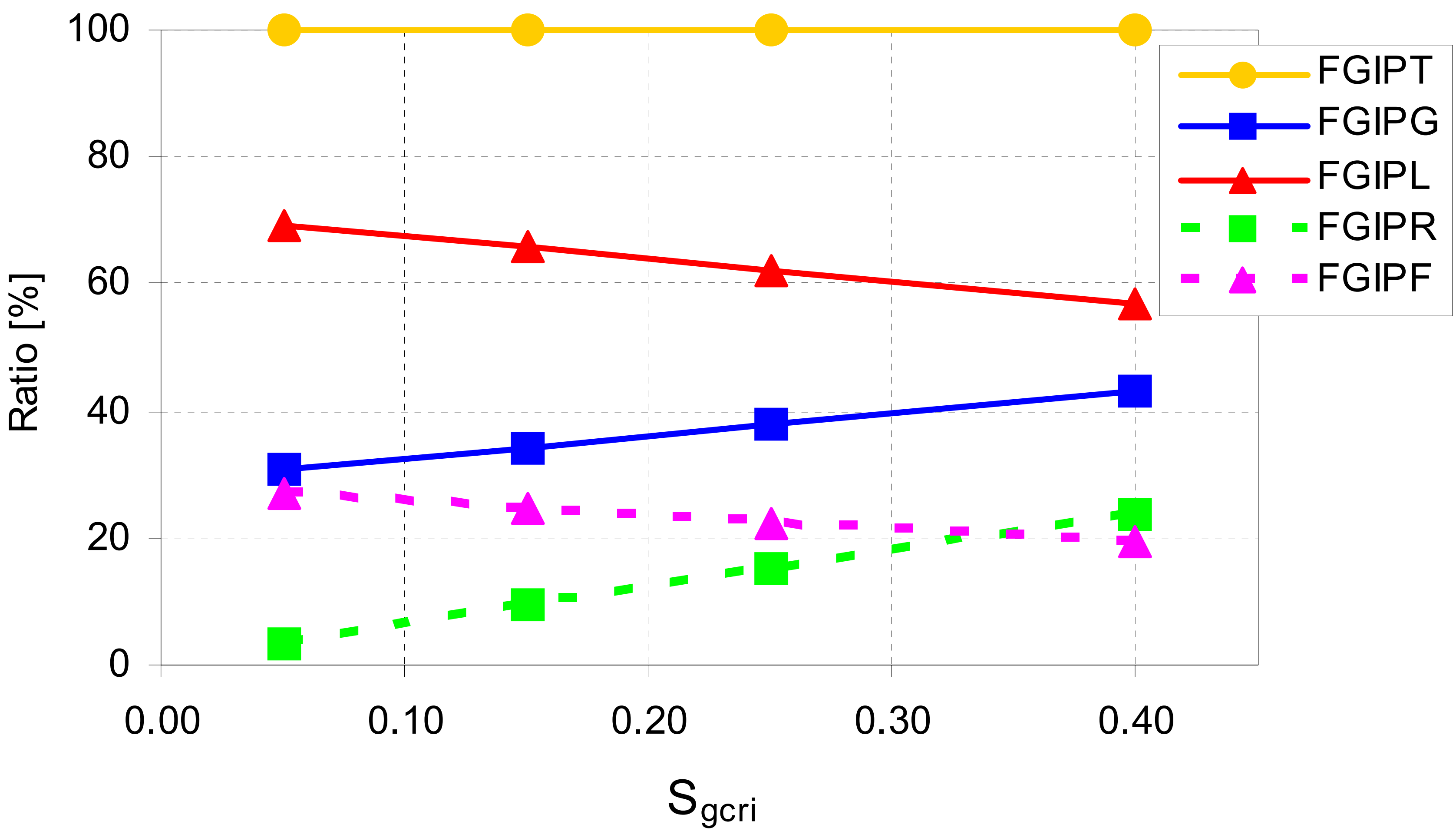
Gas-water relative permeability hysteresis model



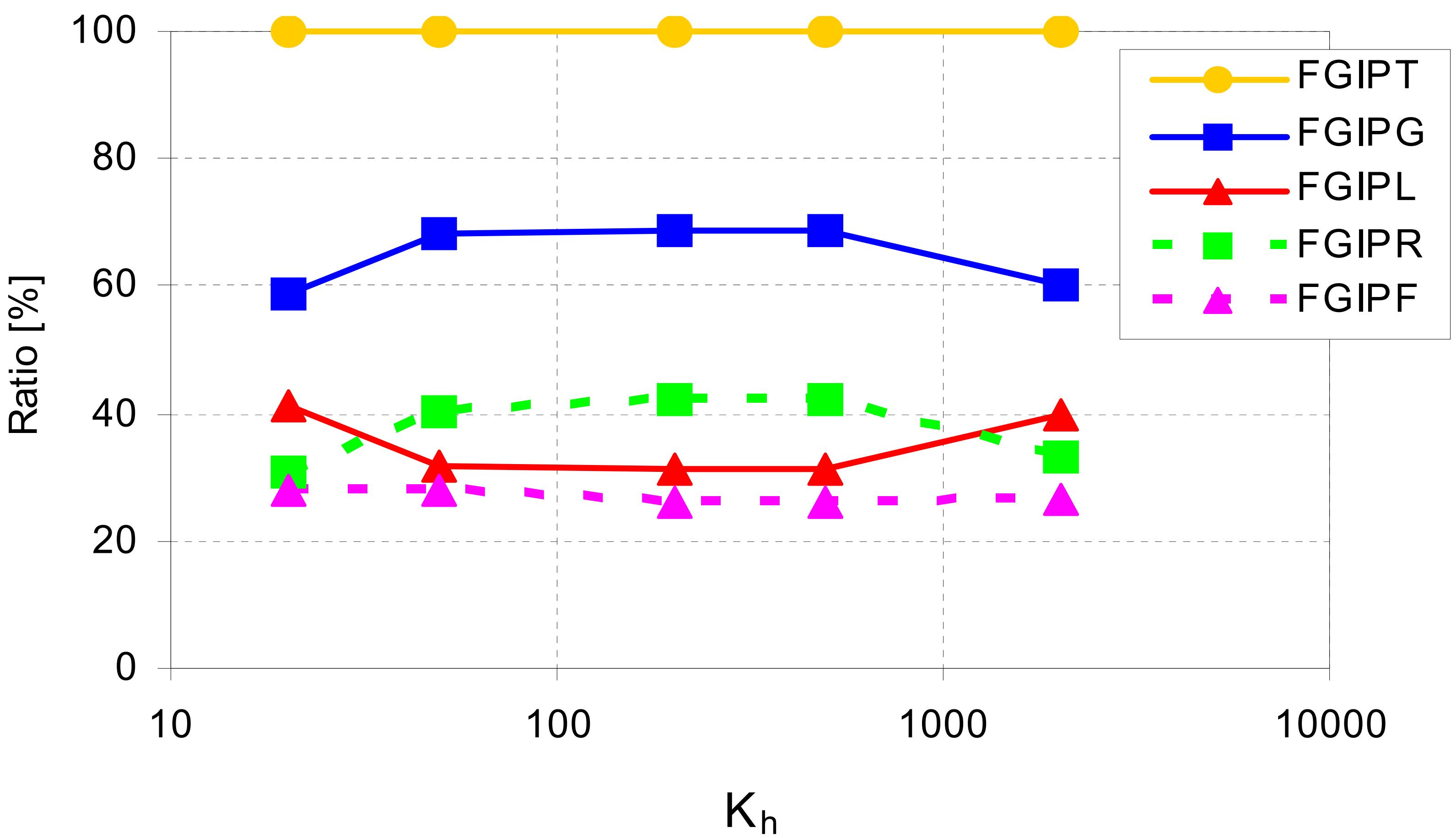
Effect of critical gas saturation on CO_2 distribution in the aquifer after 1000 years for K_h=200 mD, K_v/K_h = 0.01



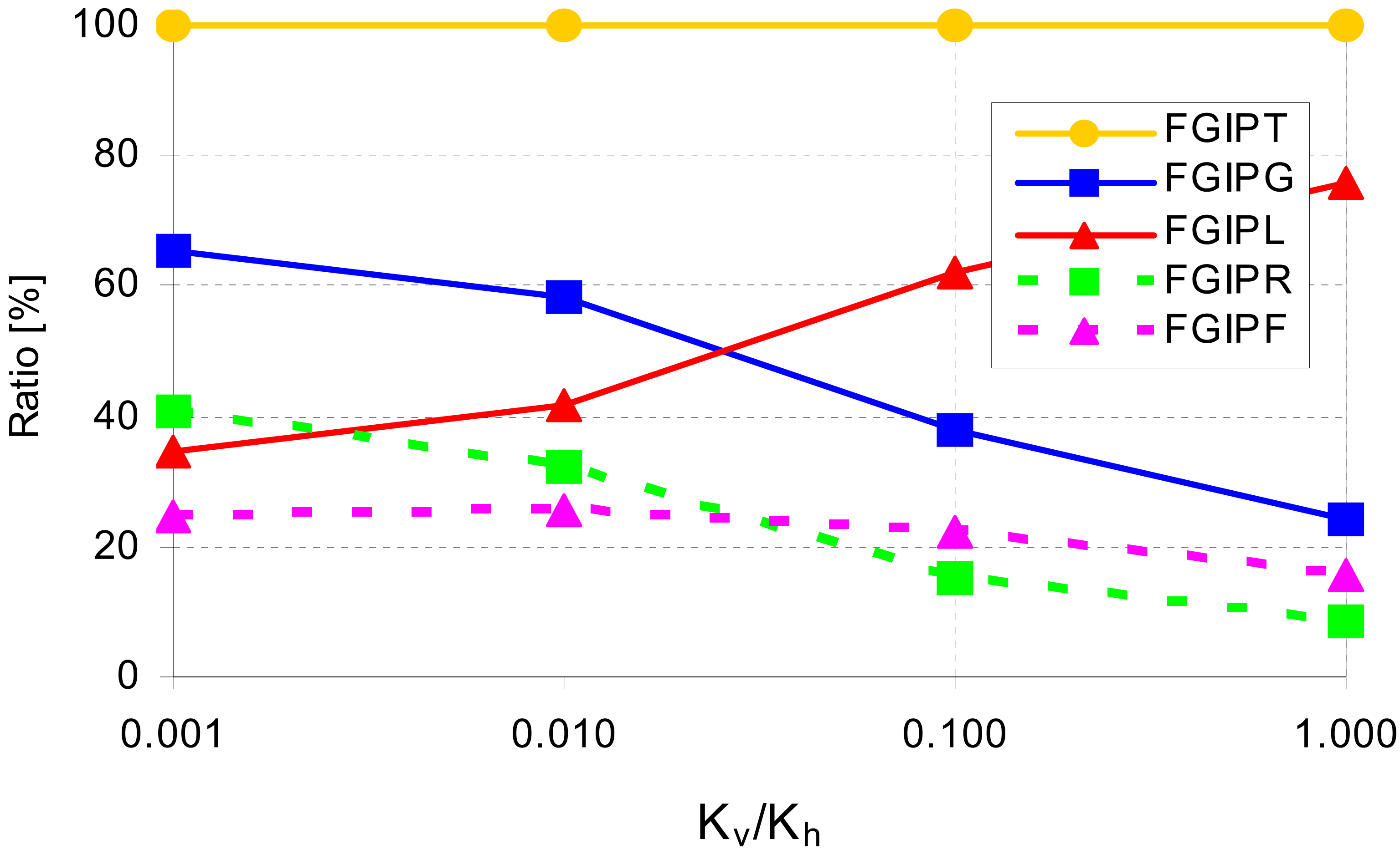
Effect of critical gas saturation under water imbibition on CO_2 distribution in the aquifer after 1000 years for K_h=2000 mD, K_v/K_h = 0.1



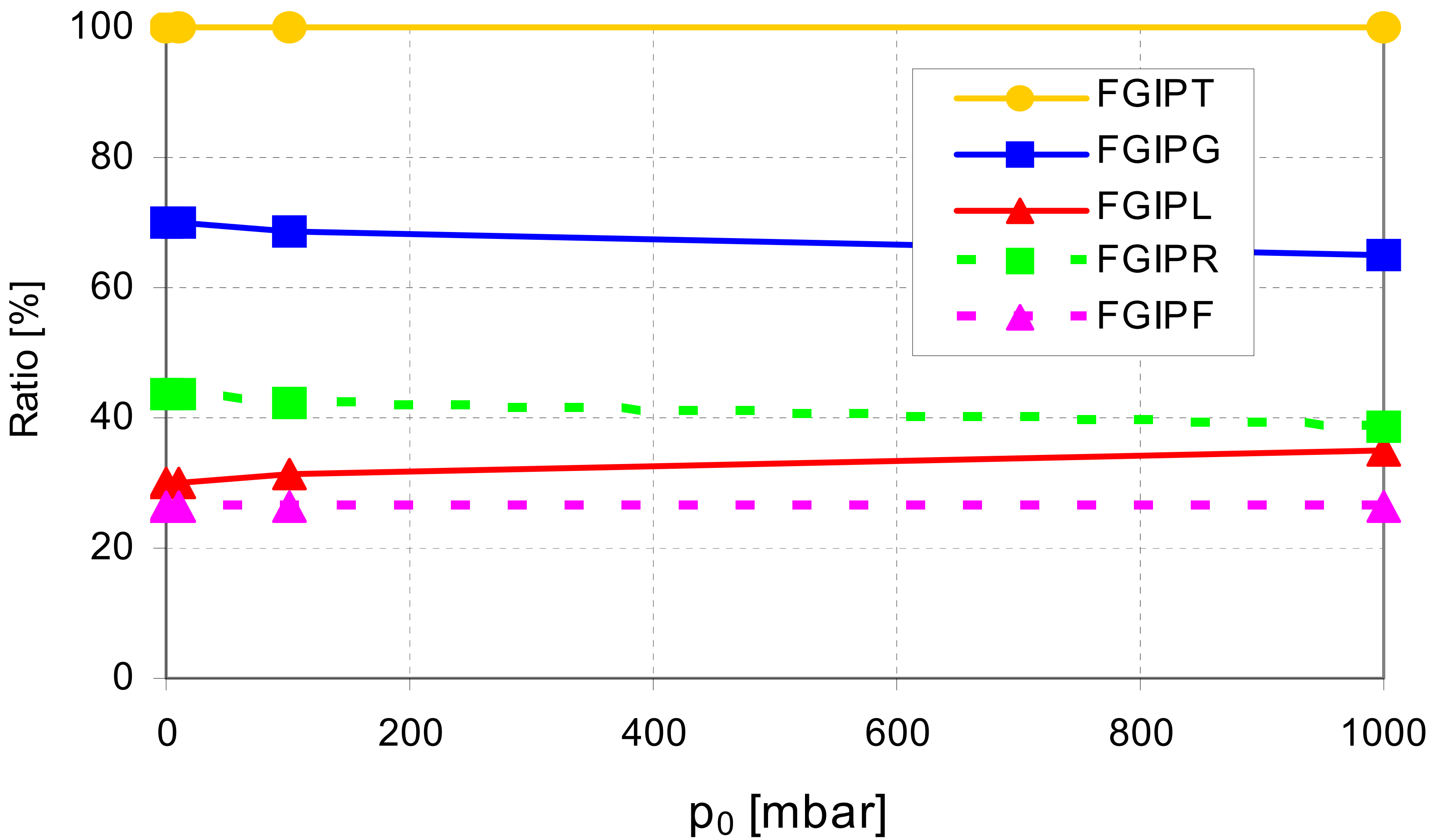
Effect of K_h on CO_2 distribution in the aquifer after 1000 years for $K_v/K_h = 0.01$



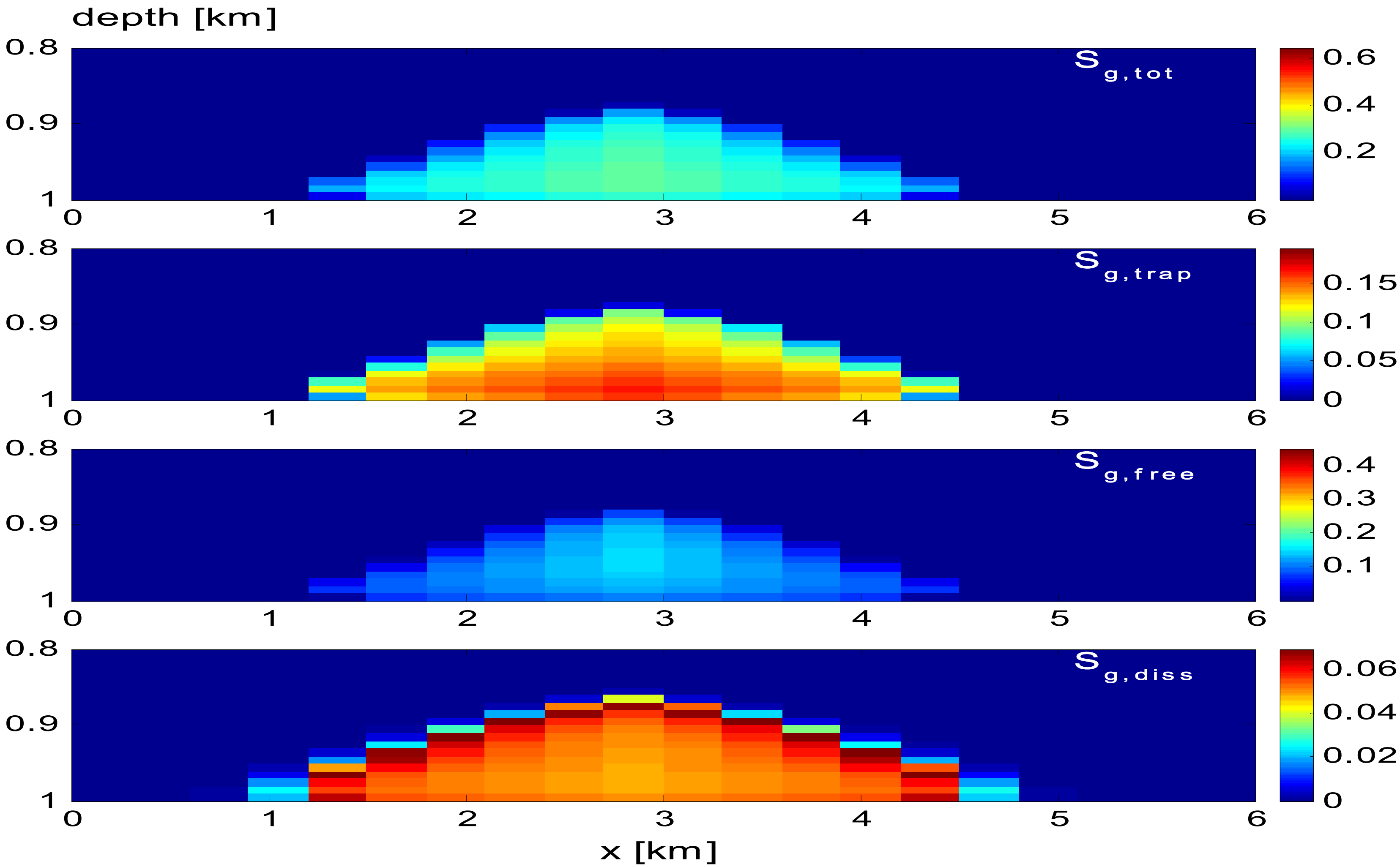
Effect of K_v/K_h on CO_2 distribution in the aquifer after 1000 years for K_h = 2000 mD



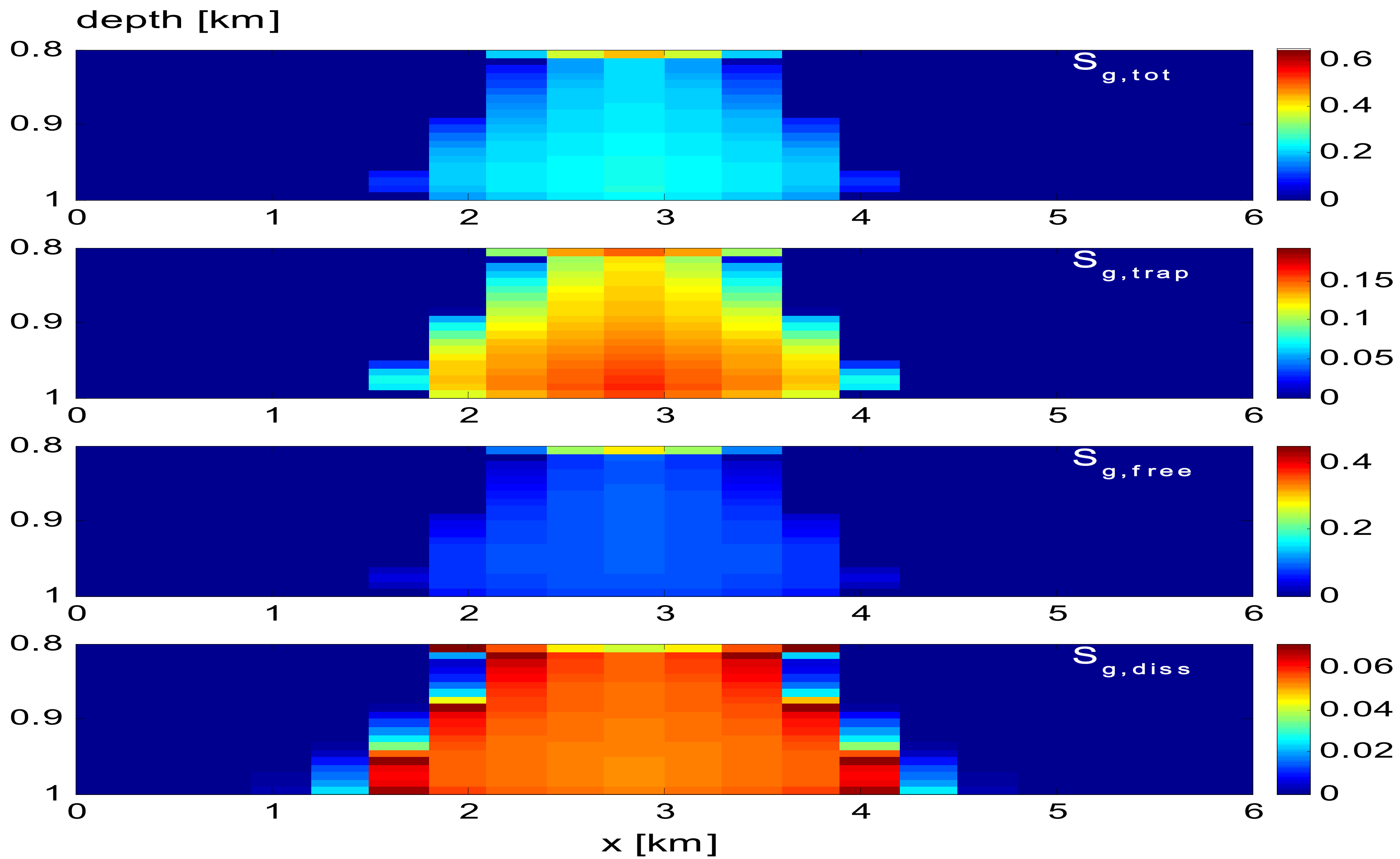
Effect of capillary pressure on CO_2 distribution in the aquifer after 1000 years for K_h=200 mD, K_v/K_h = 0.01



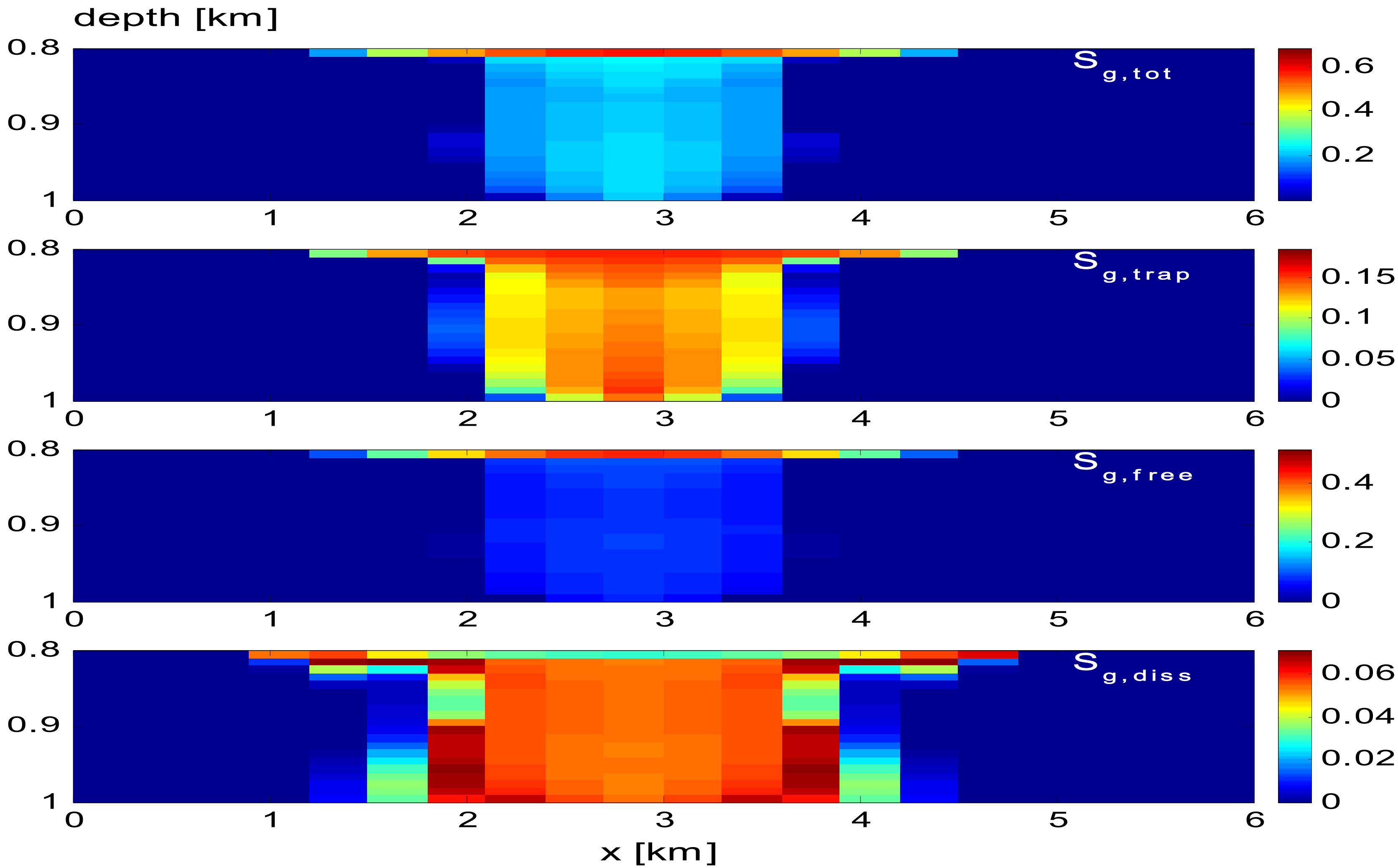
Cross-section of CO_2 plume in the aquifer after 1000 years for K_h = 200 mD, K_v/K_h=0.001



Cross-section of CO_2 plume in the aquifer after 1000 years for K_h = 200 mD, K_v/K_h=0.01



Cross-section of CO_2 plume in the aquifer after 1000 years for K_h = 200 mD, K_v/K_h=0.1



Conclusions on storage relevant for CO_2 leakage modeling

- Dissolution of CO_2 in aquifer water is the dominant mechanism of CO_2 storage in saline aquifers provided that the vertical communication allows for convective mixing of the CO_2 plume into the aquifer brine.
- The amount of trapped CO_2 gas due to the gas-water capillary pressure and relative permeability hysteresis decreases when k_v/k_h increases. The percentage of trapped gas is reduced to less than 30 % at a k_v/k_h ratio of 0.1

Leaking well modeling?

- To day no satisfactory robust well model for the industry exists to model leakage trough abandoned wells with a time varying finite permeability and porosity due to deterioration of cement plugs.
- To get quantitative estimates of the leakage risk it is important to understand the mechanisms and time scales involved in such deterioration processes.
- It is possible to place production wells controlled at BHP at various places inside the CO_2 plume and study how much leaks out.

Leaking well modeling (cont)

- A simplified approach is simply to assume that all CO_2 entering the well will reach the surface.
- The only controlling parameter will be the well inflow parameter. Since no information about the well inflow is available this must be considered as a parameter free to adjust.
- This also means that the model has no predictive power except for studying the effect of different reservoir parameters for artificial chosen well inflow parameters.

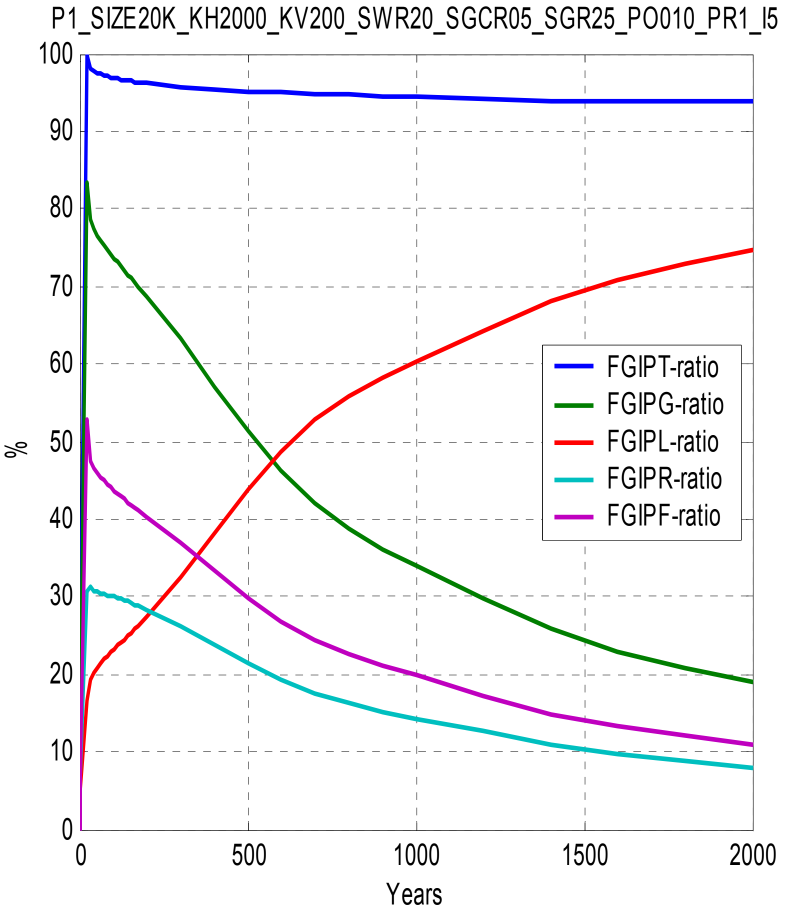
Leaking well modeling (cont)

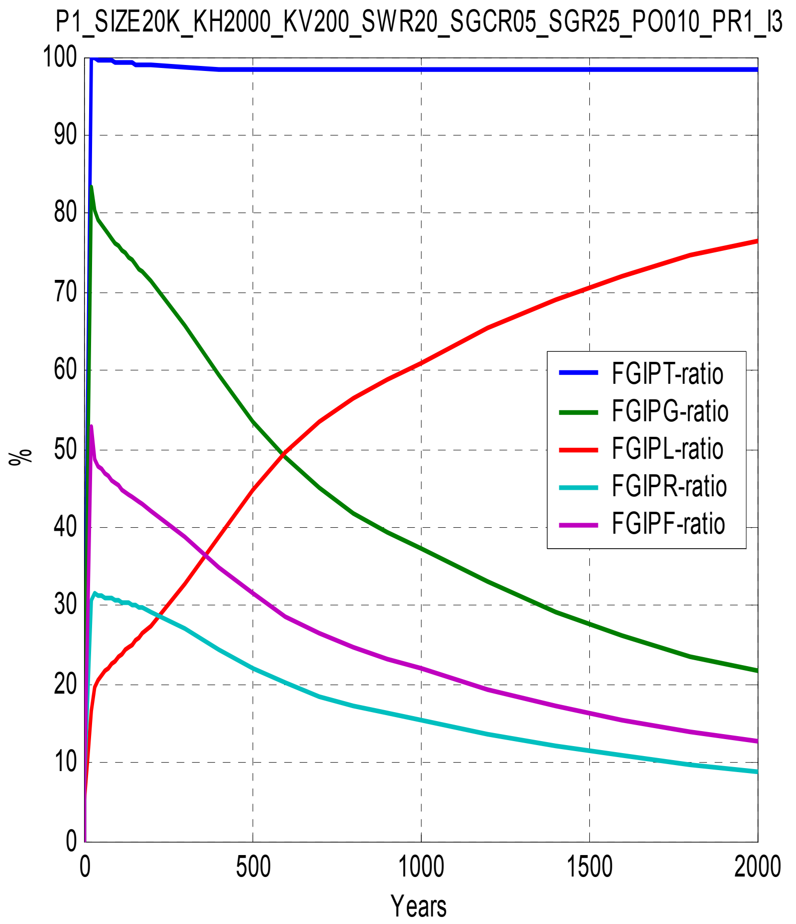
- For all simulations the injection last for 25 years.
- *Simulation names*
- P1: Leaking well perforated in layer K=1
- P1_5: Leaking well perforated in layer K=1-5
- SIZE20K: Grid: 20 x 20 x 20
- KH2000: K_h = 2000 mD
- KV200: K_v = 200 mD
- SWR20: S_{wr} = 20%
- SGCR05: S_{gcrd} = 5%
- SGR25: S_{gcri} = 25%
- PO010: P_0 = 10 mbar
- WPI002: WPIMULT = 0.02
  - If not specified WPIMULT = 1.0
- PR1_I5: Production well placed in (I,J)=(5,10) [injection well is in (I,J)=(10,10)]
  - If not specified (I,J)=(10,10)

Leaking well modeling; *Placement of leaking well*

- We have done simulations for different placements of the leaking well.
- The worst case scenario is to place the well vertically above the injection point which is in the bottom of the model.
- Other well positions studied are about 1.5 km and about 2.1 km horizontally from the injection point (5 and 7 grid blocks respectively).
- As expected this has a large impact on how much leaks out as shown in Figure 34.

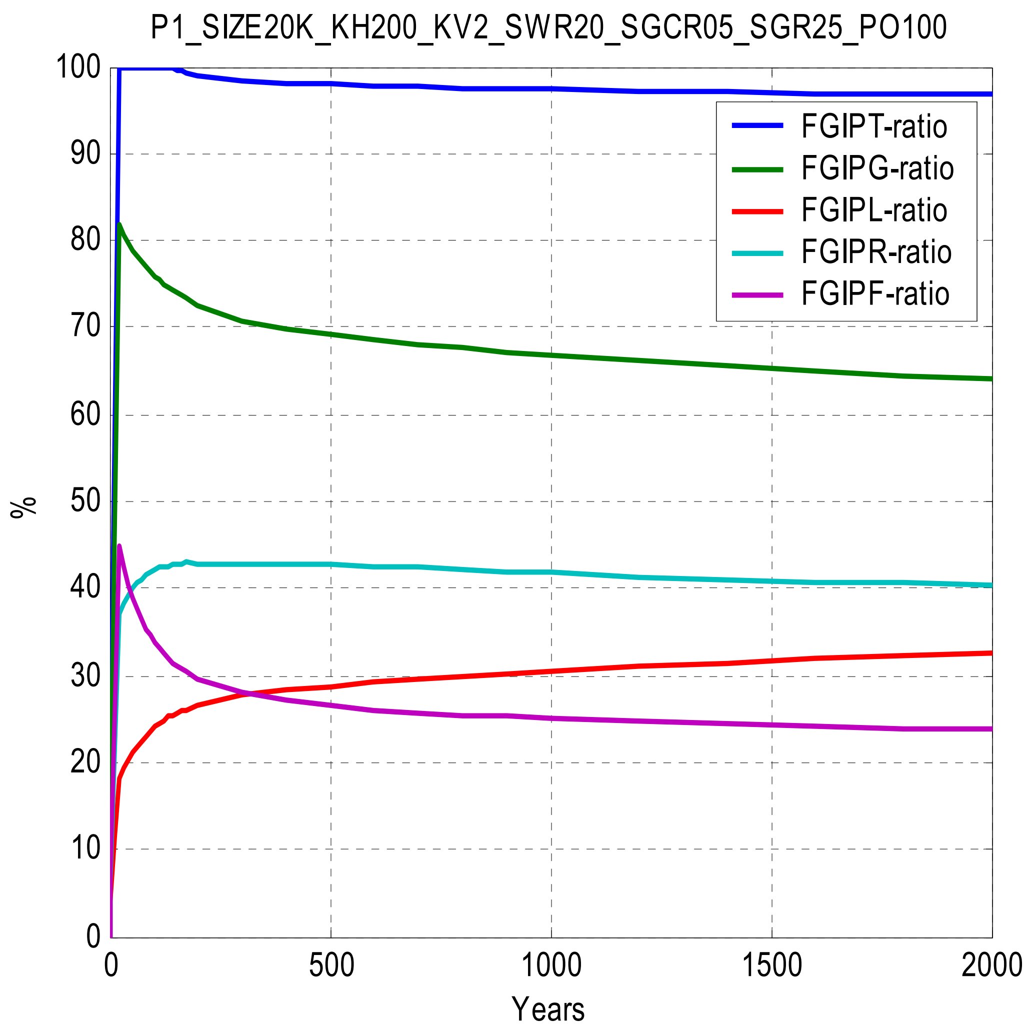
Distribution of CO_2; Leaking well located 1.5 and 2.1 km from the injection point





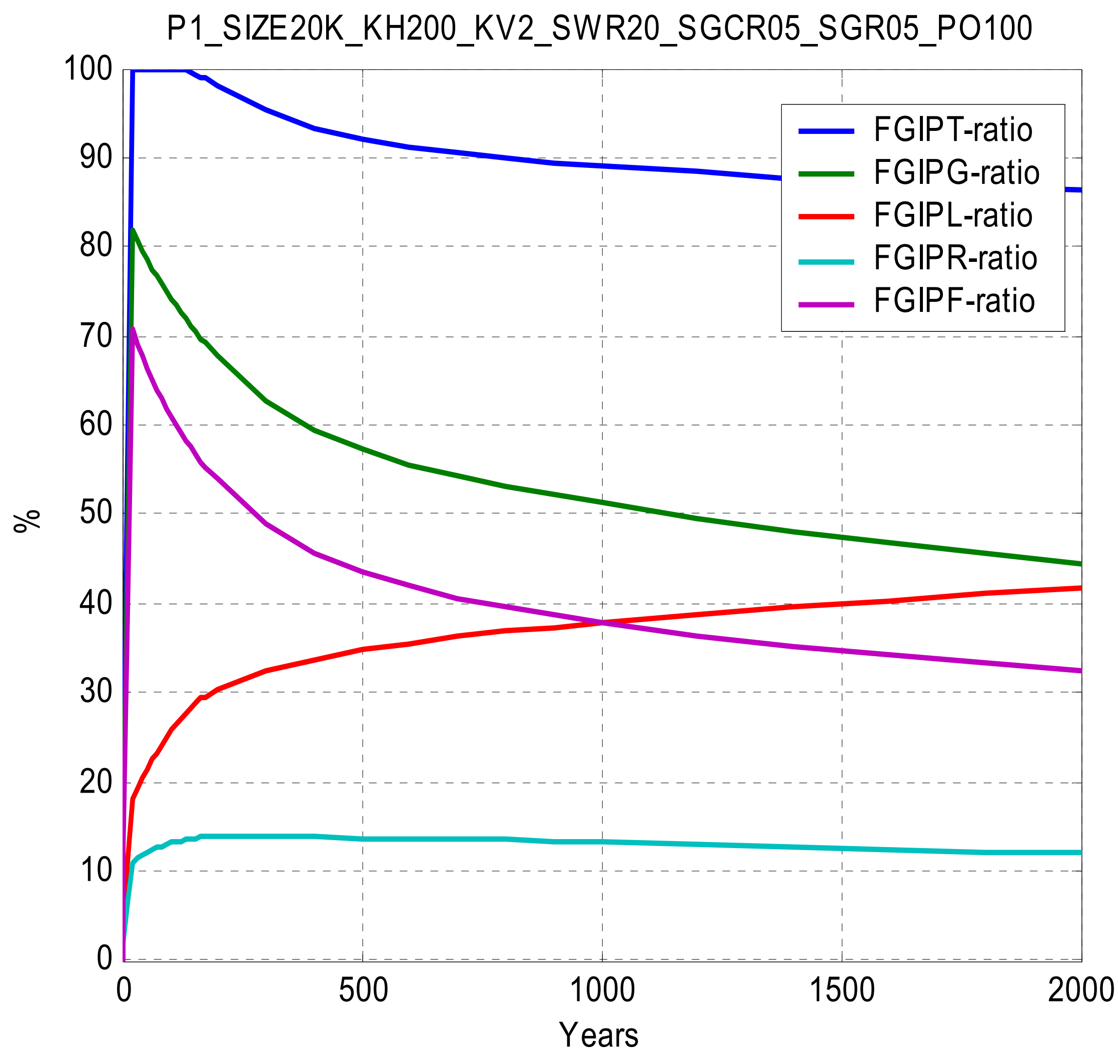
Distribution of CO_2; *Effect of imbibition S_{gcri}*

- By reducing the imbibition critical gas saturation S_{gcri} from 25% to 5% for fixed drainage critical gas saturation S_{gcrd} = 5% more CO_2 leaks out (next slides).



Distribution of CO_2; *Effect of imbibition S_{gcri}*

- Case of imbibition critical gas saturation S_{gcri} at 5% low for fixed drainage critical gas saturation S_{gcrd} = 5%, more CO_2 leaks out.

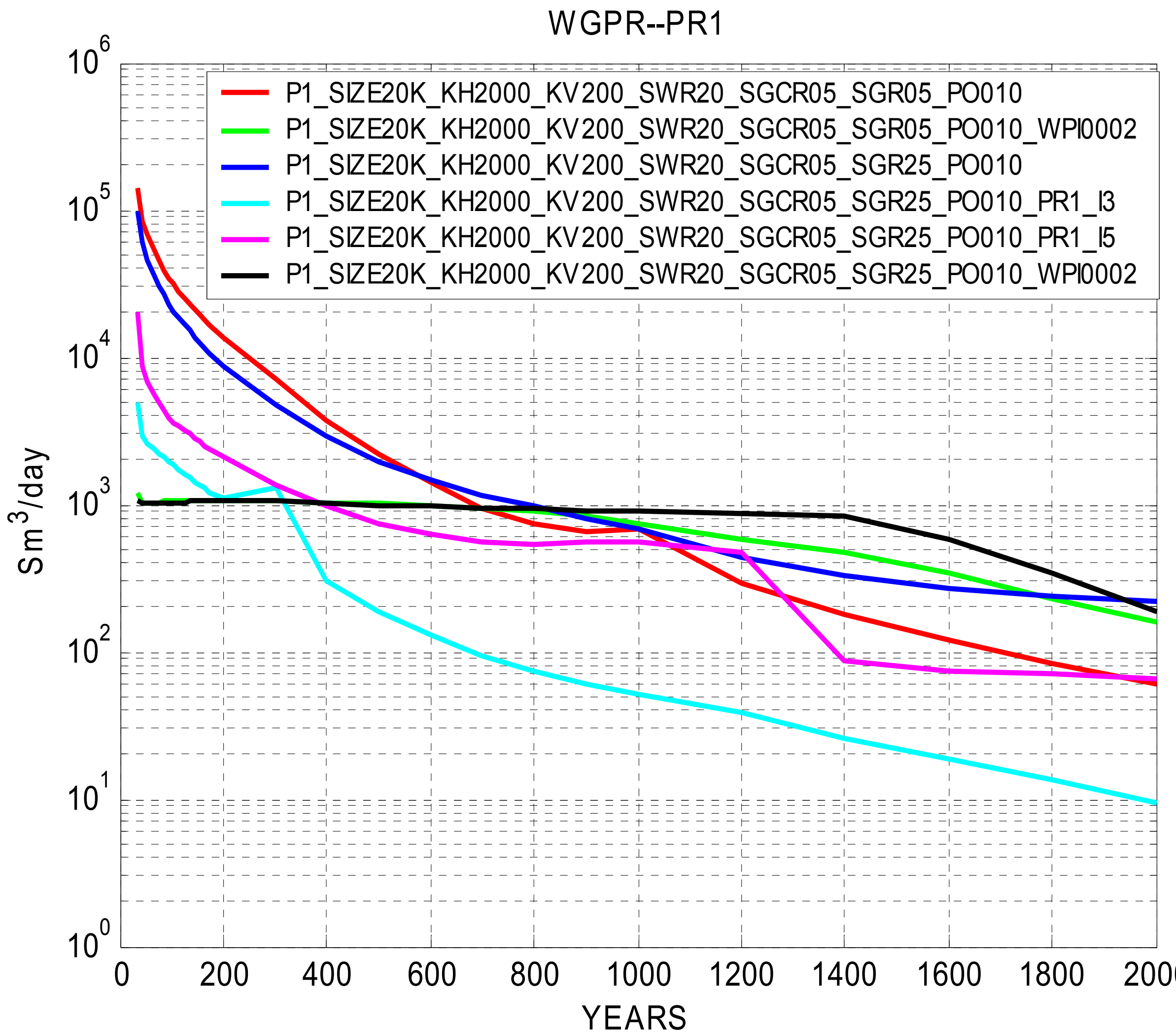


Leaking well modeling; *Well inflow parameter*

- By modifying the well inflow parameter (use WPIMULT in eclipse) the leakage rate can be adjusted. However, no predictions can be made from this since the modifications have not been connected to any reasonable physical model of the casing/cement corrosion process.
- A possibility is to adjust WPIMULT and see what value gives a certain maximum surface leakage rate, e.g. 1000 Sm3/d. Such a rate limit can e.g. be due to legal restrictions.
- For such a scenario the impact of different reservoir parameters may be studied.

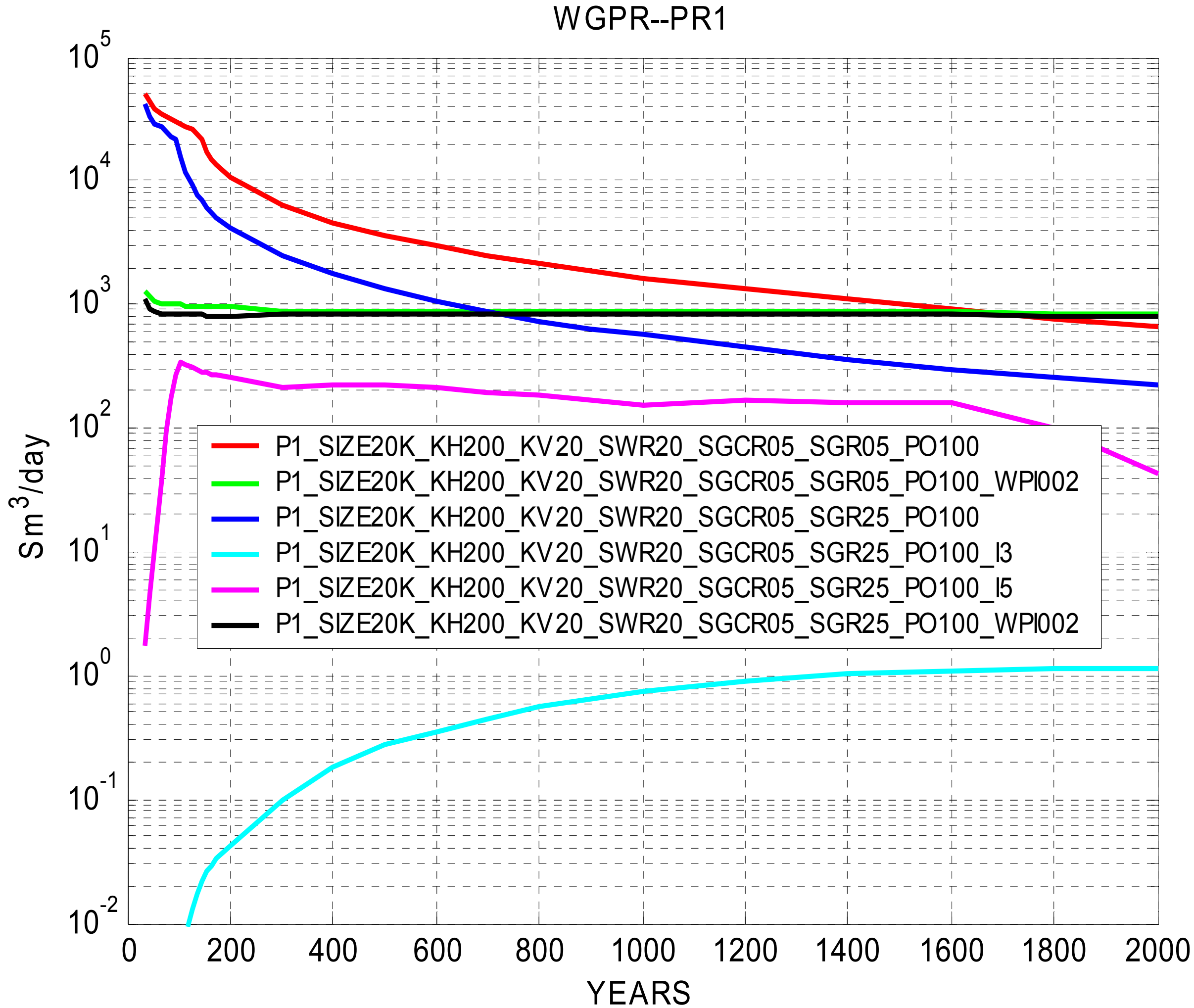
CO_2 leakage rate for (K_h,K_v)=(2000, 200) mD. Using WPIMULT = 0.002 gives a constant rate of 1000 Sm^3/d for almost 1400 years.

- The simulations ending with I3 and I5 correspond to the leaking well 2.1 km and 1.5 km from the injection point.

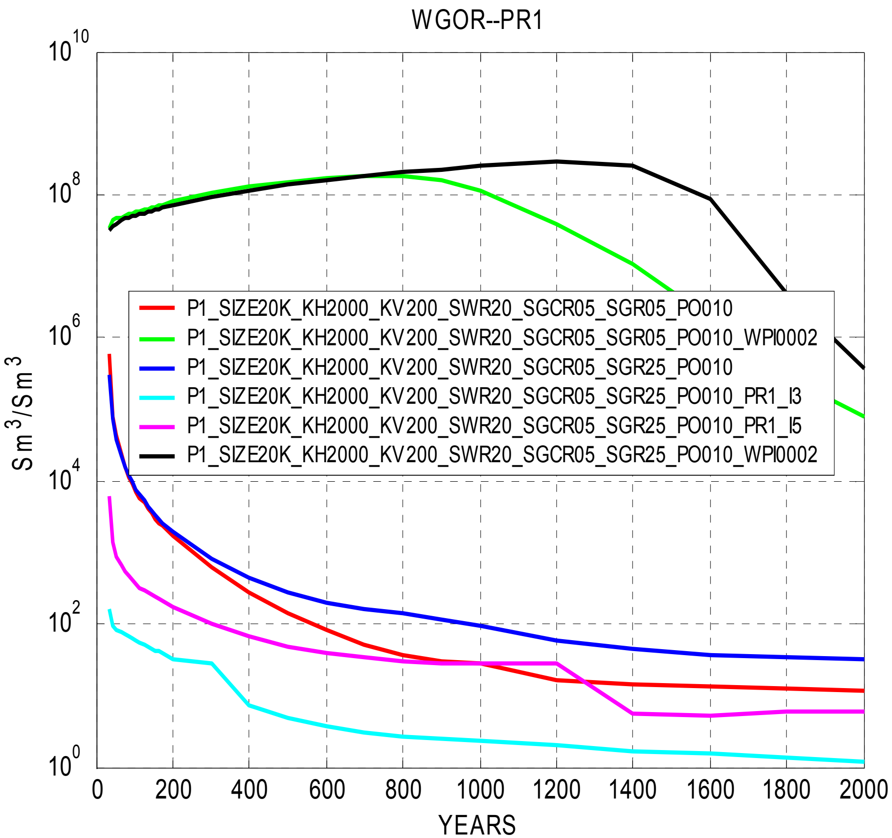


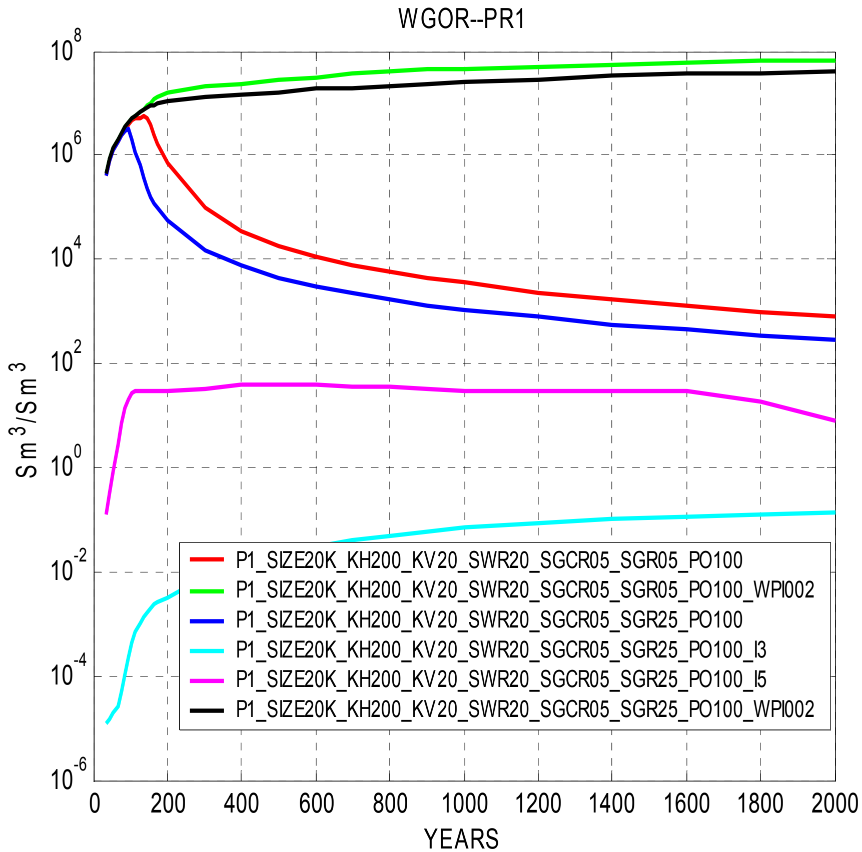
CO_2 leakage rate for (K_h,K_v)=(200, 20) mD. Using WPIMULT = 0.002 gives a constant rate of 1000 Sm^3/d for at least 2000 years

- The simulations ending with I3 and I5 correspond to the leaking well 2.1 km and 1.5 km from the injection point respectively.



GOR for the leaking well. A very high GOR is observed for WPIMULT = 0.002, GOR also decreases for increasing distance from the injection well.





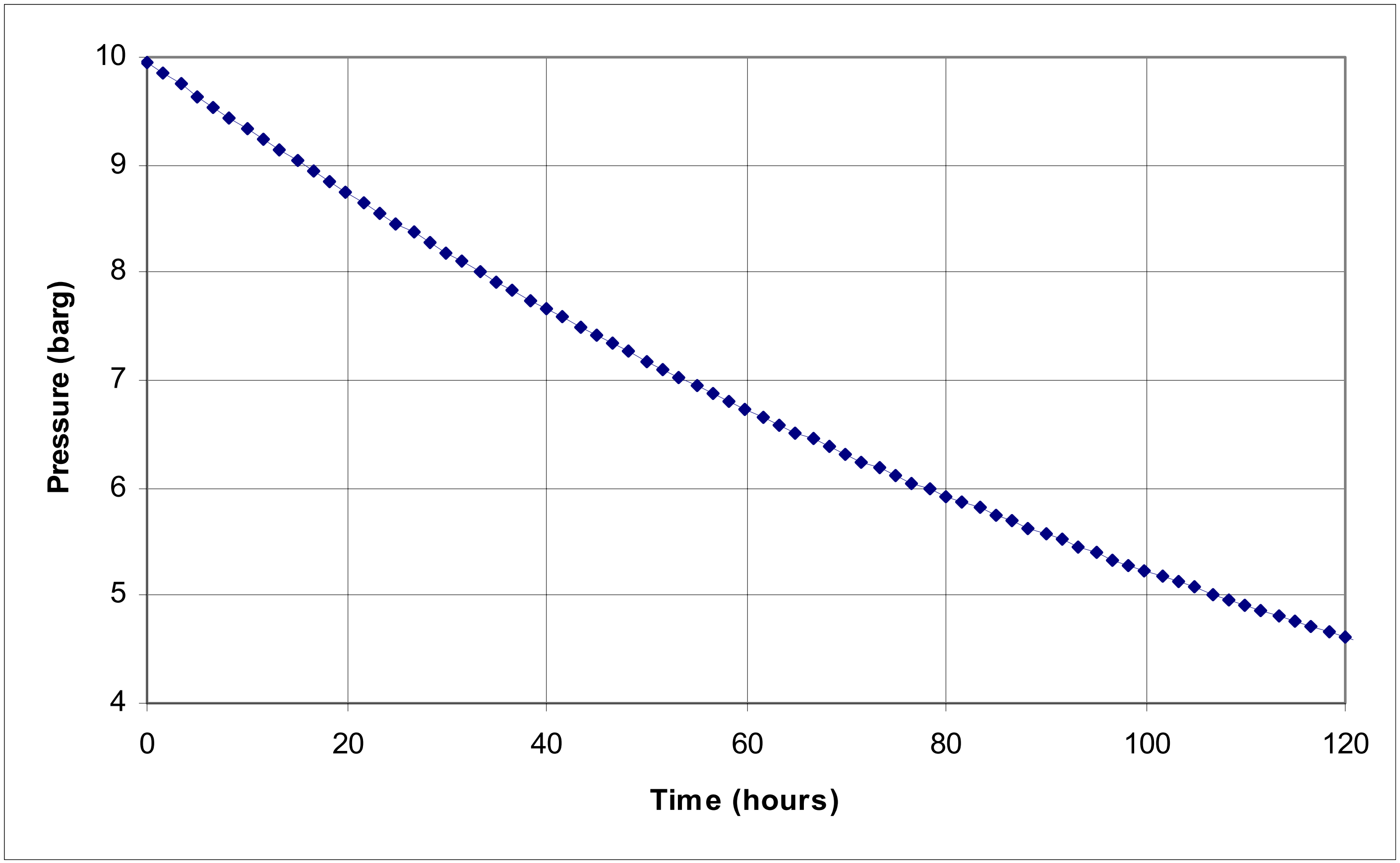
Conclusions on leaking well modeling

- A reservoir simulation model was established to estimate the risk of CO_2 escape from a leaky abandoned well and quantify the escape as an emission profile.
- The simulations have shown that an important factor regarding CO_2 escape from the reservoir is the erosion process of the cement in the well.

Permeability, porosity and weight before and after CO_2/brine exposure

- A slice of cured well cement was exposed to CO_2 and distilled water at a pressure of 300 bar and a temperature of 150 ^oC in a HPHT autoclave for four weeks.
- Klinkenberg corrected air permeability of dried cement core was determined by an unsteady-state (USS) or transient pressure falloff technique published by Jones, SPE 3535

Transient pressure falloff data points in fixed-volume gas tank at isothermal conditions during measurement



Conclusions on well cement permeability and porosity before and after CO_2 exposure

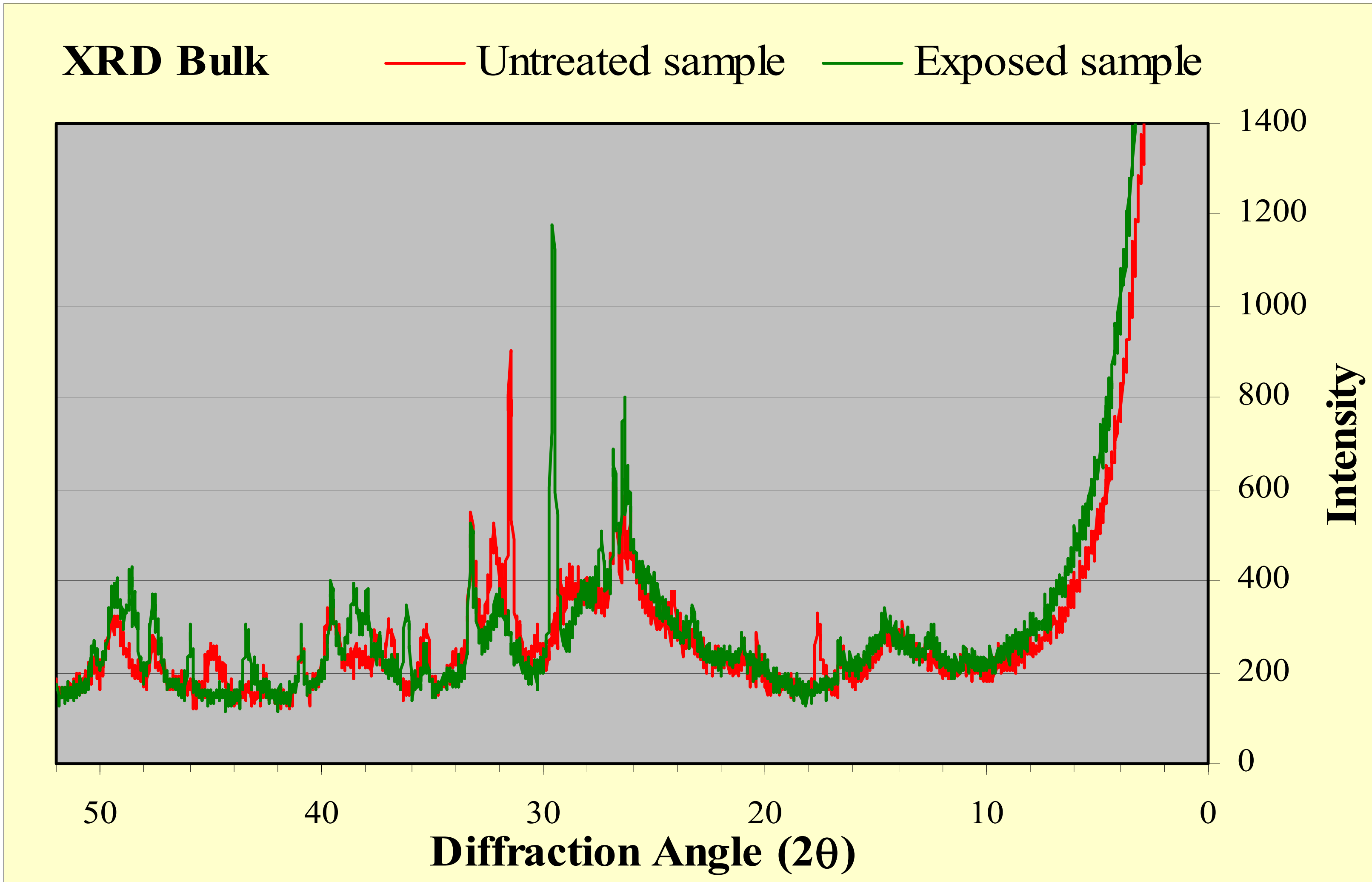
Parameter	Before CO_2 exposure	After CO_2 exposure
Out. diameter, mm	38.13	38.13
Length, mm	3.62	3.62
Weight 100 % water filled, g	8.03	8.09
Weight dry, g	6.646	6.441
Porosity, % of bulk volume	33.5	39.9
Klinkenberg corrected air permeability, m^2	2.3E-20	3.4E-20

SEM and XRD examination of concrete and the effect of highly corrosive, CO_2-enriched brine

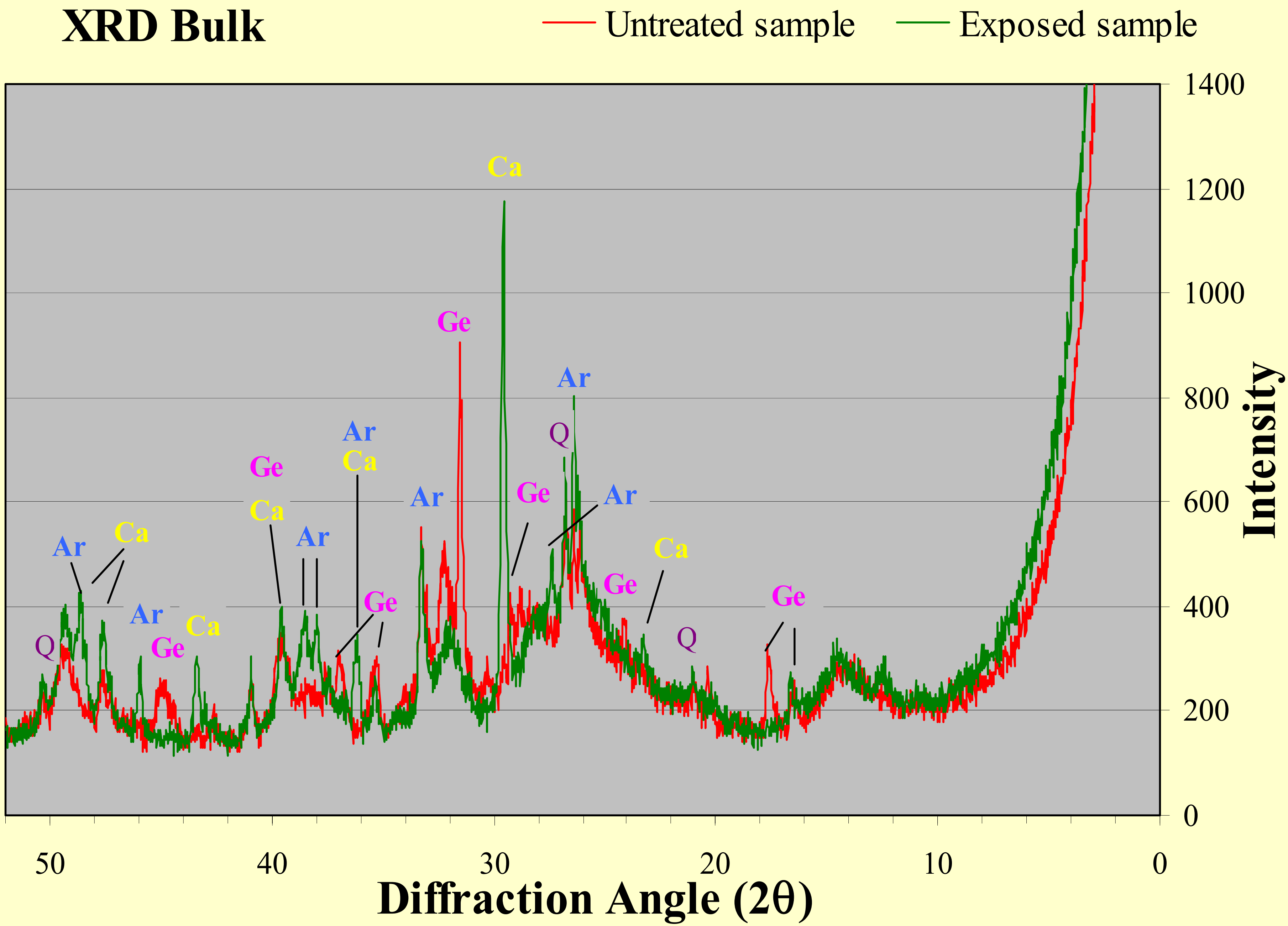
- Concrete (cement) treated with CO_2-enriched, reactive brine have been examined by scanning electron microscopy (SEM) and X-ray diffraction analysis (XRD).

- In order to enable identification of changes that might occur during exposure to the reactive brine also untreated sample was examined.

X-ray diffractograms of the cured well cement before and after exposure to CO_2-enriched brine. Some minerals disappeared, others are formed



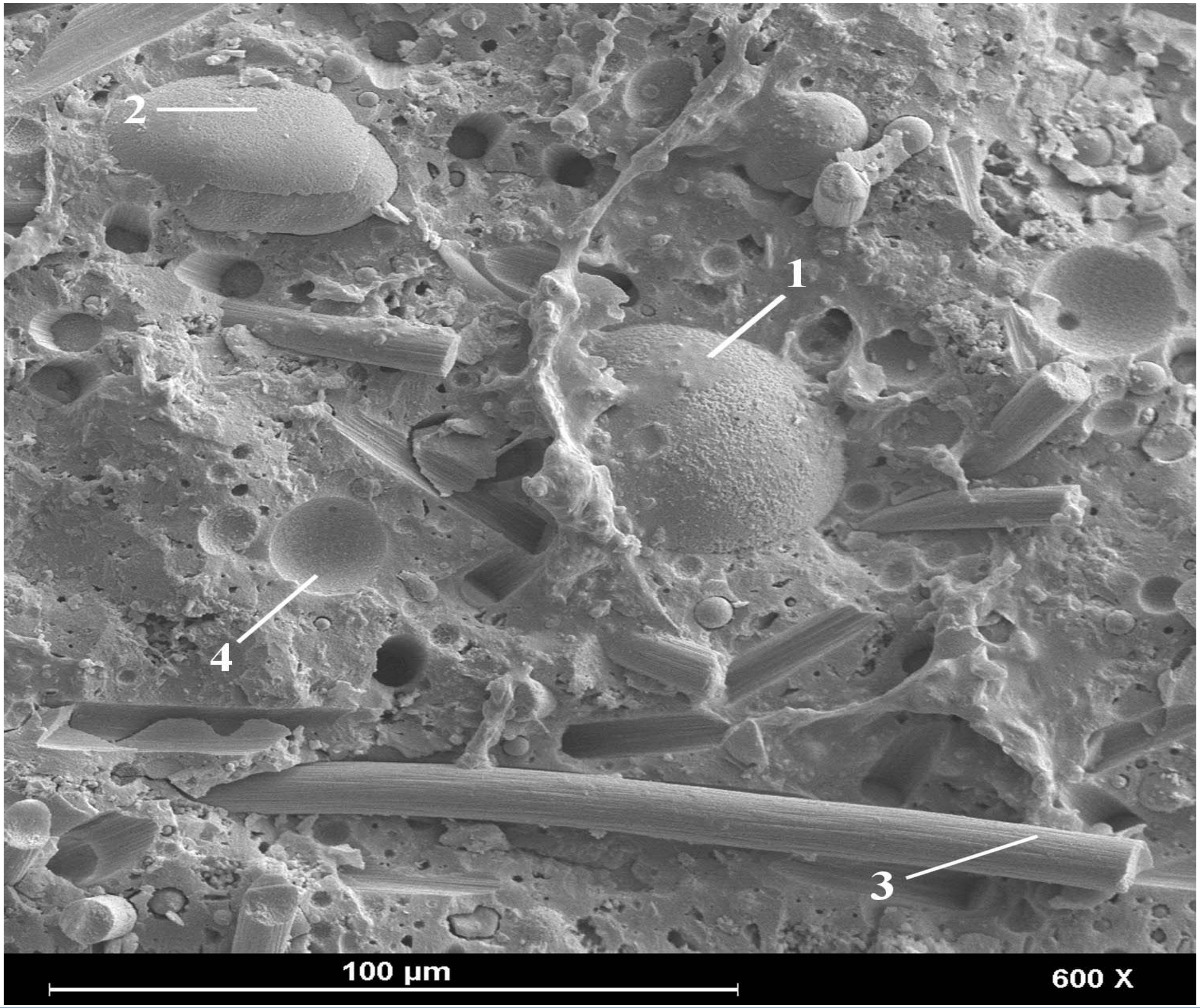
XRD Bulk


Untreated sample
Exposed sample
Ca
Ge
Ar
Q
Ar
Ca
Ge
Ar
Ge
Ca
Ar
Ca
Ar
Ca
Ar
Ca
Ar
Ge
Ca
Ge
Ge
Q
Ar
Ge
Ca
Q
Ge
1400
1200
1000
800
600
400
200
0
50
40
30
20
10
0
Intensity
Diffraction Angle (2θ)

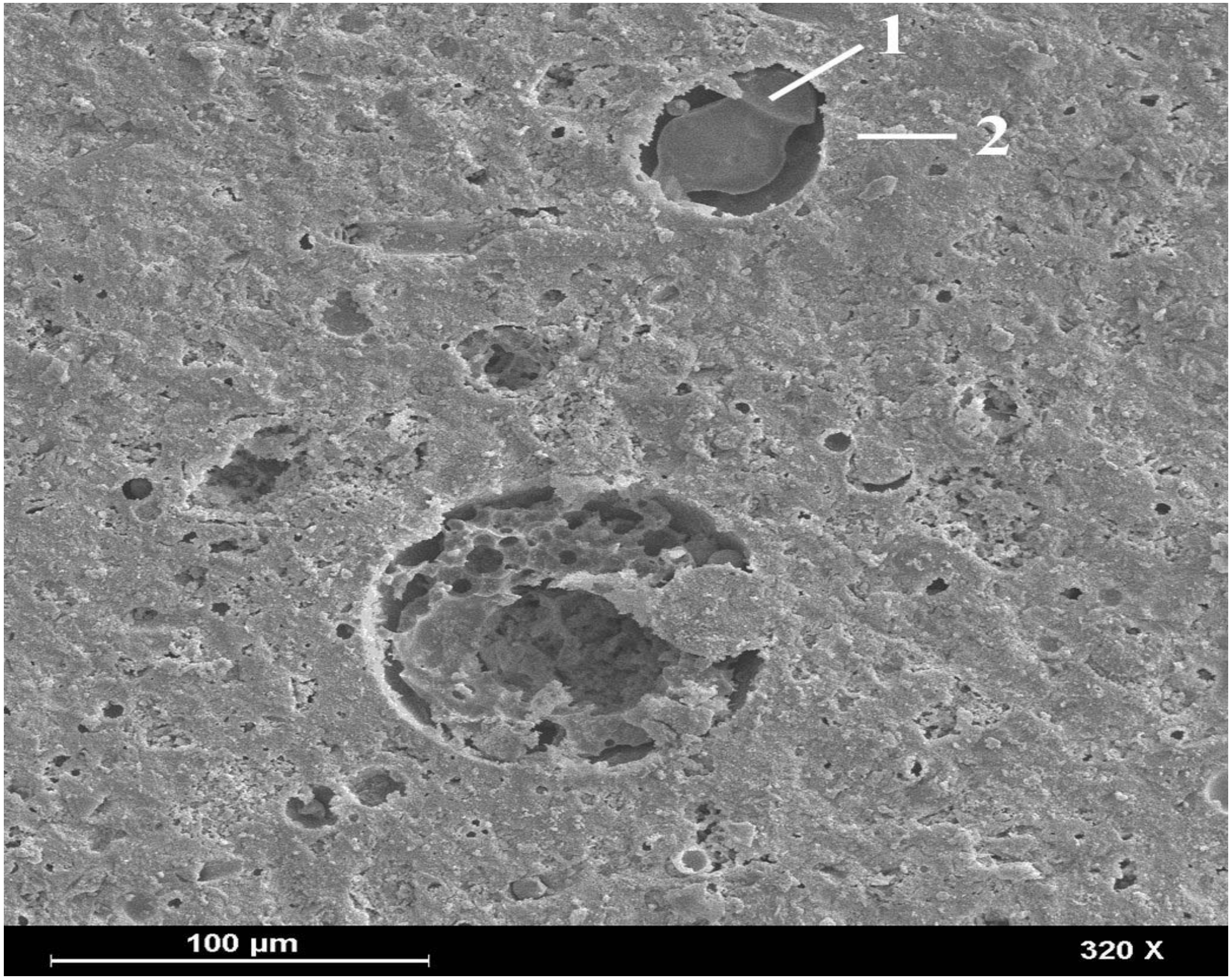
Results X-ray diffractograms before and after CO_2/brine exposure

- The X-ray diffractograms of untreated and exposed samples revealed that crystalline phases disappeared and new were formed.
- The mineral gehlenite ($Ca_2Al_2Si_2O_7$) can account for many of the peaks that disappeared.
- Calcite and aragonite ($CaCO_3$ polymorphs) can explain many of the peaks that appeared after the reaction with the brine. However, some peaks remained un-identified.

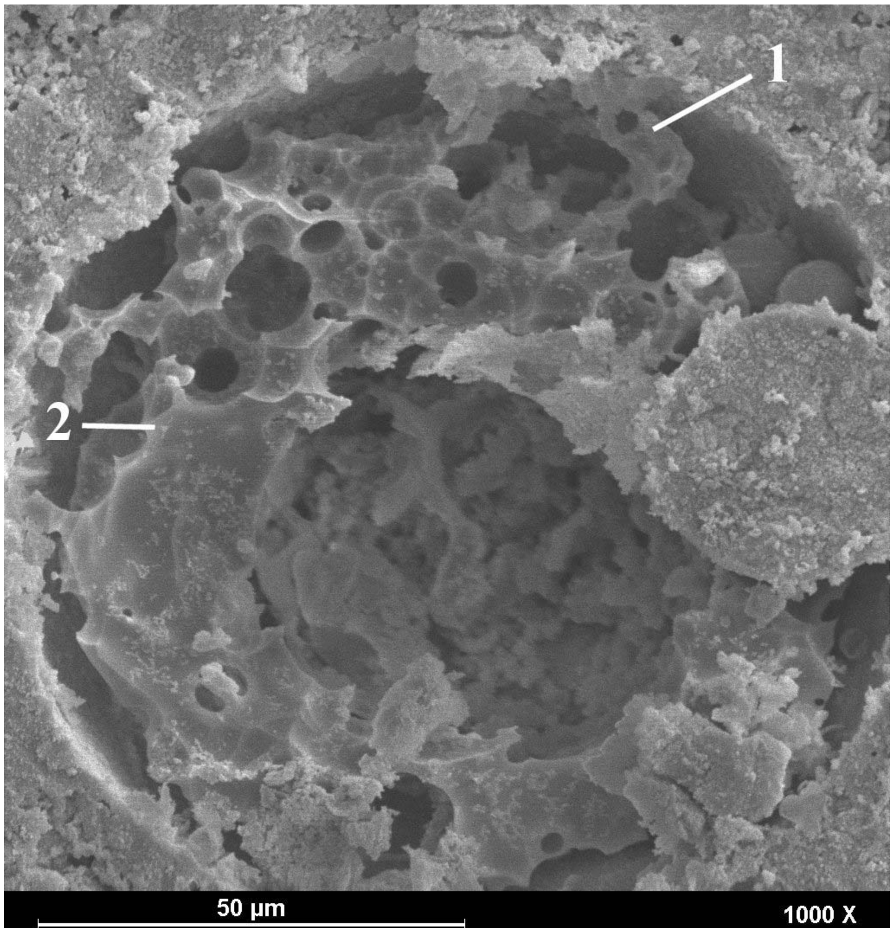
Close-up from SEM overview image. The numbers indicate the positions from where the EDS element distribution was acquired (100 microm scale).

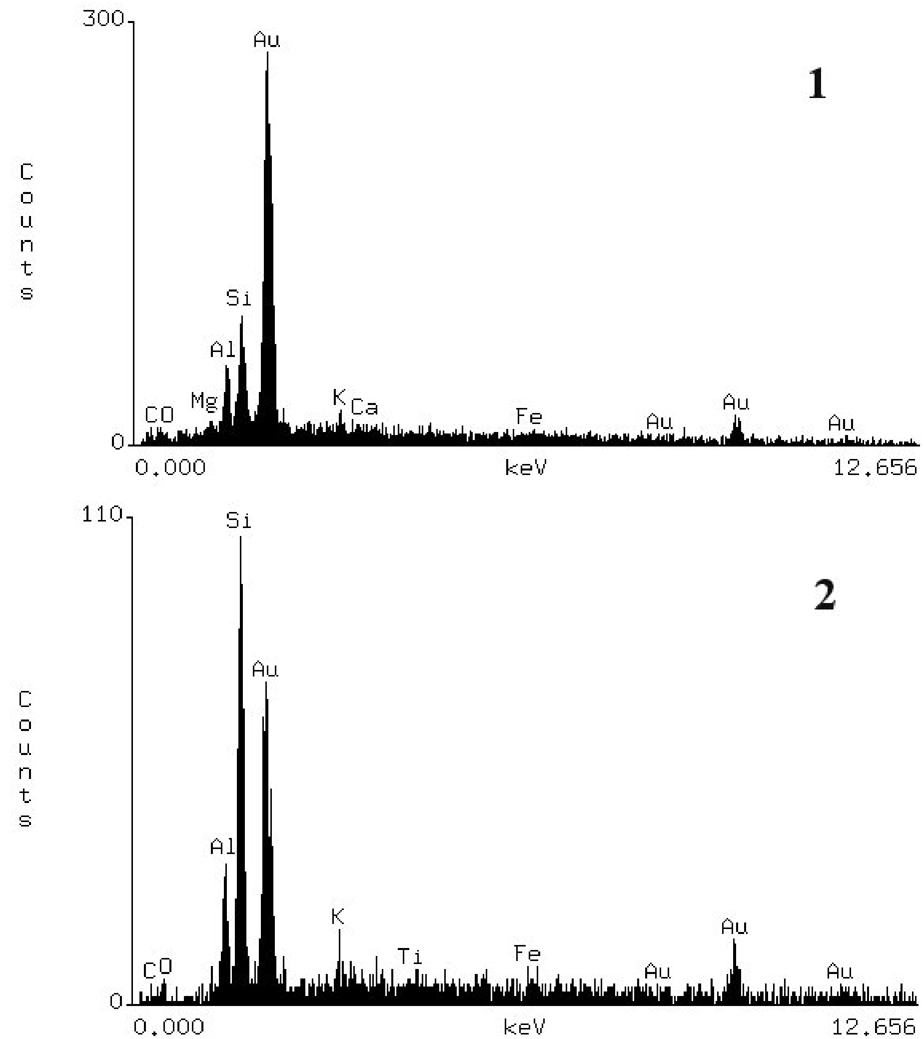


Overview secondary electron image from the disc surface of the well cement that has been exposed to highly CO_2/brine.

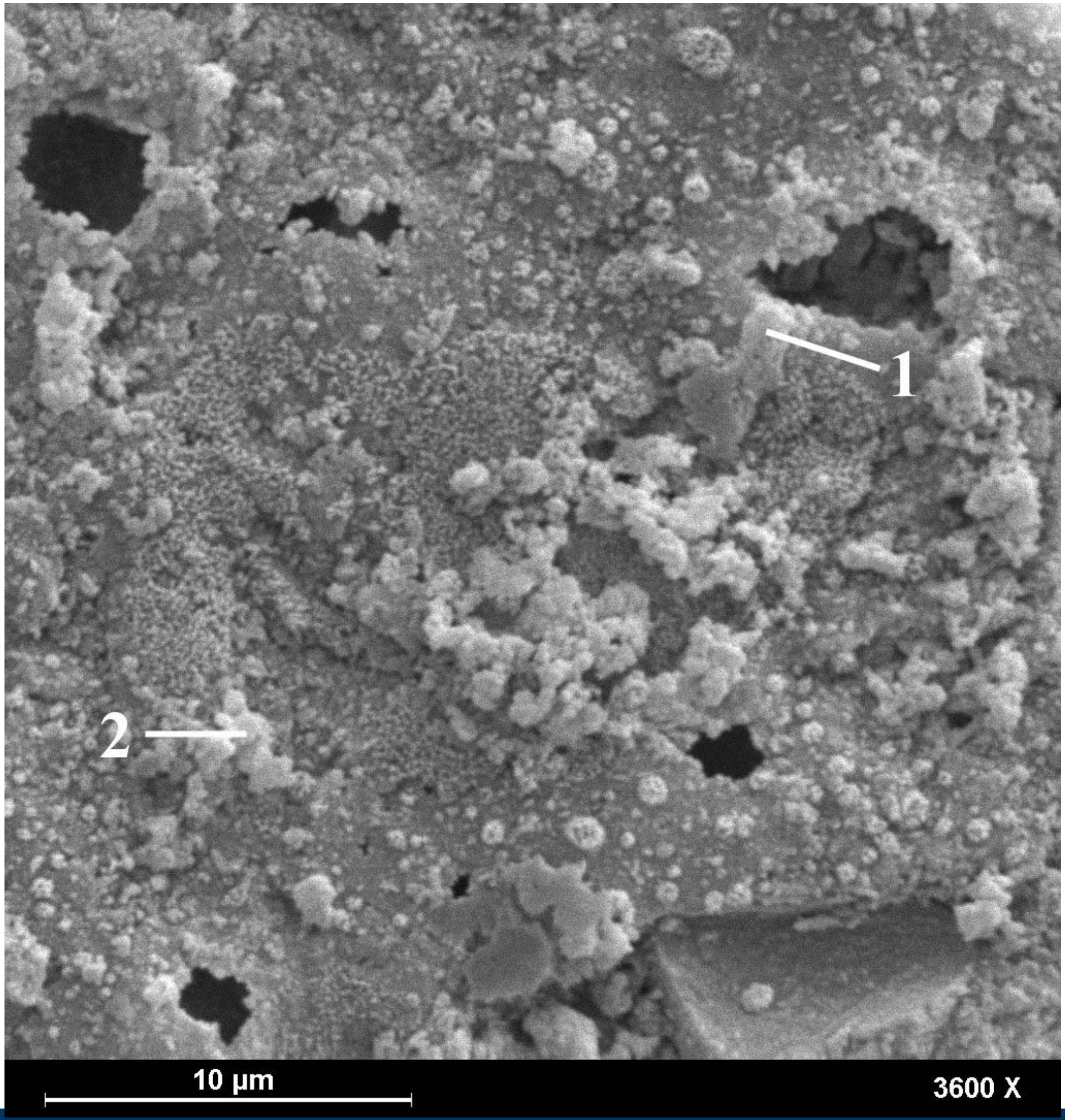


Close-up from previous slide demonstrating that extensive dissolution of a spherical body has taken place (50 microm scale).

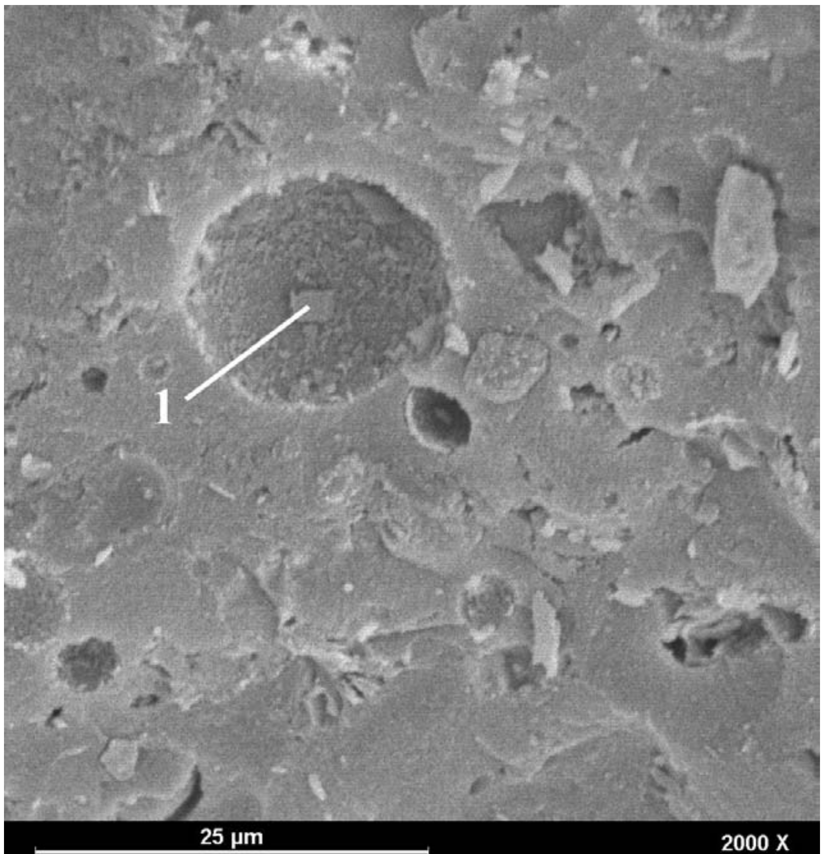


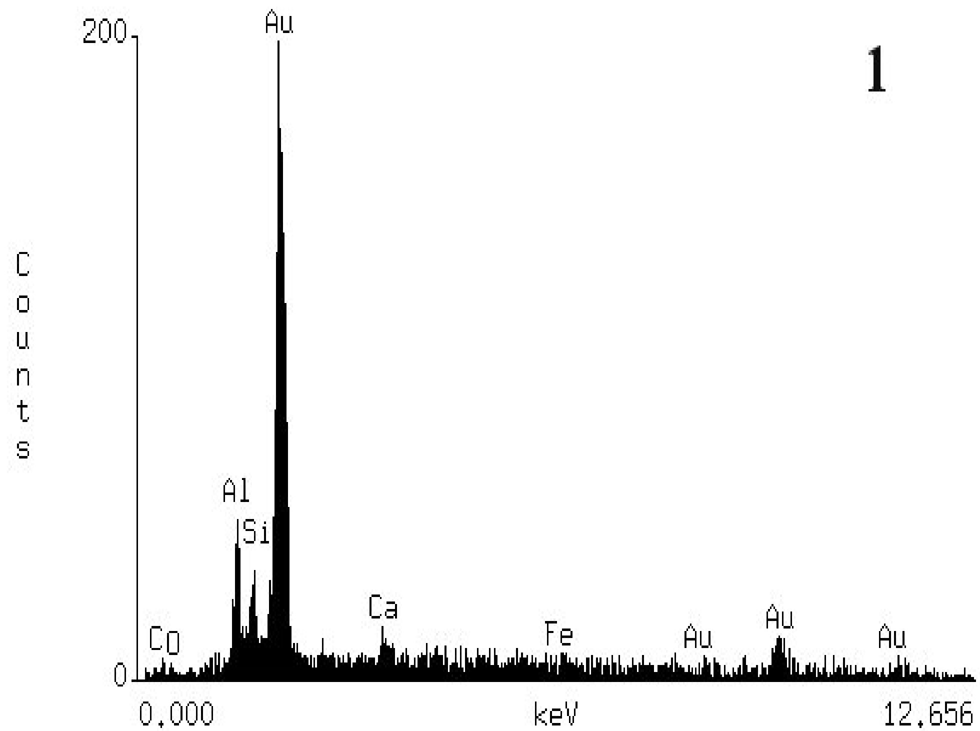


Close-up from previous slide demonstrating that extensive dissolution of a spherical body has taken place (10 microm scale)



Close-up from the previous image showing a precipitate (point 1) in a spherical pore (25 microm scale). EDS diagram showing the element distribution in point 1 in Figure at left. Al, Si and Ca represent the main elements of the crystal.

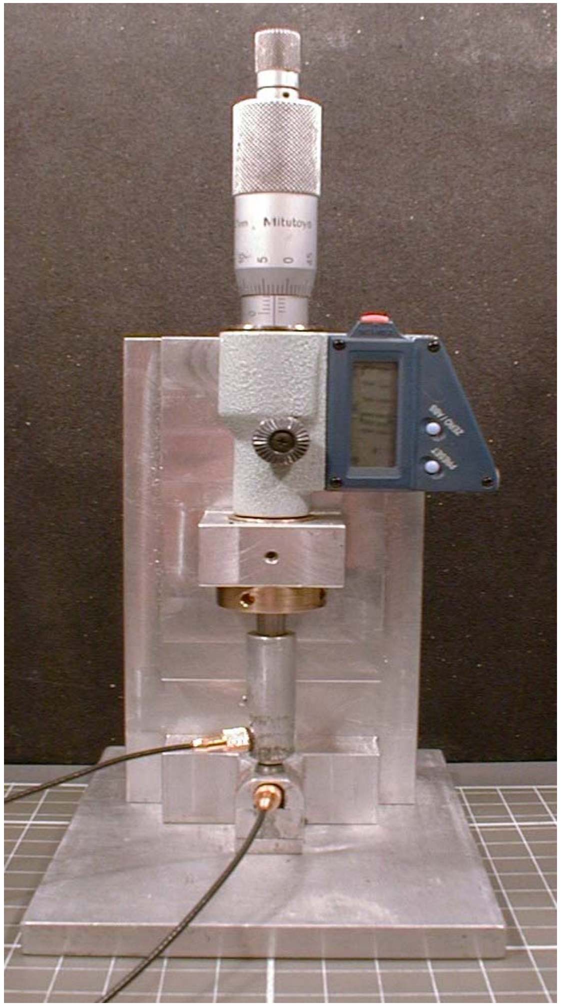




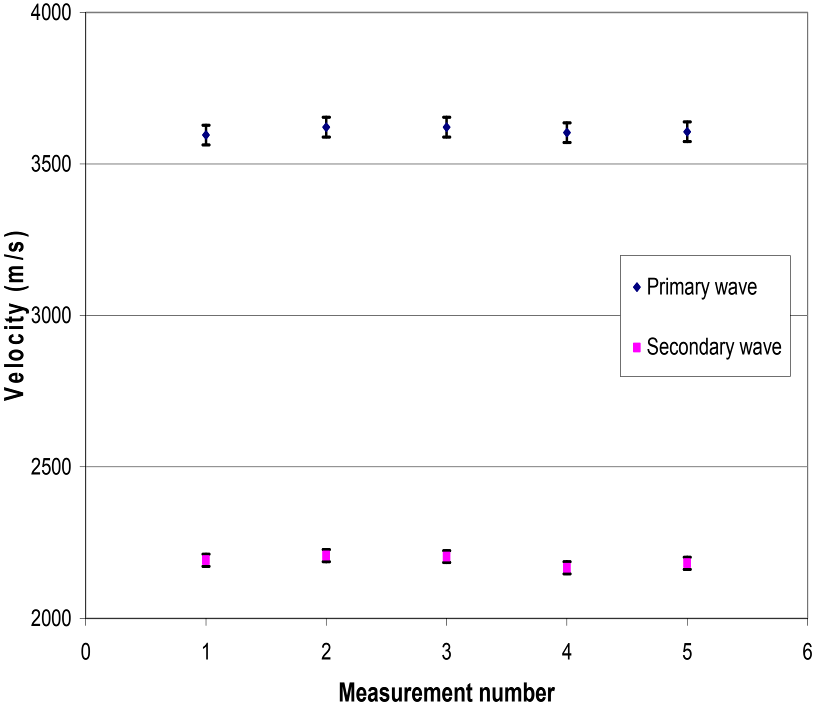
Conclusions on SEM and XRD examination of concrete and the effect of highly corrosive, CO2-enriched brine

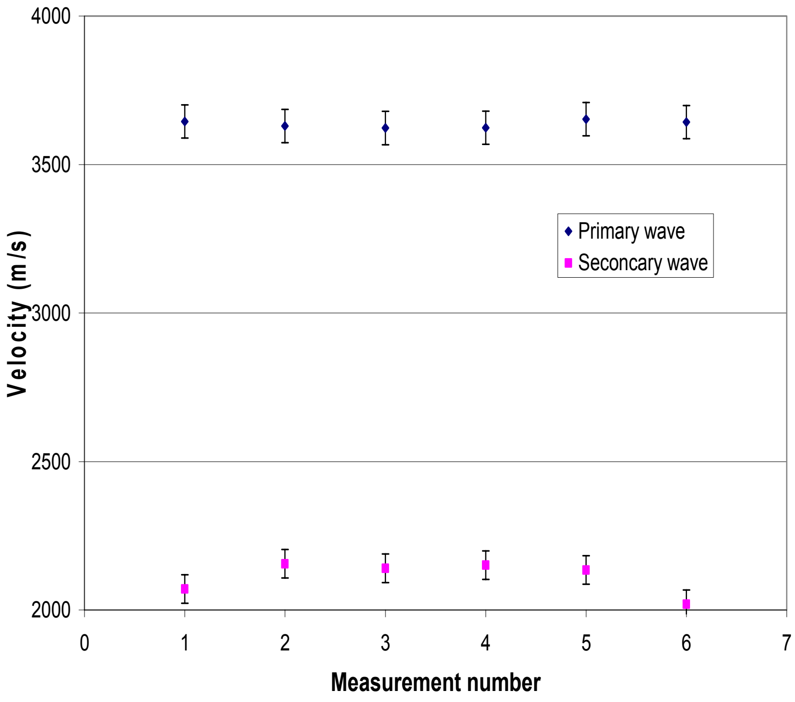
- SEM visualisation images revealed that dissolution of spherical bodies had taken place close to the sample surface, but minor corrosion was also indicated on spherical bodies inside the sample. Any distinct dissolution of the matrix was not observed.
- However, crystalline matter has been precipitated both on the sample surface and in pores inside the sample. The largest crystals in the precipitate mainly consist of Al, Si and Ca. Calcite and aragonite were not identified by SEM, and probably they exist as finer crystal aggregates beyond resolution.
- Nevertheless, the SEM analysis verified the result from the XRD analysis: both dissolution and precipitation have taken place during exposure.

Primary and secondary wave velocities have been measured by CWT (Continuous Wave Technique)



CWT Measurement Results before and after CO_2/brine exposure



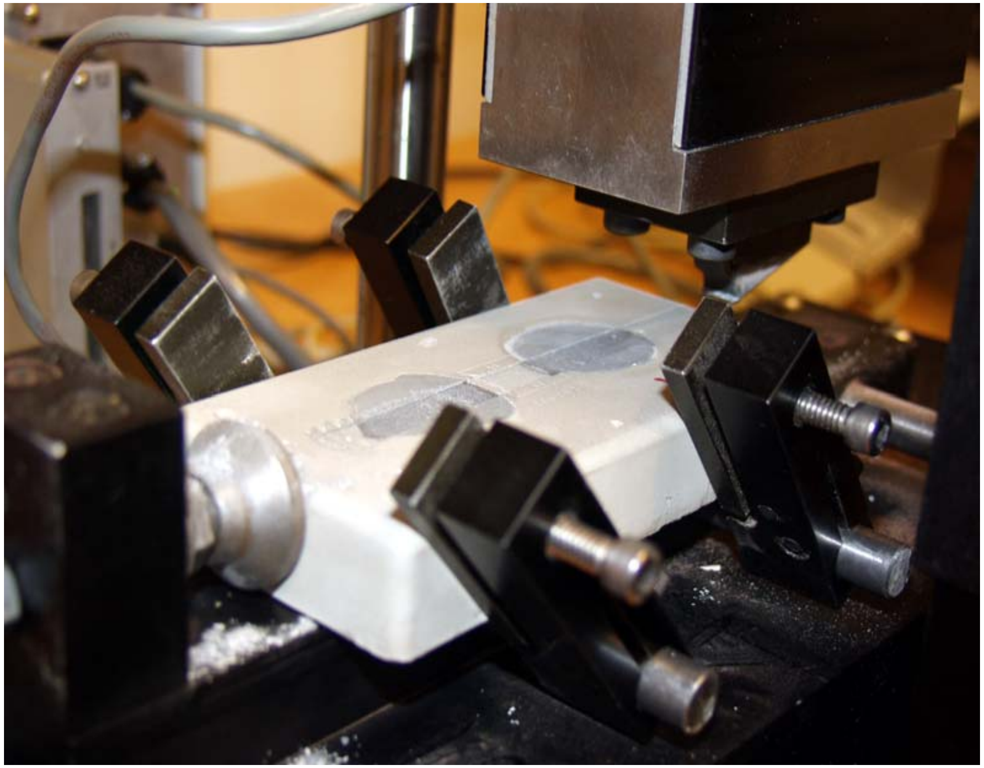


Conclusions CWT measurement

- The behaviour of the velocities does not indicate any big changes.
- The small increase in P wave velocity is probably only the result of the decreasing in density, due to the increasing in the porosity.
- The cement elastic bulk modulus (K) is not strongly affected from porosity increase. A decrease of K equal to 1.4% has been computed for an increase in porosity equal to 6%.

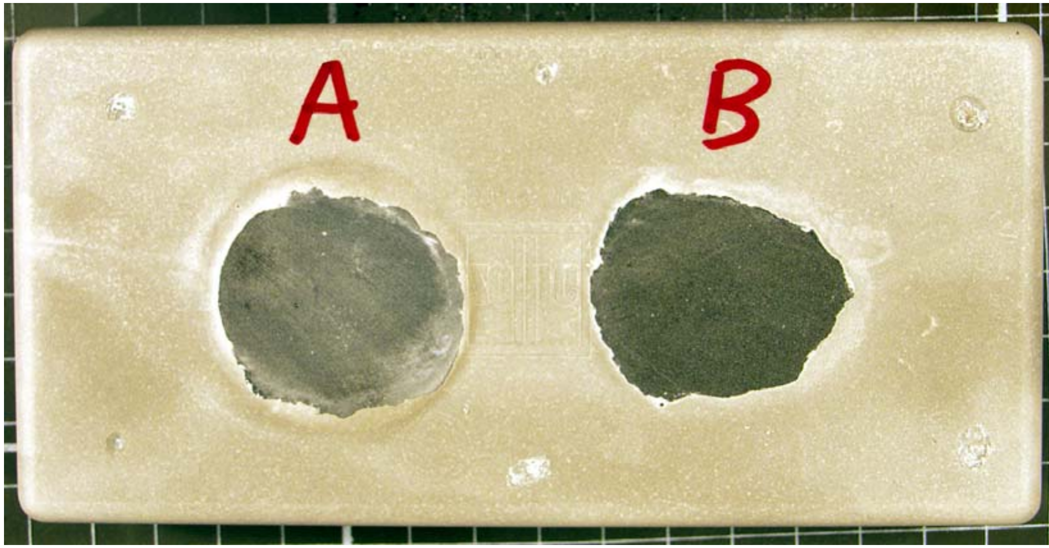
Mechanical parameters from Scratch tests on well cement disks

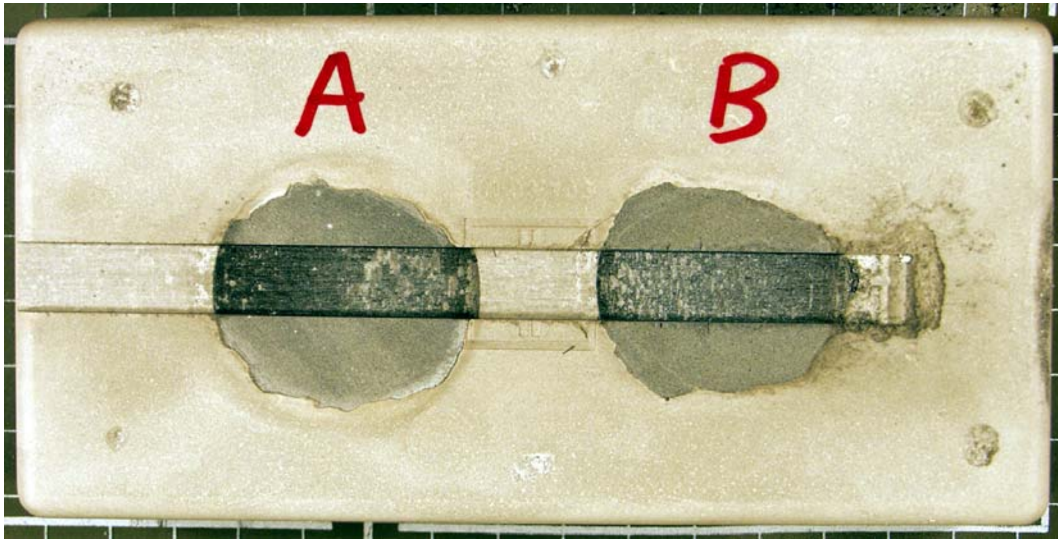
- The scratch equipment cuts a 10 mm wide groove in the surface and measure vertical and the horizontal force parallel to the direction of cut.
- From the average horizontal force and the depth of cut is the specific energy calculated which correlates with the unconfined compressive strength of the material.
- The cut depths used on the cement disks are between 0.07 and 0.29 mm.



Mechanical parameters from Scratch tests on well cement disks

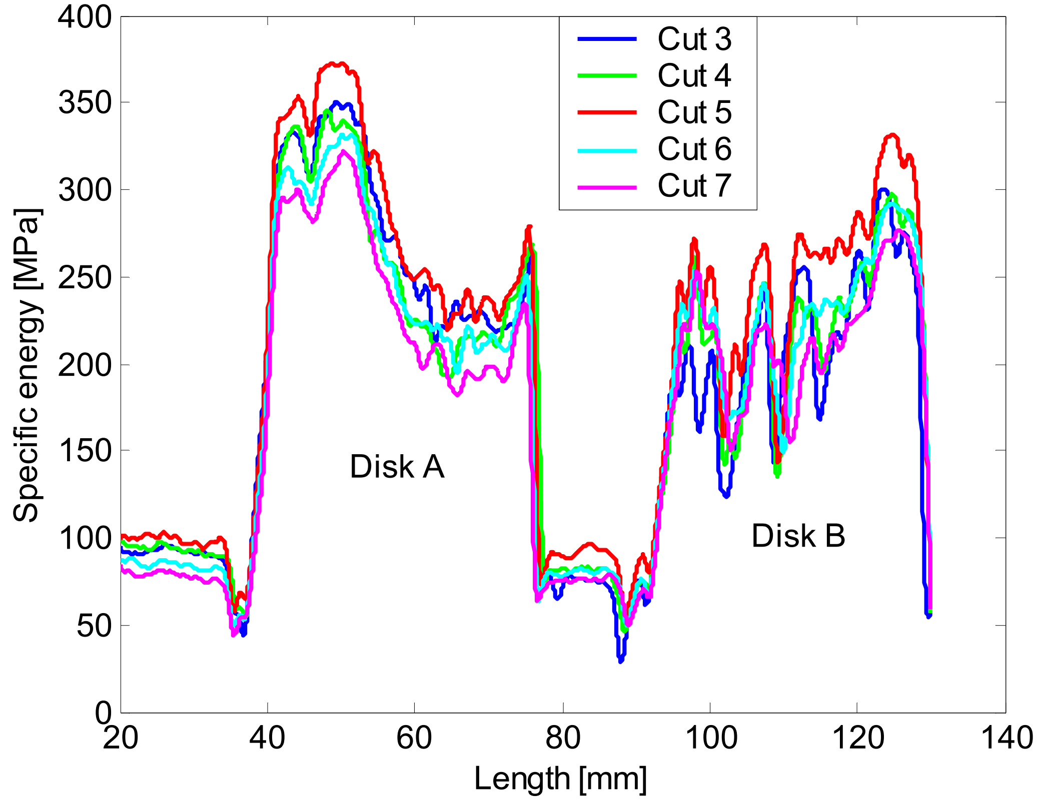
- Two disks with a diameter of 1.5” and thickness of ~0.25” were put in cement in order to perform the scratch tests.
- Disk A is unexposed and disk B is exposed to CO_2/brine.
- Note the variation in the smoothness of the groove inside one disk. This indicates that the mechanical properties is not homogeneously distributed in the cement.



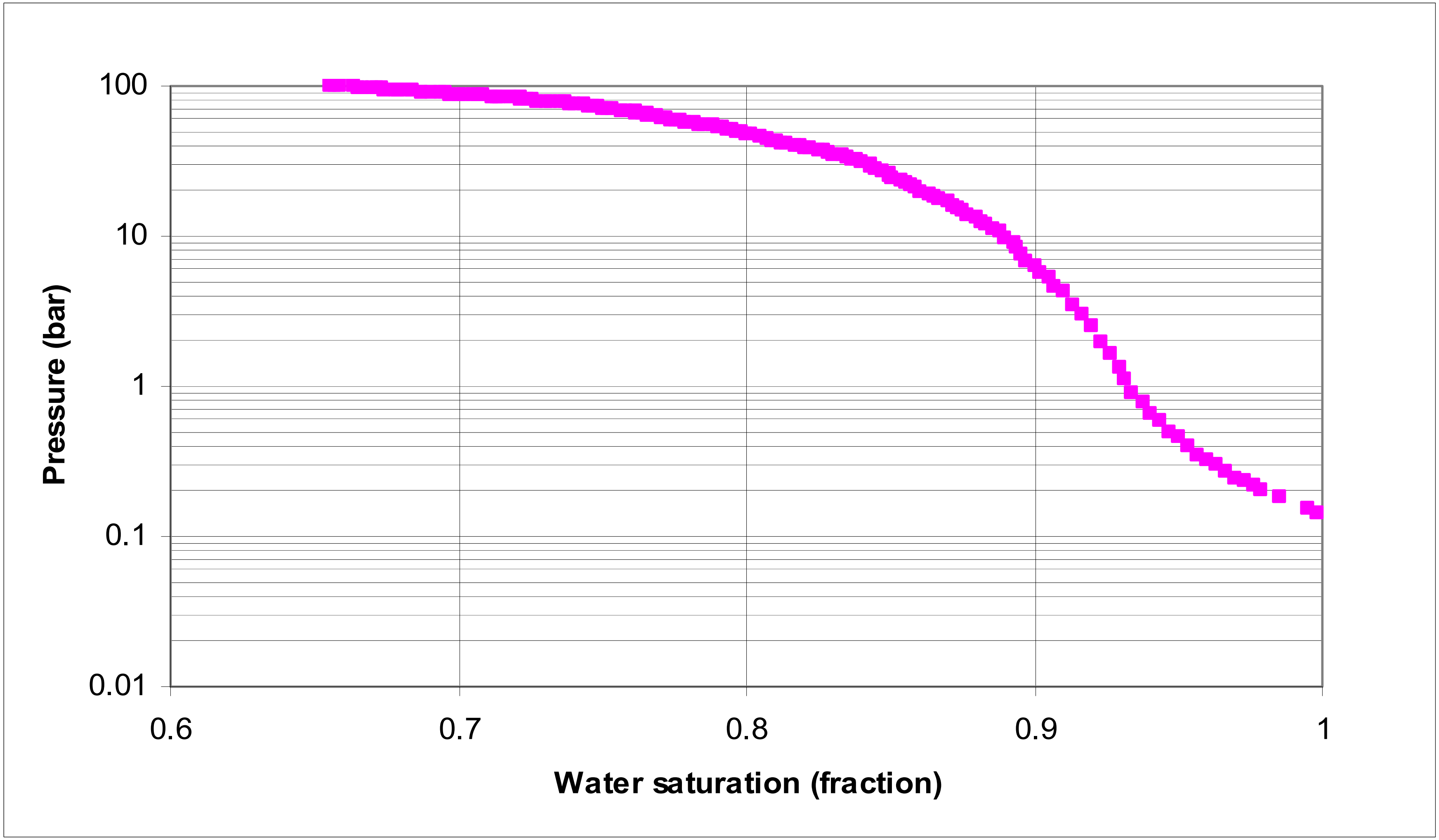


Scratch test on cement disks: Results

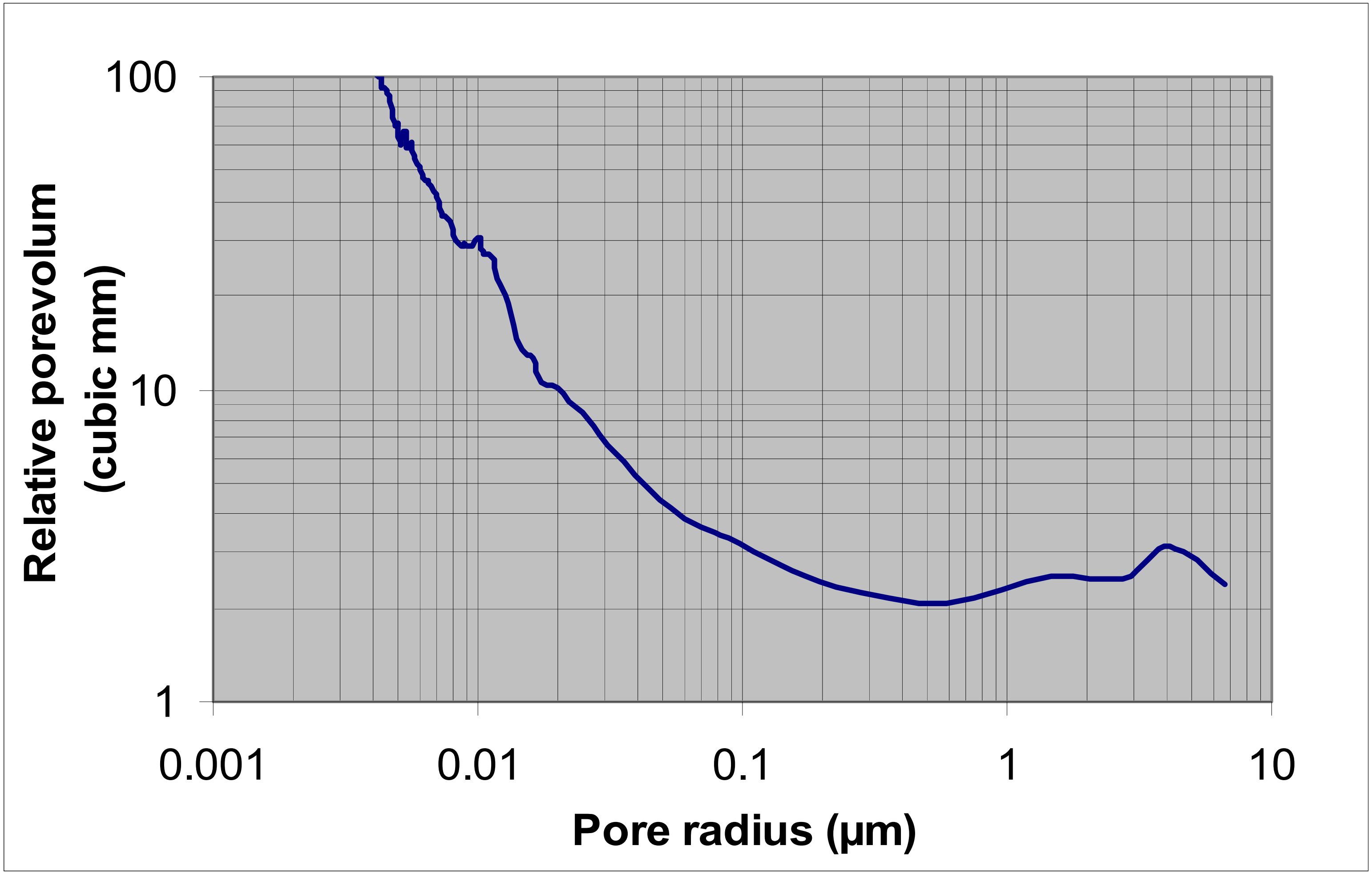
- The mechanical properties seem not to change with exposure to CO_2/brine.
- The specific energy measured with ~0.1 mm deep cuts from 0.2-0.7 mm depth from the surface do not show any significant changes with depth in any of the disks.
- The difference in specific energy is larger within the unexposed sample than in the exposed sample indicating inhomogeneous strength distribution in the cement.



CO2-water capillary pressure of cured cement sample (Hg injection, IFT scaled).



Pore size distribution of cured cement sample determined by Hg-injection



Conclusions on CO_2 capillary entry pressure into cured well cement

- The capillary entry pressure (P_e) of CO_2 to enter into the water saturated cured cement sample is 140 mbar.
- The P_e of CO_2 to enter into the water saturated well cement and did not change after being exposed to CO_2 and distilled water at a pressure of 300 bar and a temperature of 150 ^oC in a high-pressure autoclave for four weeks.

CO_2 corrosion of Portland cement

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

The causes of CVF's as recognised by the industry and well documented are

- Poor mud displacement and poor cleanup of pipe and formation surface in the primary cement placement.
- Cement shrinkage under down-hole conditions in particular during primary cementing.
- Cement sheath failure, resulting in sheath cracking
- Gas migration through the setting cement creating gas channels in the set cement.
- High cement matrix permeability

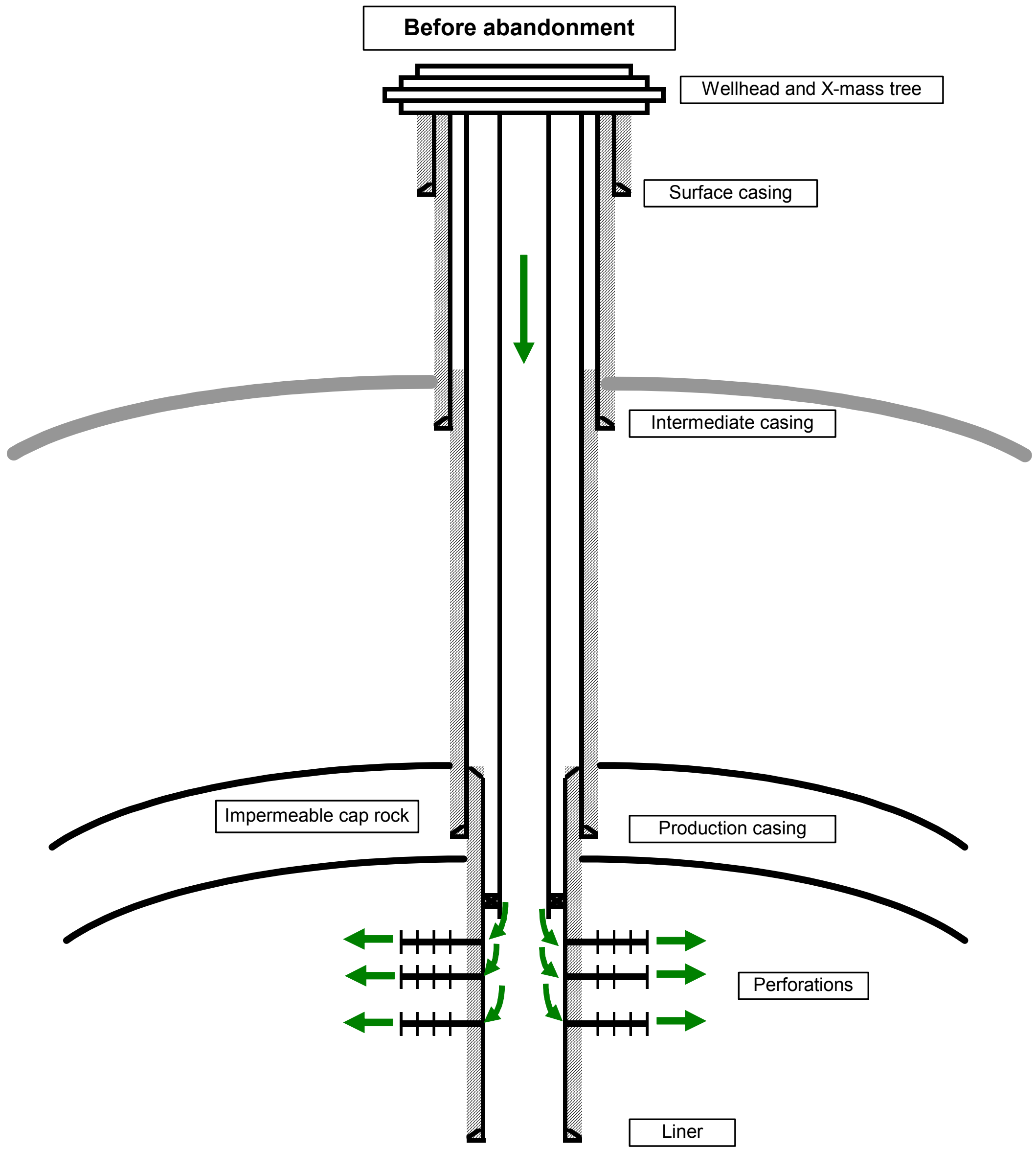
CO_2-storage: reference projects

- Active since 1987 with several North Sea projects
- European ”CO_2 Underground disposal” assessment (JOULE II, 1993-1996)
- ”Saline Aquifer CO_2 Storage” (SACS) project (EU-funded study of CO_2-storage in Sleipner field, 1997-2002)
- Simulation of miscible injection at Gullfaks field (2001)
- Feasibility study on a national CO_2-infrastructure for large scale CO_2-EOR and deposition (2002-2003)
- Study of corrosion effects on concrete & steel in wells (Carbon Capture project, CCP, 2002-2003)
- CO2STORE (EU-funded study of CO_2-storage 2002-2005)
- Norwegian competence building project on CO_2-EOR and storage (national & industry funding, 2002-2005)
- CCP1-2 (JIP-funded study on aquifer CO_2 storage and sealing capacity of cemented petroleum wells 2003-2005)
- CASTOR (EU-funded study on capture and storage, 2004-2007)

CO_2 injection well before abandonment (schematic)

- A general statement is that construction of new CO_2 injection wells should preferably be placed at the flank of a storage anticline.
- Special care should be taken when constructing these wells;
- Set production casing in the middle of cap rock
- Minimize liner overlap length
- Use high specialized cement and casing materials

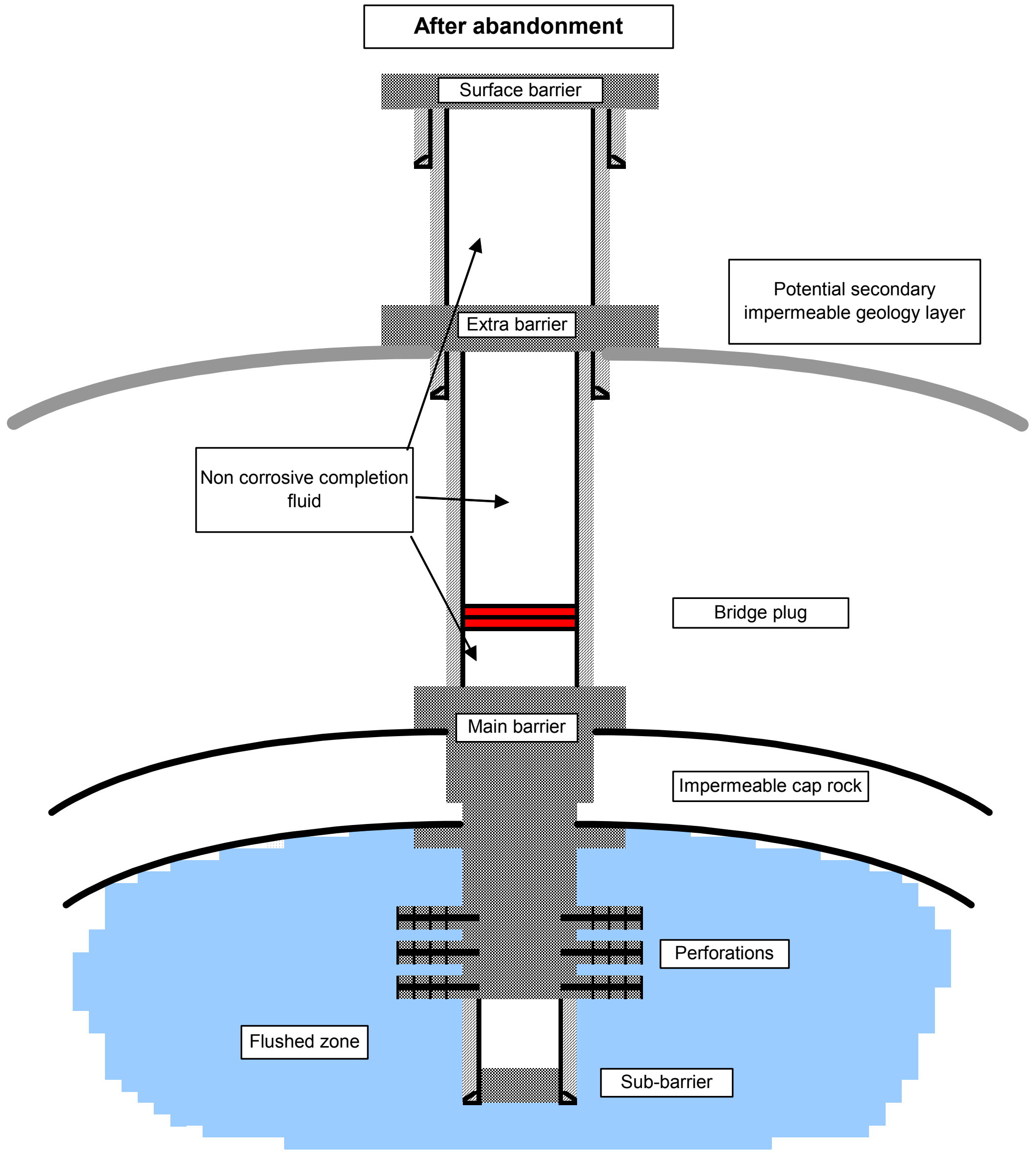
CO2 storage well before abandonment (SINTEF)



Operational procedures for safe CO_2 well abandonment

1. Remove tubing and packer
2. Set cement plug at the bottom of the well (sub-barrier)
3. Mill out casing from liner lap to end of perforations
4. Inject cement in perforations and cement the open hole interval
5. Squeeze cement in the lower and upper cap rock formation
6. Set mechanical bridge plug
7. Remove upper free-cement casing
8. Mill out intermediate casing and squeeze cement
9. Remove wellhead and mill out surface casings and squeeze cement

CO2 storage well after abandonment (SINTEF)



Testing of CO_2 resistant material for Well Integrity under wet carbon dioxide supercritical environment

V.Barlet-Gouédard (Schlumberger)

B.Goffé & G.Rimmelé (CNRS/ENS - France)

CENTRE NATIONAL DE LA RECHERCHE SCIENTIFIQUE

Schlumberger

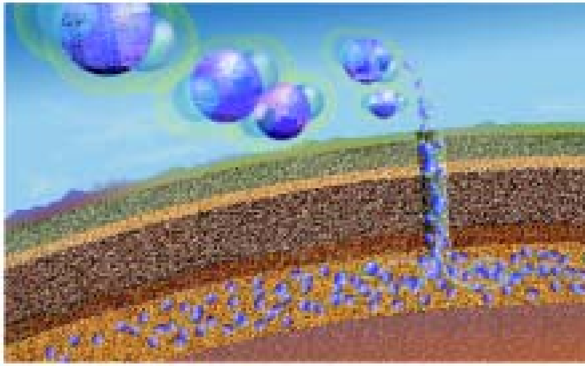
IEA-WI, 2005

VGB, BG, GR

Concerns and Approach

Motivation

- Well integrity identified as the largest risk from Analogues
  - Portland cement not thermodynamically stable in CO_2 environments
    - Failure of the cement
    - Long-duration isolation and integrity for CO_2 wells (thousands of years)
- Poorly addressed by Current Standards



Approach

- Towards a standard lab equipment to test the new material in presence of CO_2 as wet supercritical fluid and as dissolved in water
- Develop standard accelerated procedure/method to assess its long term durability
- Develop and test cement formulations that withstand mid to long term exposure

Issues

- Does Conventional Testing simulate Actual Conditions?
- What need to be measured for qualify and quantify the carbonatation process?
- How does the carbonatation of Portland cement proceed under supercritical wet CO_2 ?

An experimental approach

Reactions of Portland Cement Hydrates with CO_2

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

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

$$\text{C-S-H phase} + H^+ + HCO_3^- \longrightarrow CaCO_3 + \text{amorphous silica gel}$$

$$CO_2 + H_2O + CaCO_3 \longrightarrow Ca(HCO_3)_2$$

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

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Does Conventional Testing simulate Actual Conditions ?

Carbonatation using a Na_2CO_3 or $NaHCO_3$ solution (4%) with the reaction :

$$Ca(OH)_2 + Na_2CO_3 \rightleftarrows CaCO_3 + 2\,Na(OH)$$

Experiments on neat Portland cement core samples at 90°C-280 bars - one month in Na_2CO_3 solution (4%):

Very limited carbonatation effects mainly expressed by the pH increasing of the solution from 6.5 to 13

This procedure doesn't reproduce the acidic conditions of a CO_2 rich environment and is not realistic

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Wet supercritical CO_2 experimental reactors

TAV Reactor

(Titanium Annular Vessel)

TSCV Reactor

(Titanium Simple Cylinder Vessel)

0 < P < 500 bar
0 < T < 150°C

0 < P < 500 bar
0 < T < 350°C

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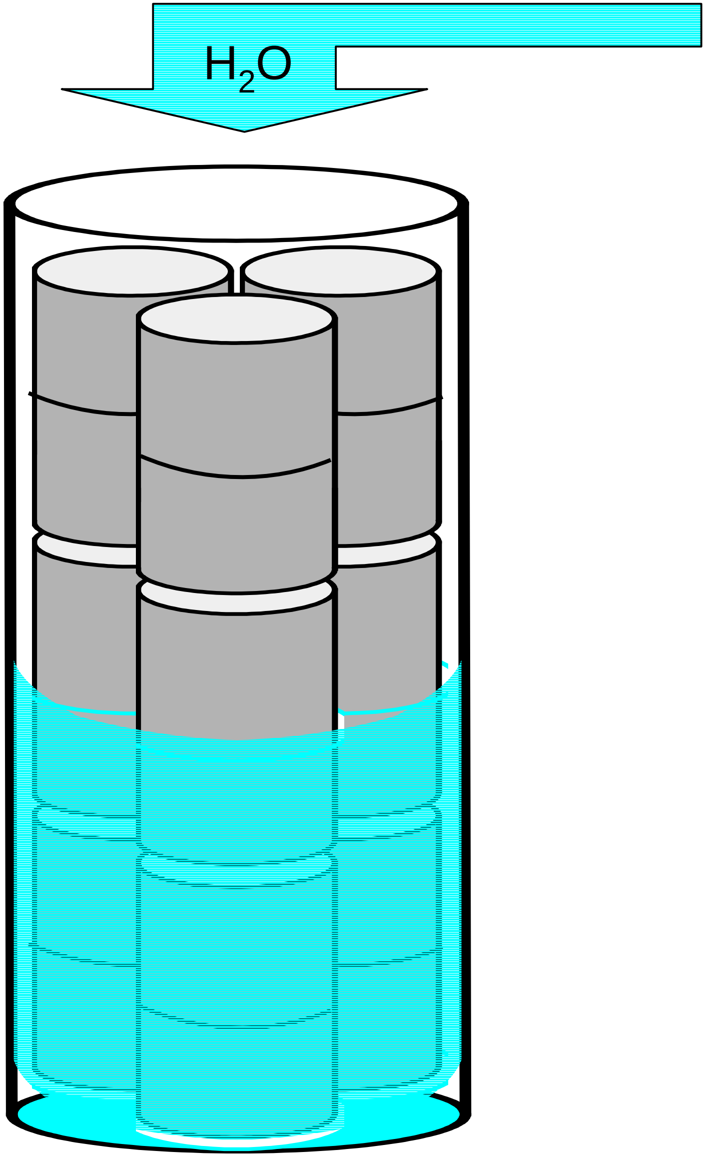
Wet supercritical CO_2 experimental set up



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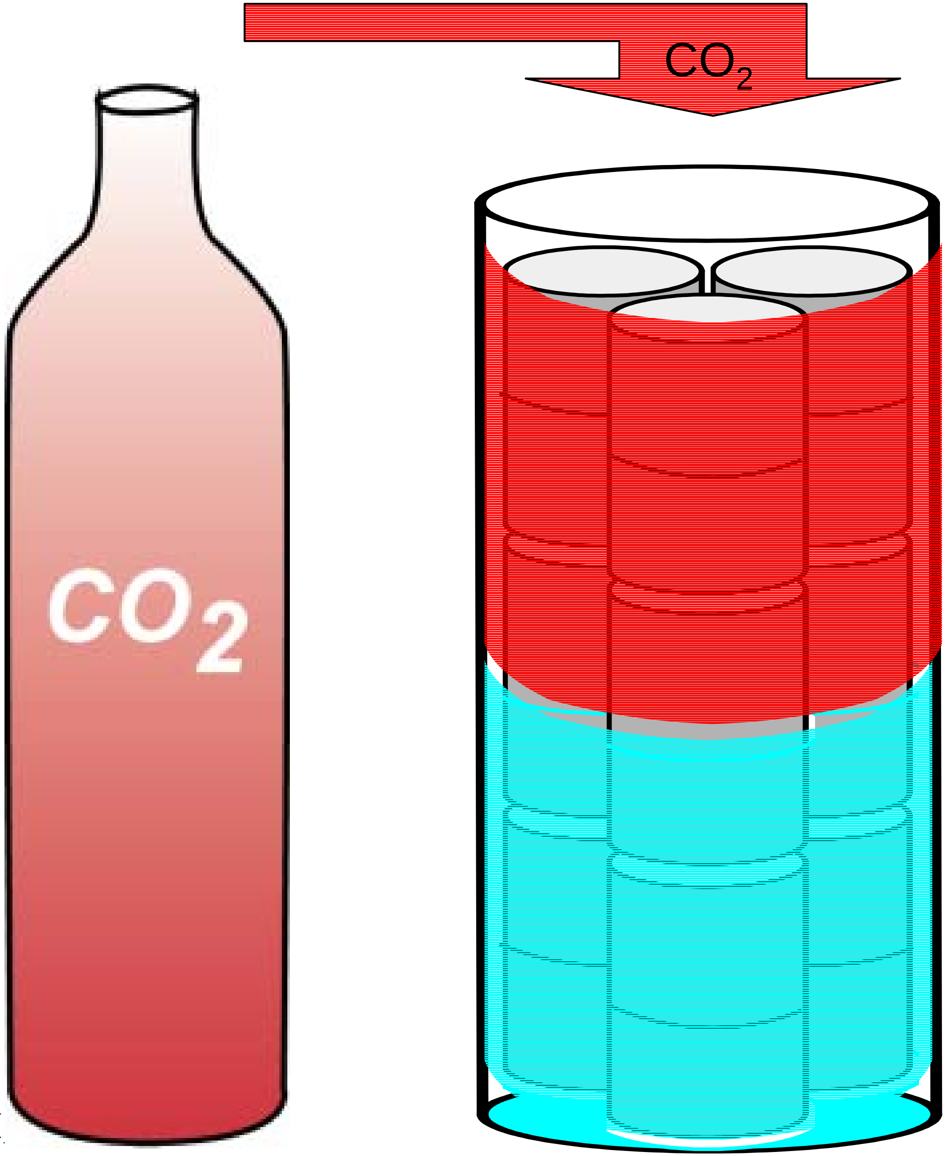
Wet supercritical CO_2 experimental set up



Supercritical CO_2 phase saturated with water

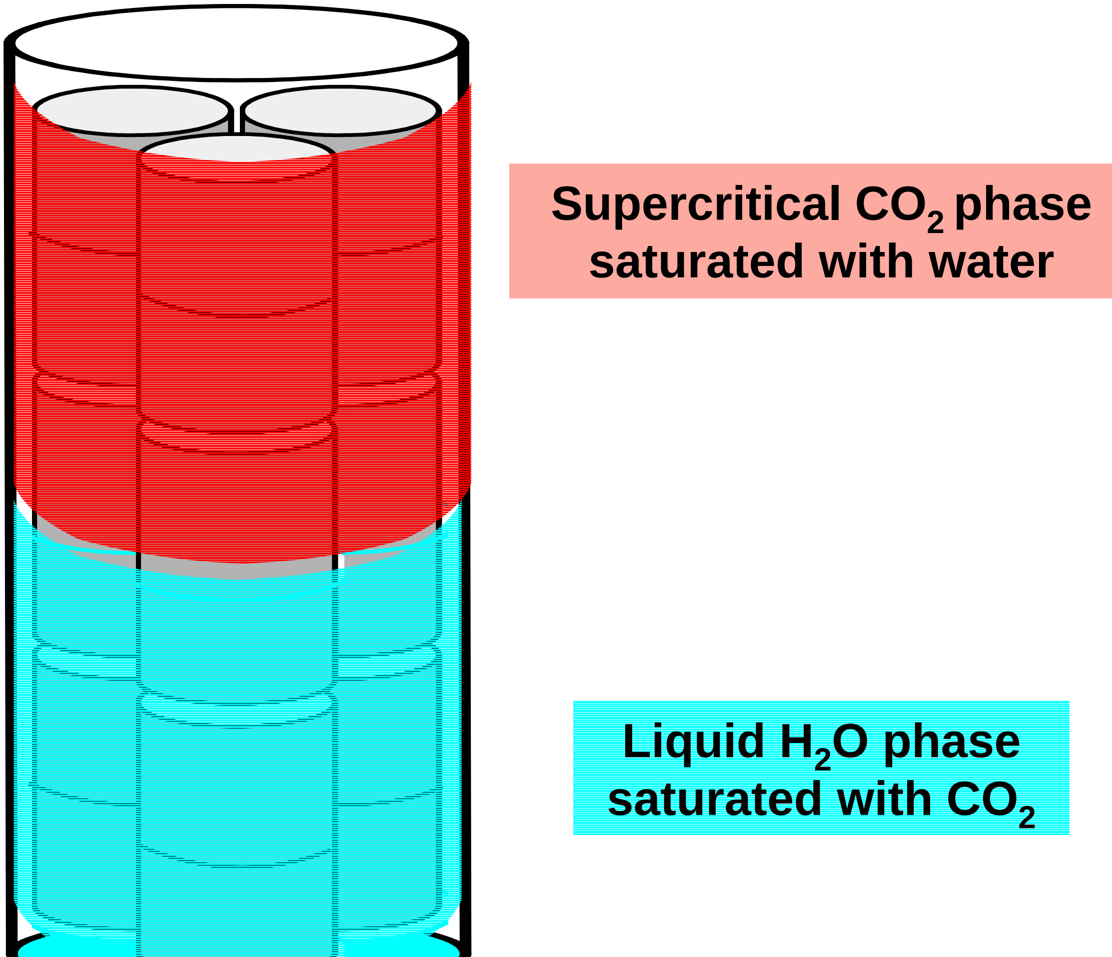
Liquid H_2O phase saturated with CO_2

Wet supercritical CO_2 experimental set up

TEST STOP (depressurization of vessel) then **MEASUREMENTS**

- 1. pH of fluid in vessel
- 2. Collection of samples and characterization (weight, dimensions, pH in initial fluid)
- 3. Sample in middle position (CO_2/H_2O boundary) for chemical analyses :

Scanning Electron Microscopy (SEM)



Note:
Other samples for :
- Mechanic resistance tests
- Mercury porosimetry
- Whole sample chemistry

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Wet supercritical CO_2 experimental set up

Experimental design, titanium made vessel, (opened, at left) disposition of several material cores crowns in the vessel, vessel closed in its running configuration (right)

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Measurements required to identify and quantify the carbonatation process

- Chemical and mineral matrix composition before and after CO_2 attack by:
  - Weight variation measurement
  - Thickness measurement of the alteration front
  - XRD analysis
  - SEM-EDS analysis

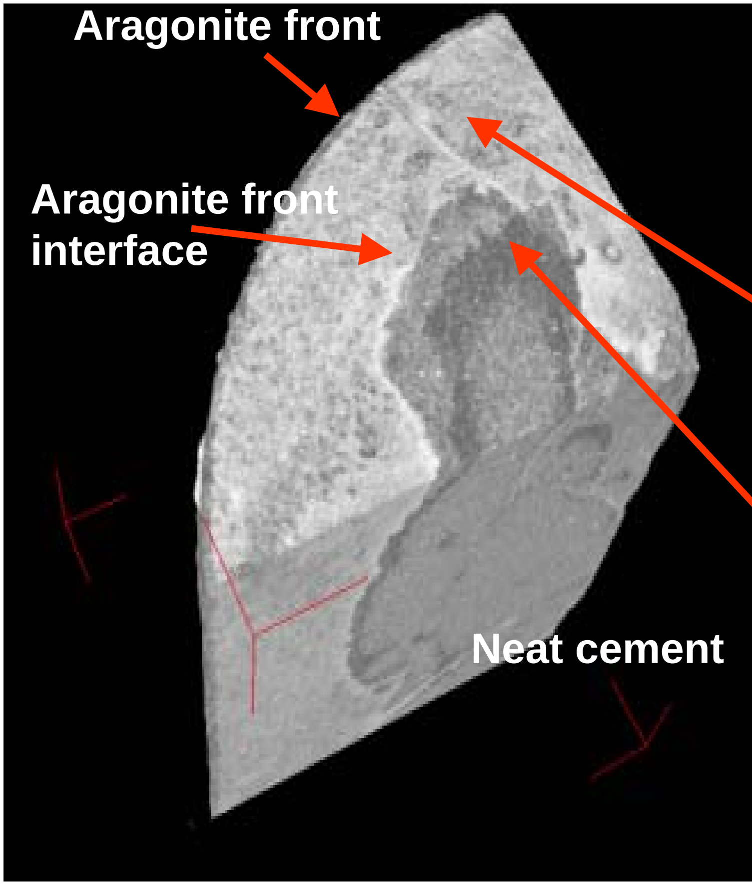
- Characterisation and visualization of matrix porosity and/or "permeability" by:
  - BSE imaging
  - Variation of water loss % versus square root of time measurement
  - Laboratory visualization of Cement-CO_2 Interaction

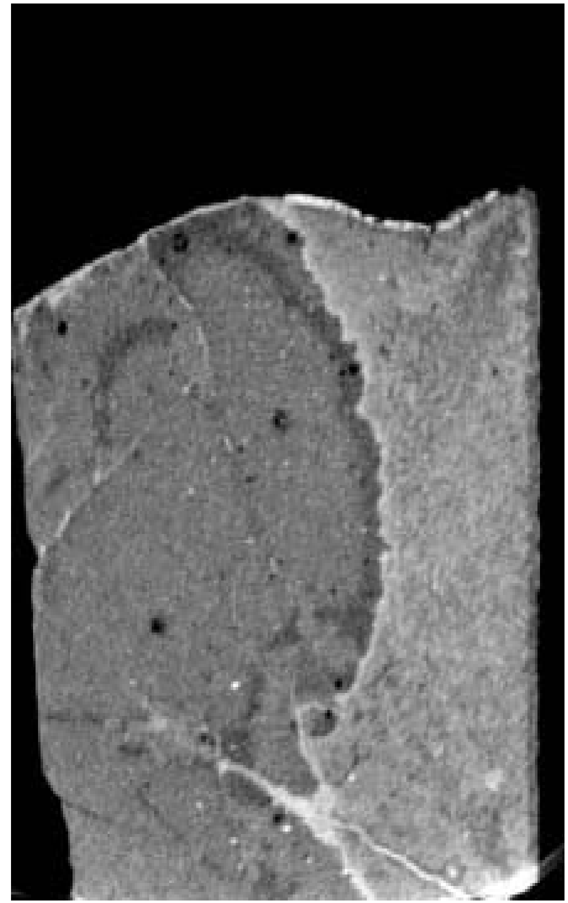
- Fluid analysis by:
  - pH variation measurement
  - Water production measurement

XR microtomography visualization with Virtual Reality software to evaluate well cement samples after CO_2 attack

view of CT scanned sample.
Voxel size/Resolution: ~ 19 μm

XZ slice





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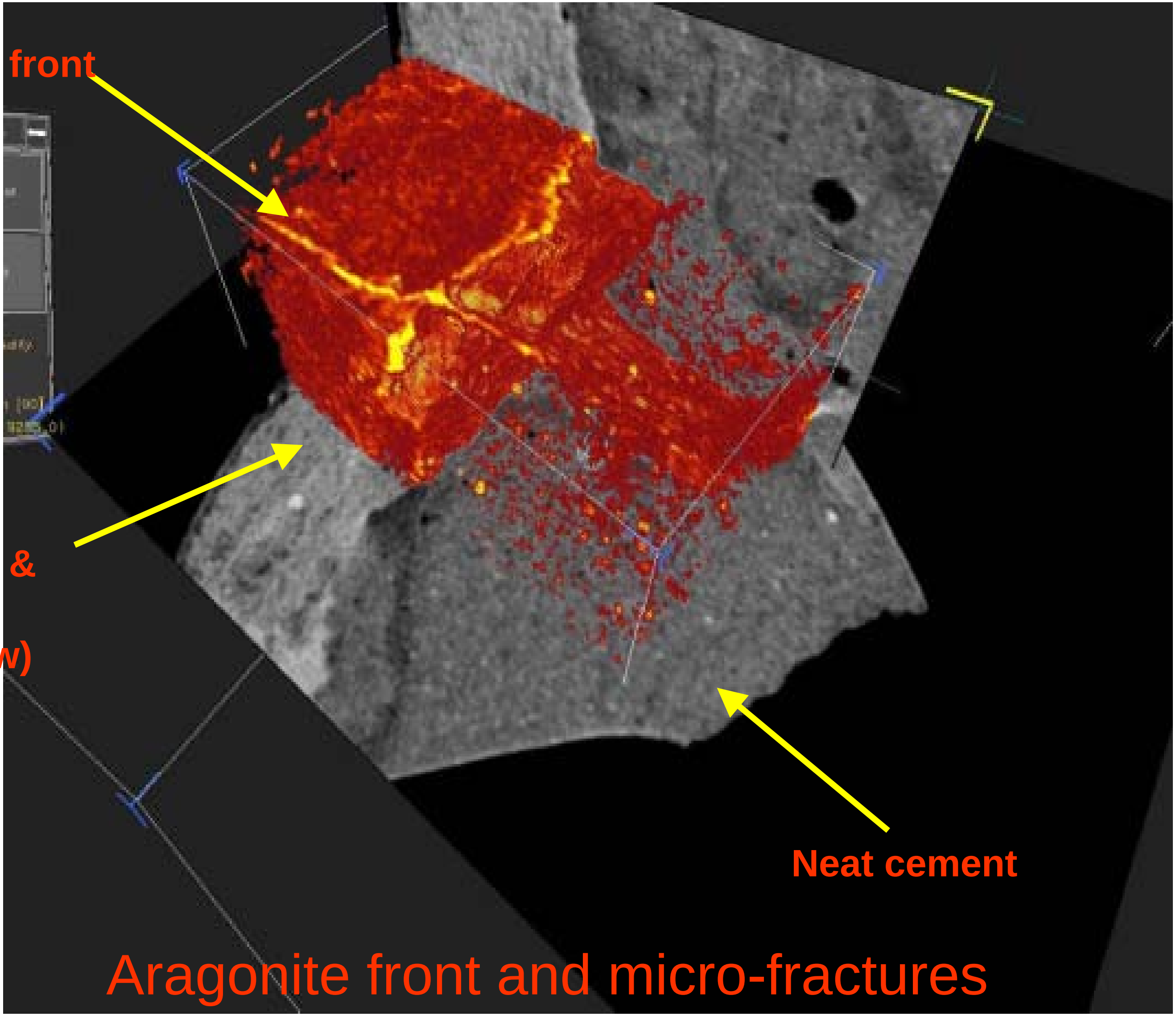
VR images – CO_2 attacked sample



Comparison of alteration in different cores of *Neat Portland*
90deg.C – 280 bars after 3 weeks

Core dimensions :

50 mm x 25 mm

Thickness of alteration ~ 6 mm

Core dimensions :

50 mm x 13 mm

Thickness of alteration ~ 6 mm

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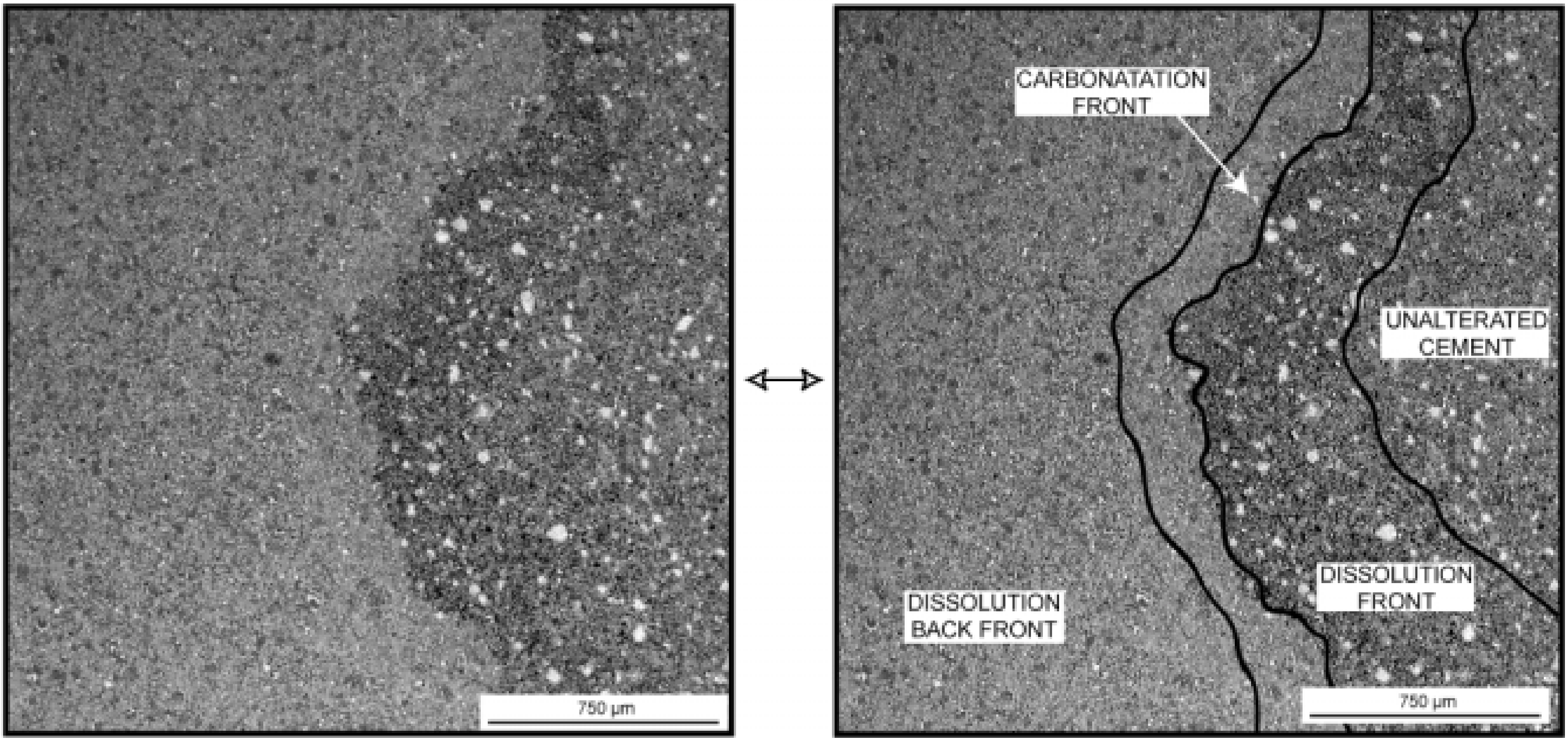
Carbonatation/Dissolution Process with Portland cement– 90deg.C-280 bars – 44 hours

N-280-44



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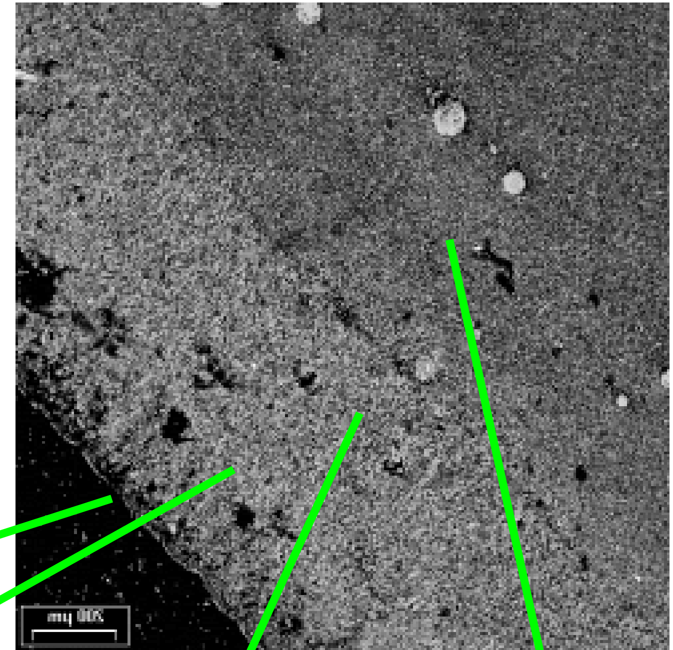
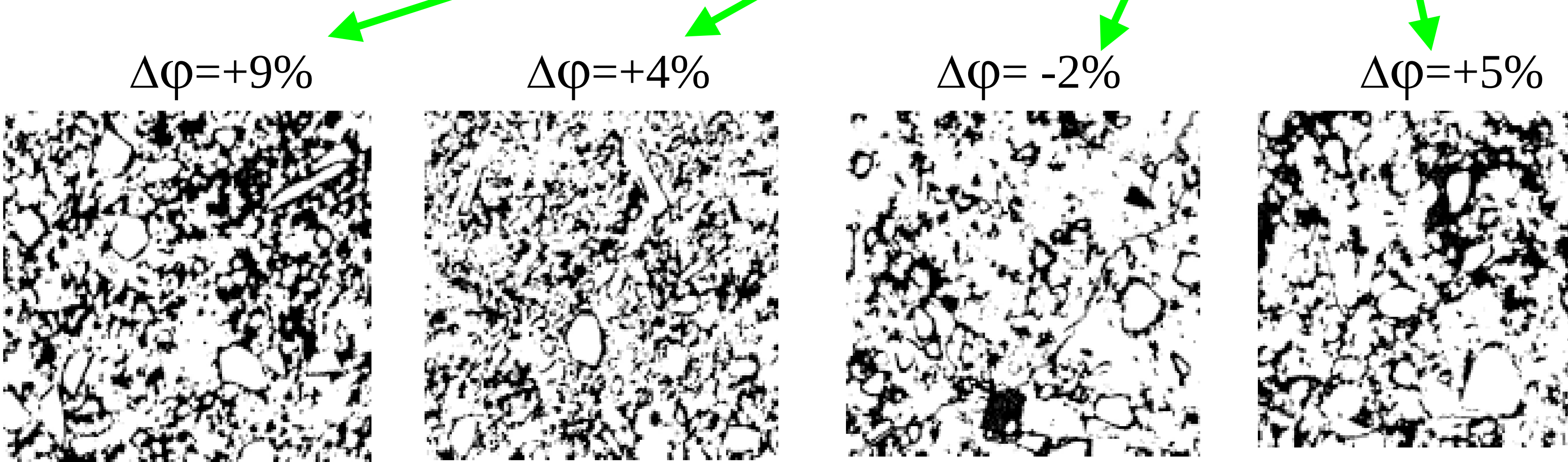
Porosity by SEM/BSE image analysis

Estimate of porosity variations for microcement

→ Using SEM/BSE imaging of the alteration rim.



Porosity (in black) measurements using BSE image analysis (70 x70 µm images)



What happens with Neat cement?

Cracks in wet CO_2 supercritical environment

strong alteration rims

strong carbonatation in the external fluid mainly located at the fluids interface (Aragonite)

After one month at 90deg.C-280 bars under wet CO_2 supercritical environment

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Alternative Material Testing

Matrix without cement:

, KH_2PO_4, Fly ash type C, Fly ash type F, Water, Boric acid

After one month at 90deg.C-280 bars under wet CO_2 supercritical environment

- Potassium phosphate reacts as an amorphous magnesium phosphate front called newberryite (MgHP04 33H2O)
- Altered slag particles are first plugged by newberryite to form a front
- This new phosphate is secondly altered to form the bobierite Mg3(PO4)2 8H2O in the backfront which is dissolved in the solution (precipitation)
- Dissolution in the core centre to

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Test of a Proprietary Cement Solution

After one month at 90 deg.C-280 bars under wet CO2 supercritical environment

good integrity, good mechanical properties
thin carbonatation rim (0.2mm)

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On-Going Work

- Testing of a number of commercial cement systems at 2-days, 1-3 weeks, 1-2-6 months
- Development and validation of an accelerated ageing test that would decrease long-term testing by a factor of 100
- Modelling of carbonatation process in cements

Conclusions

- Carbonatation of Portland cement in supercritical wet CO_2 is a very effective process (about 0.2 mm/day for a neat cement)

- Carbonatation is comparable to a metasomatic process with local equilibrium progressing from the external side associated to local and transitory decrease of the porosity

    - Portlandite and CSH are progressively consumed to produce carbonates (aragonite and calcite) + silica and water

    - At the rear of the carbonatation front, the neoformed carbonate and silica are dissolved increasing the porosity and resulting to a strong degradation of the cement.

- Need for the industry to agree on the specifications of a standard testing equipment

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Models for Estimation of Large-scale Leakage along Multiple Wells

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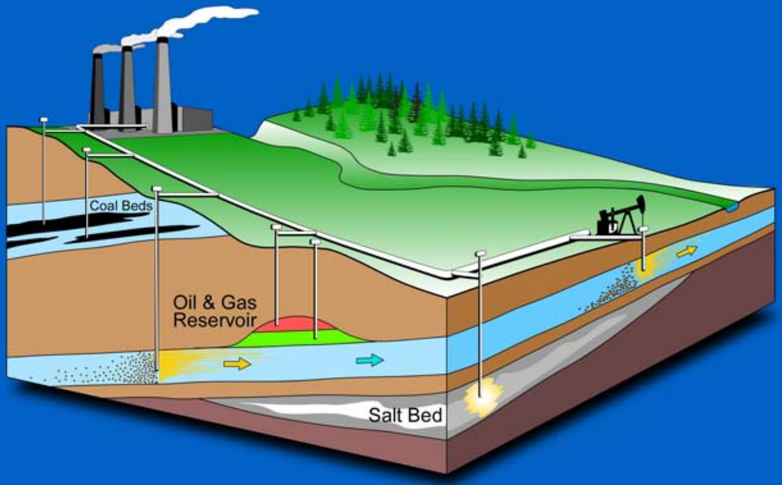
Princeton University

EUB

UNIVERSITAS BERGENSIS

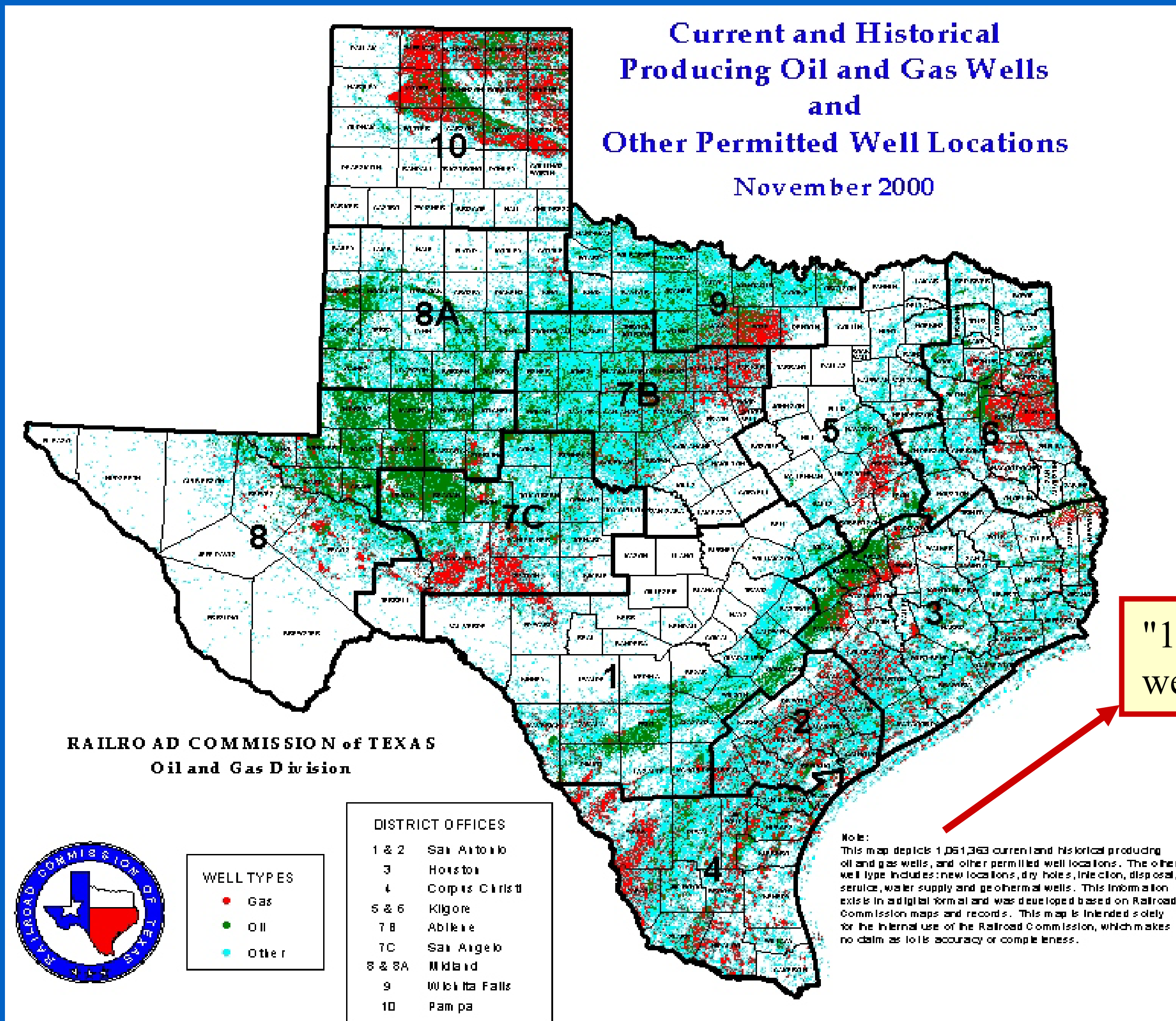
Outline

- **Analysis of Existing Wells: Alberta Basin**
- **New Computational Tools for Leakage Simulation**
  - Analytical Solutions for Injection and Leakage
  - Numerical Upscaling for Grid Blocks with Leaky Wells
- **Semi-Analytical Solutions**
  - Injection dynamics
  - One leaky well
  - Multiple leaky wells
  - Multiple layers



- **Current Field Applications**

Mature Sedimentary Basins: Example

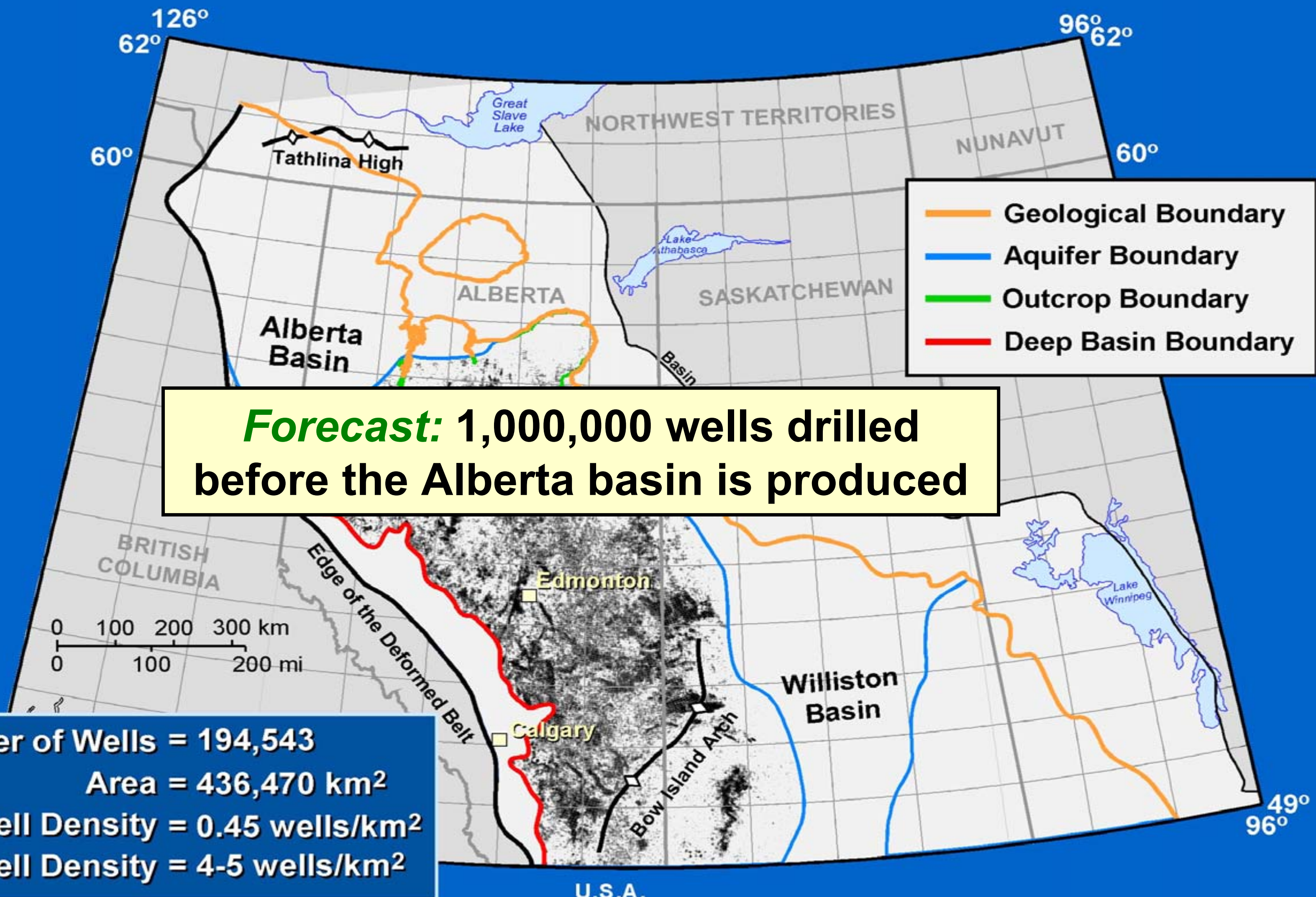


"1,061,363 … permitted well locations …"

Mature Sedimentary Basins: Example

Viking Formation: **195,000 Wells**

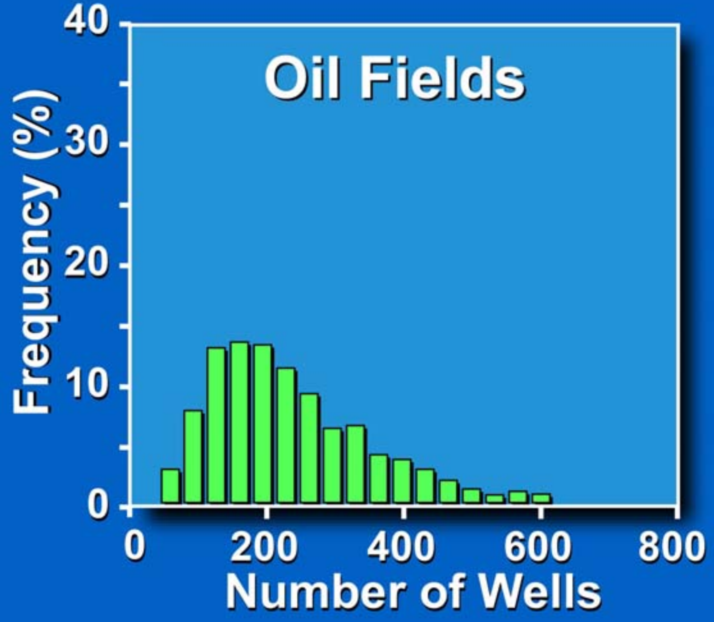
Alberta Basin: **350,000 Wells**

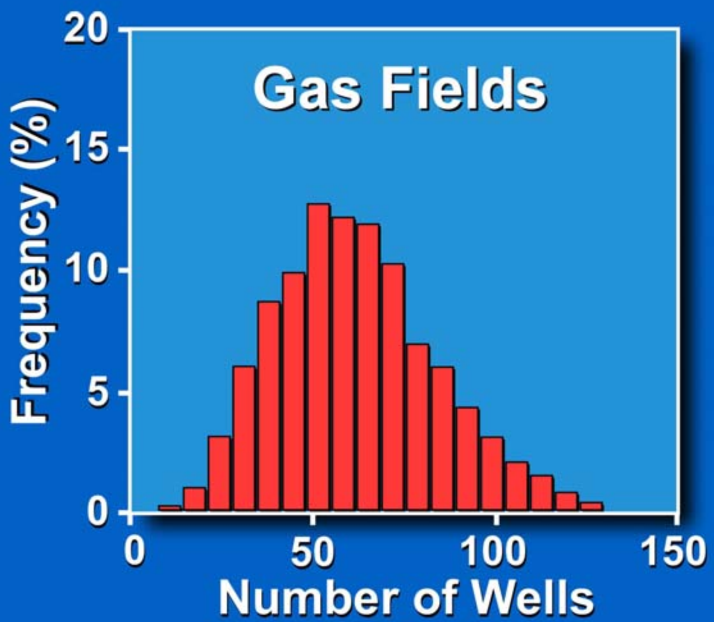


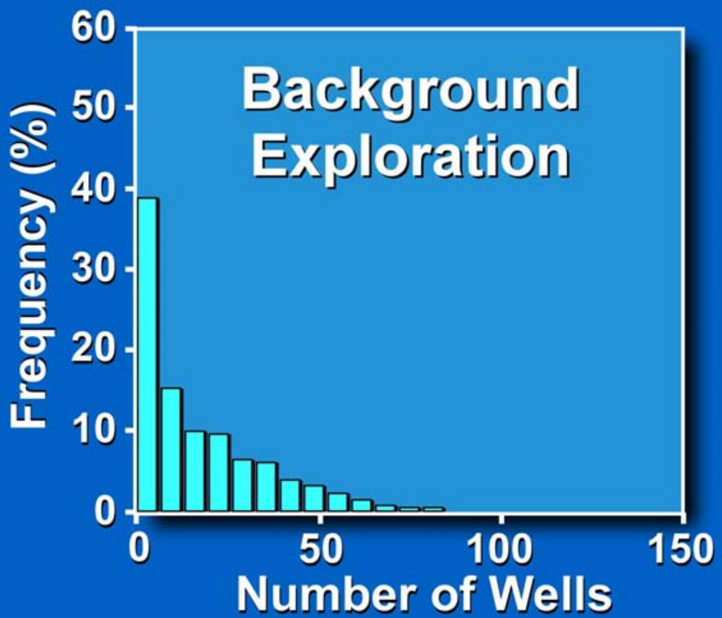
Forecast: **1,000,000 wells drilled before the Alberta basin is produced**

Number of Wells = 194,543
Area = 436,470 km²
Avg. Well Density = 0.45 wells/km²
Max. Well Density = 4-5 wells/km²

Number of Wells within 5 km of an Injection Well in the Alberta Basin, Canada

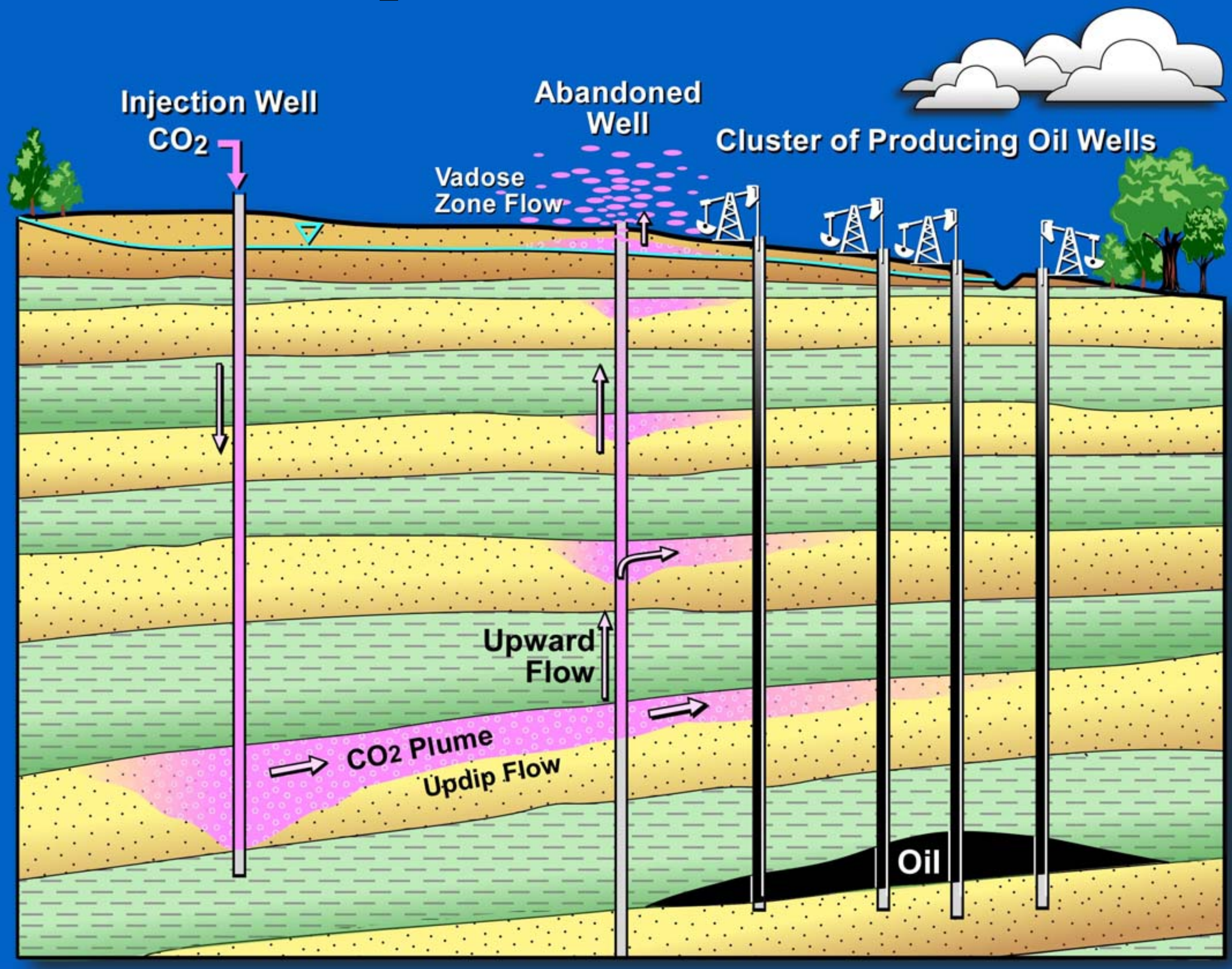




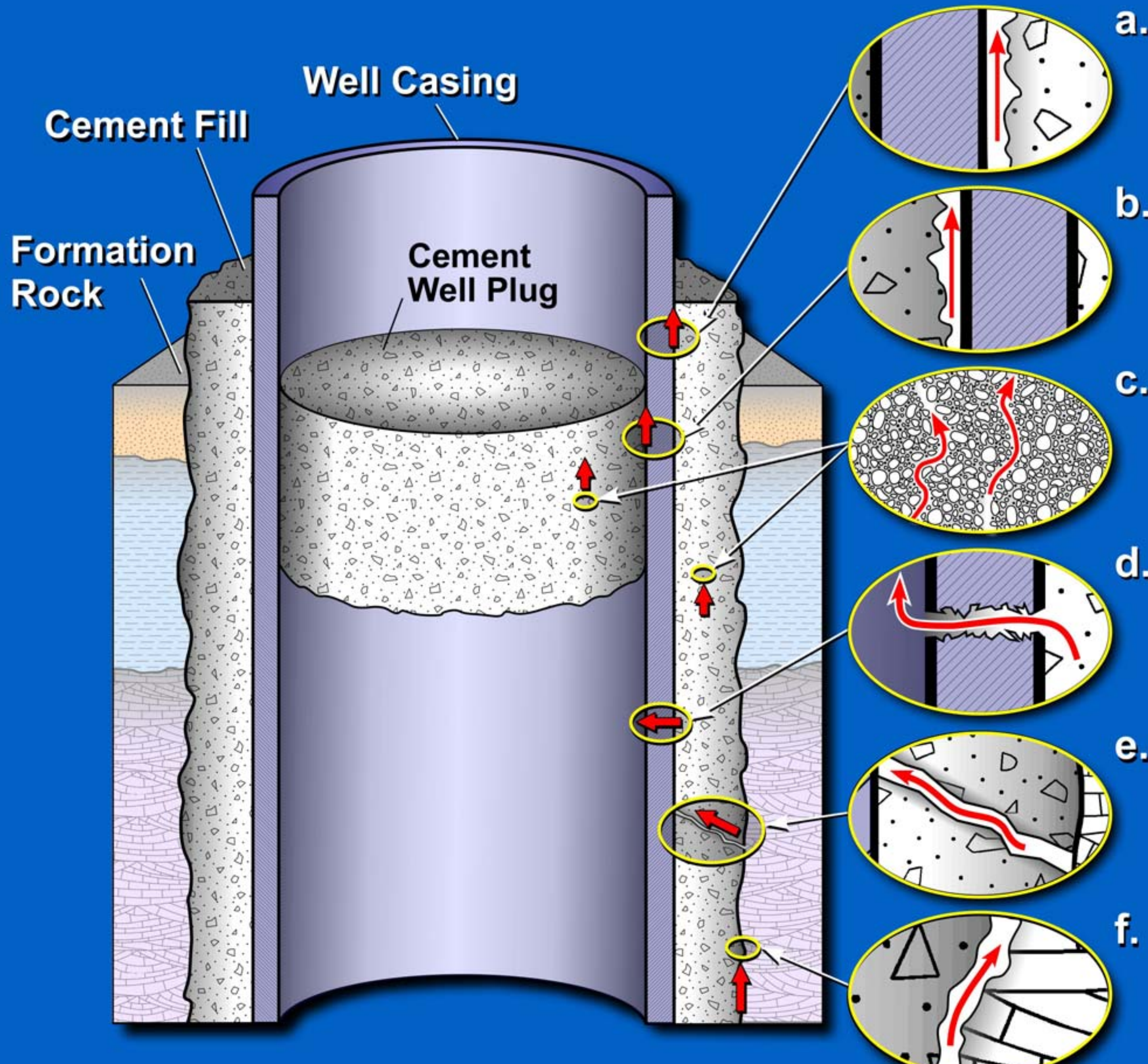


From: Gasda, S.E., S. Bachu, and M.A. Celia, *Environmental Geology*, 2004.

Potential CO_2 Migration and Leakage Paths



Potential Gas Migration Paths along a Well



Mathematical Models

- **Numerical Methods**

  - Solve multiphase flow equations (DynaFlow, Eclipse, TOUGH2, NUFT)

  - Allow for general geometries

  – Require fine grids around wells → potentially large computational requirement

  – Require function upscaling to use larger grid blocks (Gasda and Celia, 2005)

- **Analytical Solutions**

  - Require restrictive assumptions

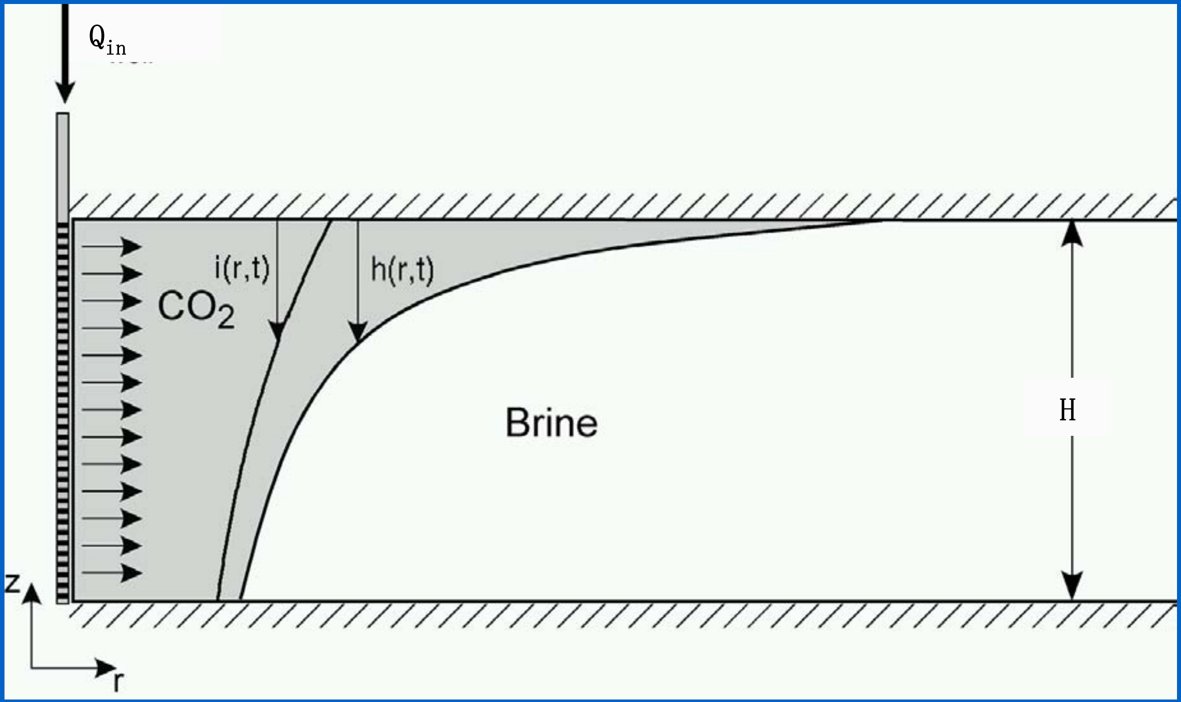
  - Are much easier to compute

  - New solutions allow for practical analysis of leakage risk

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)**

General Similarity Solution (1)



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

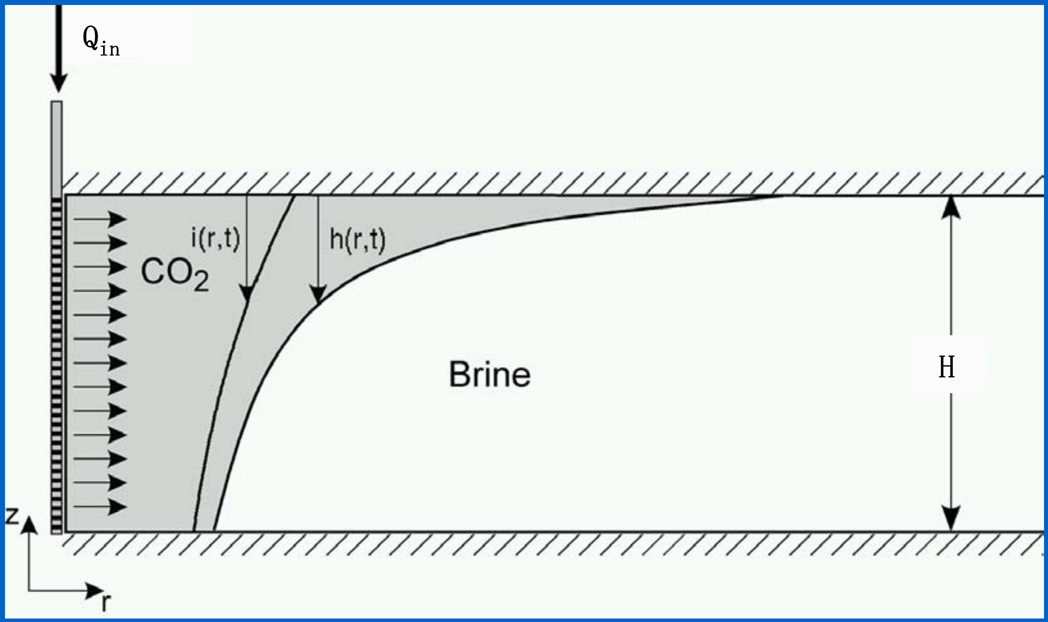
$$-2\pi r\varphi\frac{\partial(h-i)}{\partial t}=\frac{1}{1-S_{res}}\frac{\partial Q_{cw}}{\partial r}+\frac{1-\gamma_2}{1-S_{res}}\frac{\partial Q_c}{\partial r}+\frac{1-\gamma_1}{1-S_{res}}\frac{\partial Q_w}{\partial r}$$

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

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

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

General Similarity Solution (2)



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

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

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

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

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

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

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

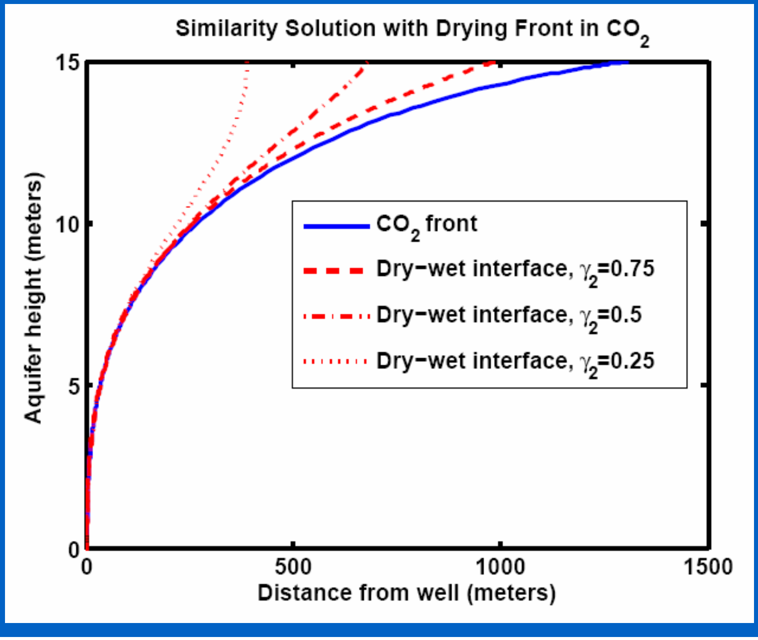
$$-\frac{di'}{d\chi} = \frac{4\gamma_2\Gamma\lambda_1}{\chi}\frac{d}{d\chi}\left(i'\chi\frac{d}{d\chi}(p' + h' + \vartheta i')\right)$$

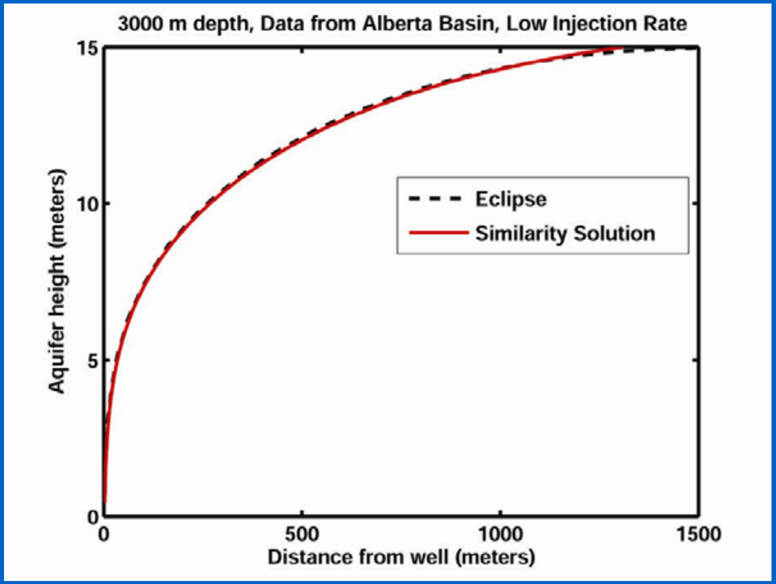
$$-\frac{d}{d\chi}(h' - i') = \frac{4\Gamma\lambda_2}{\chi}\frac{d}{d\chi}\left((h' - i')\chi\frac{d}{d\chi}(p' + h')\right) + \frac{4(1 - \gamma_2)\Gamma\lambda_1}{\chi}\frac{d}{d\chi}\left(i'\chi\frac{d}{d\chi}(p' + h' + \vartheta i')\right) + \frac{4\Gamma(1 - \gamma_1)}{\chi}\frac{d}{d\chi}\left((1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

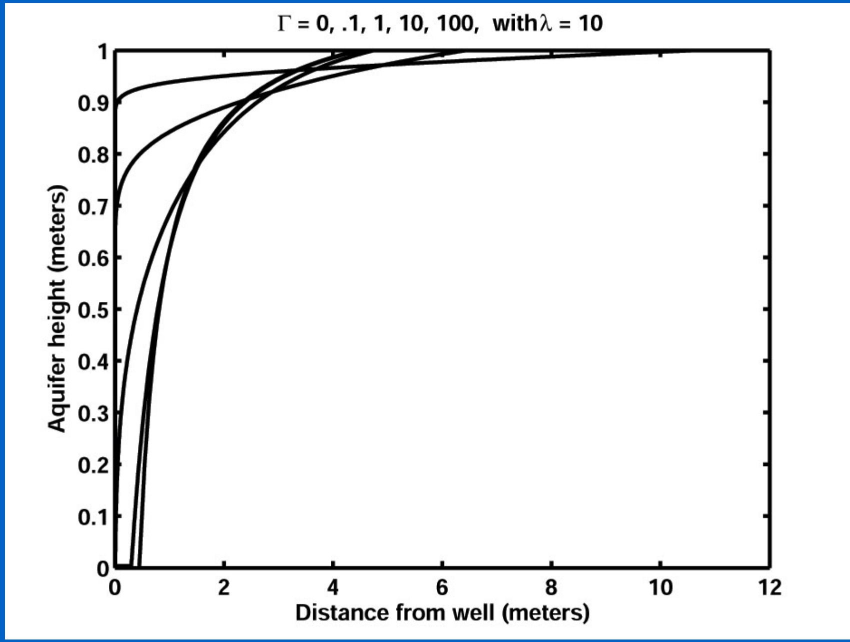
$$\chi \equiv r^2 / \tau$$

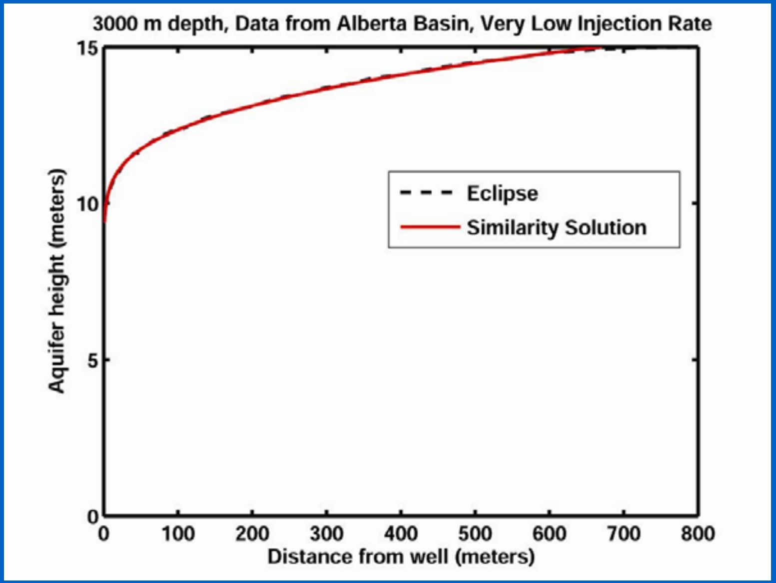
From: Nordbotten and Celia, *JFM*, (under review) 2005.

Similarity Solutions









Threshold for Viscous Domination

Density appears in the dimensionless parameter:

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

When $\Gamma < 0.5$, density effects can be neglected.

Resulting Solutions

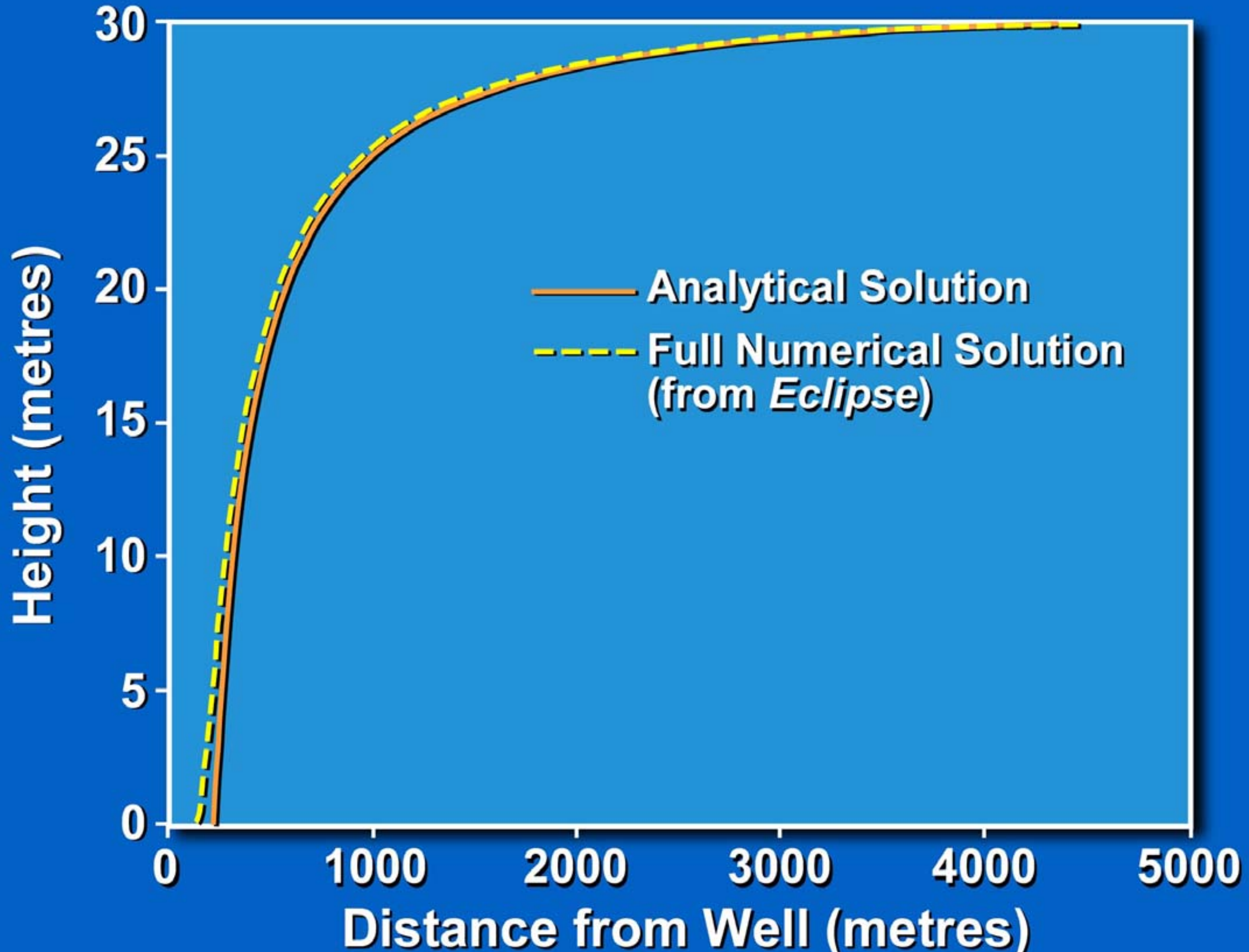
For viscosity dominated injections, the plume shape is given by:

$$\frac{h(r,t)}{H} = \frac{1}{\lambda_c - \lambda_w}\left[\sqrt{\frac{\lambda_c \lambda_w Q_{in} t}{\varphi \pi H r^2}} - \lambda_w\right]$$

From: Nordbotten, Celia, Bachu, *TiPM*, 2005.

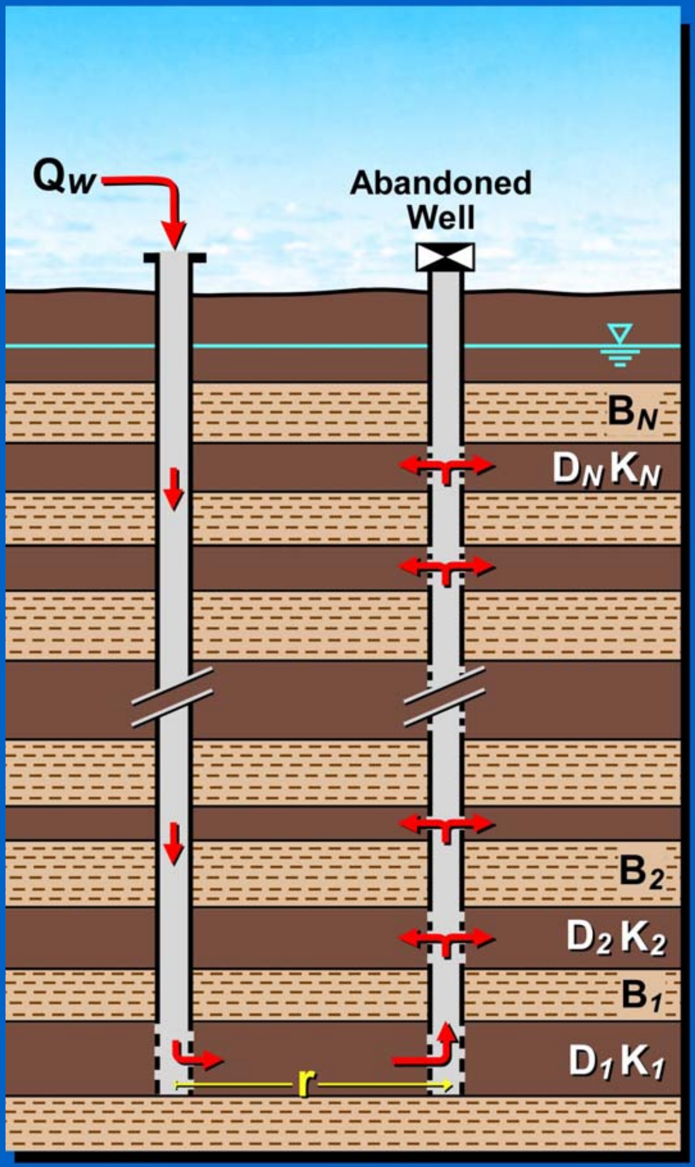
Simplified Analytical Solution: Two-Phase Flow

Analytical solution (sharp interface) versus effective saturation from *Eclipse*



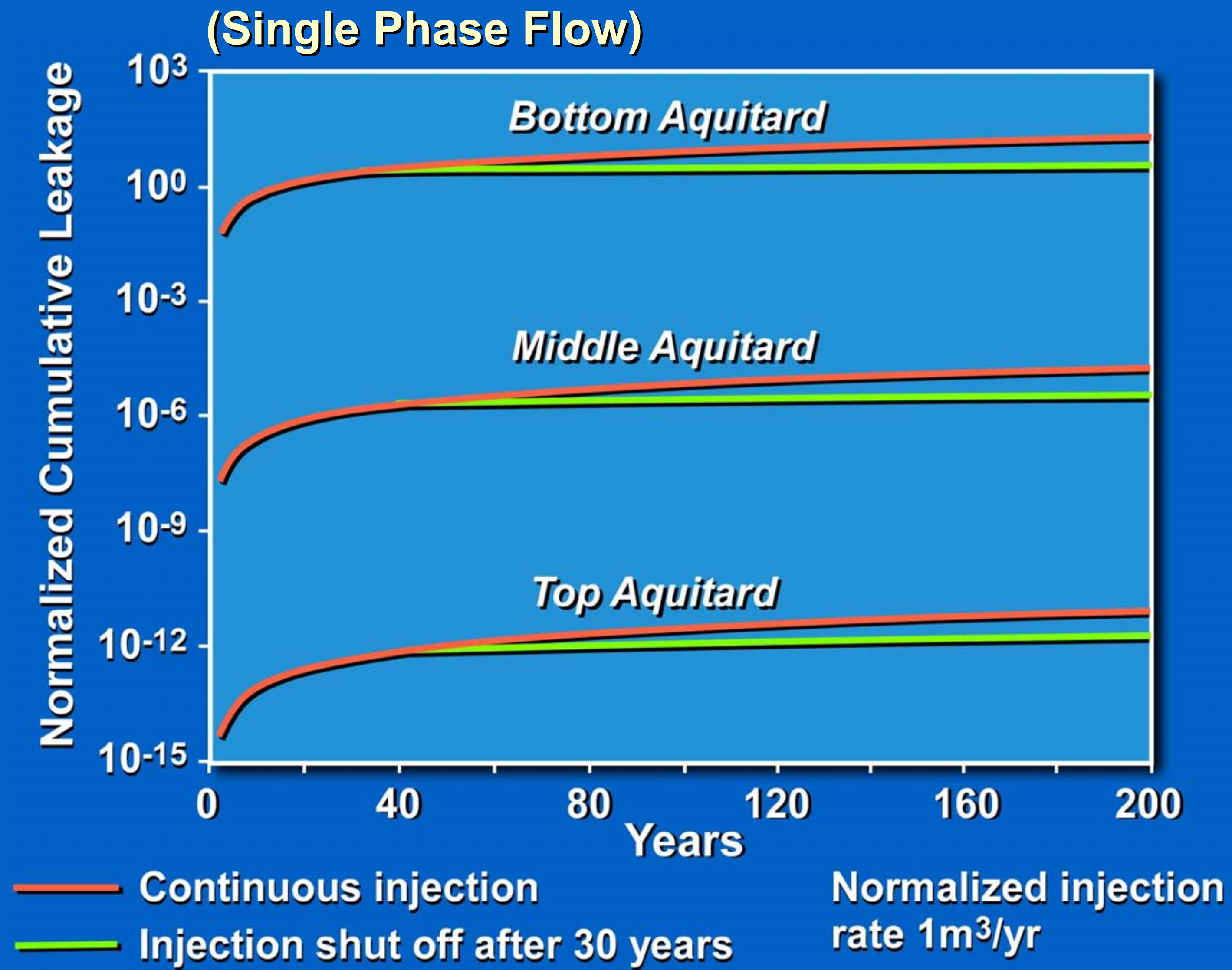
From: Nordbotten, Celia, Bachu, *TiPM*, 2005; Bachu, Nordbotten, Celia, *GHGT-7*, 2004.

Solutions with Leakage

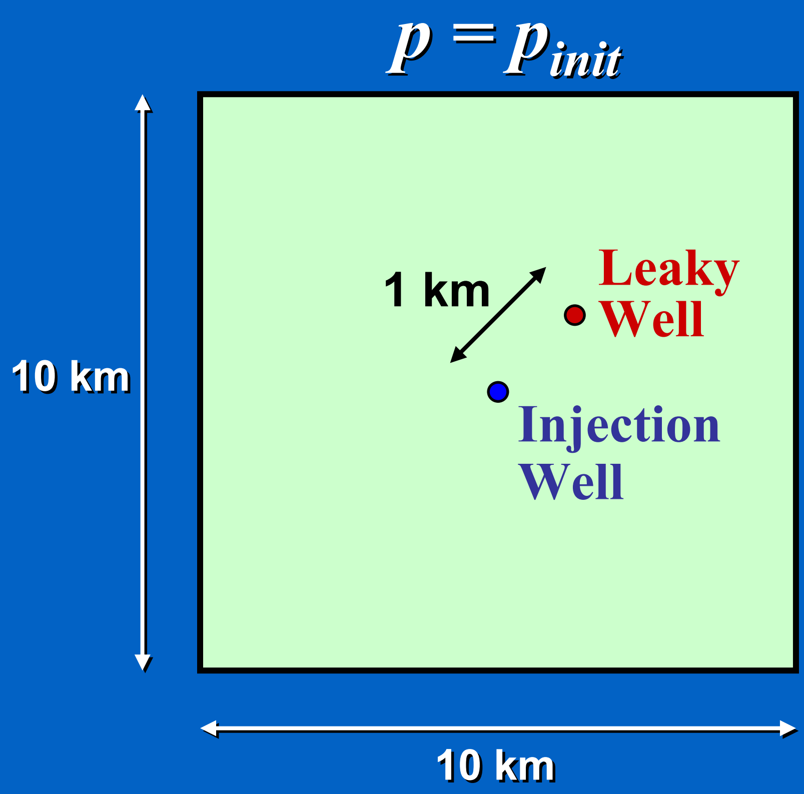


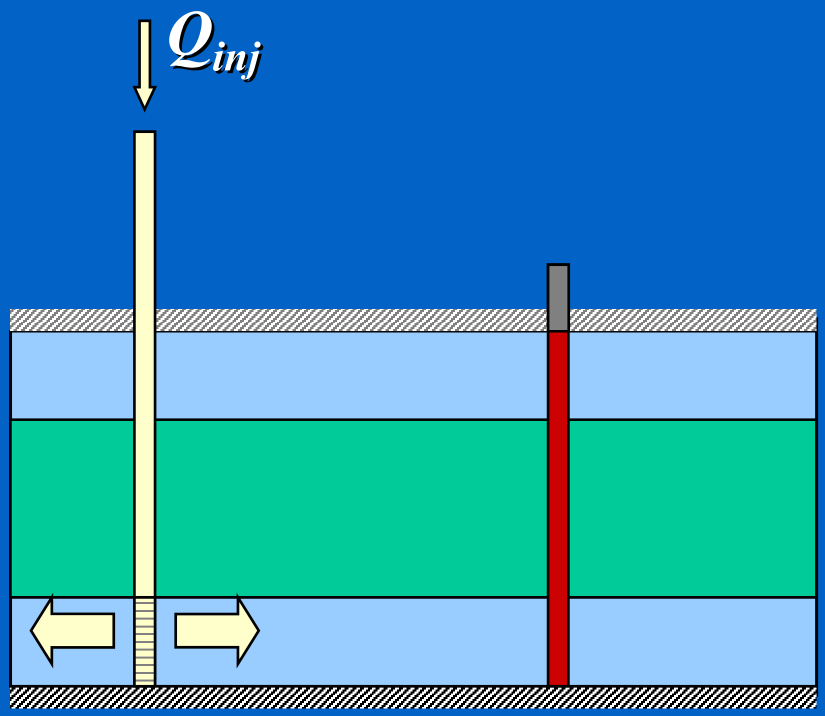
- Multiple aquifers/aquitards
- Multiple active and passive wells
- Single-phase Flow:
  - Leakage can be evaluated directly for any time
- Multi-phase Flow:
  - Time-stepping is required!

New Analytical Solution: Applications

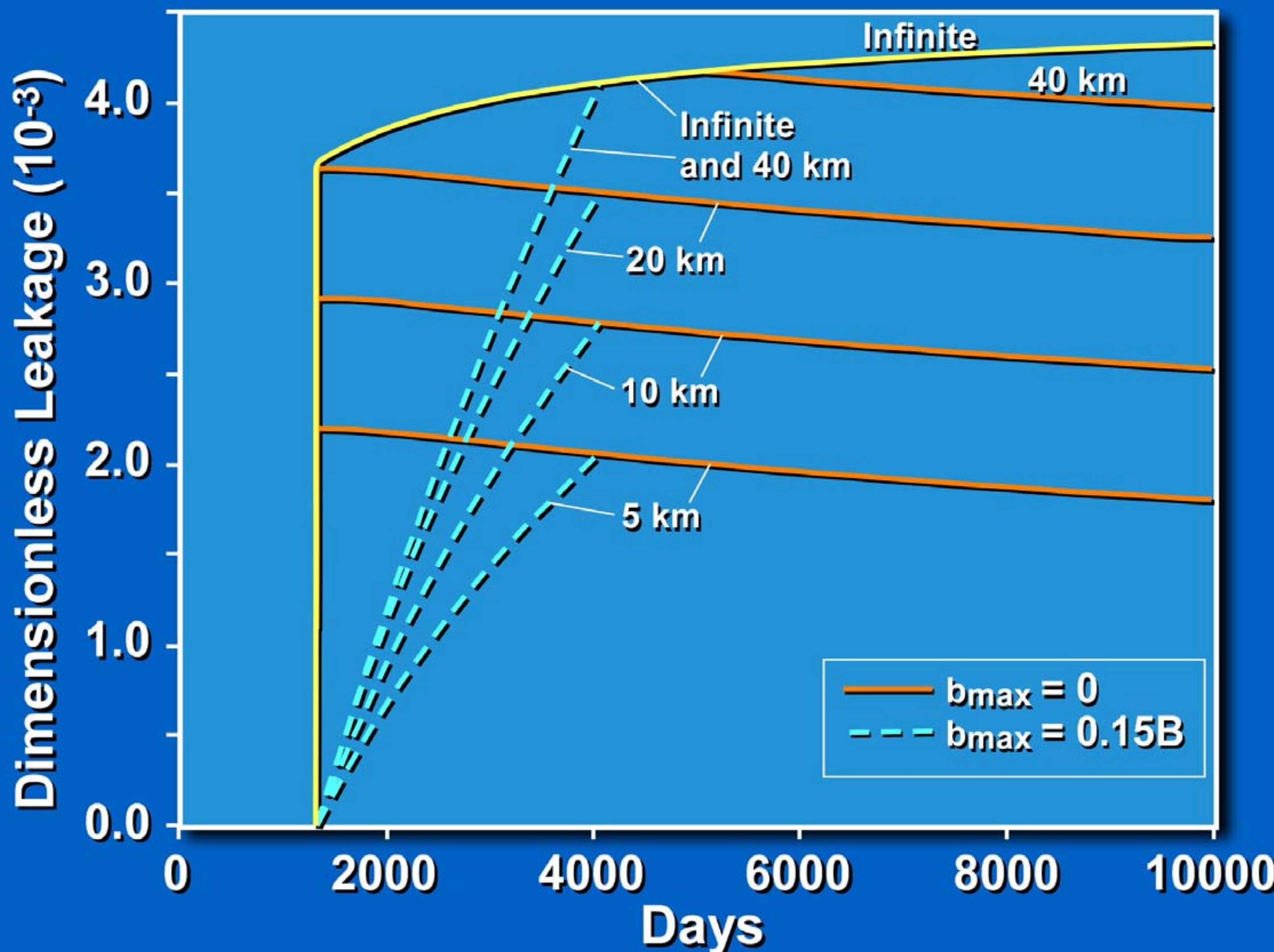


Leakage of CO_2: Single Well Test Problem



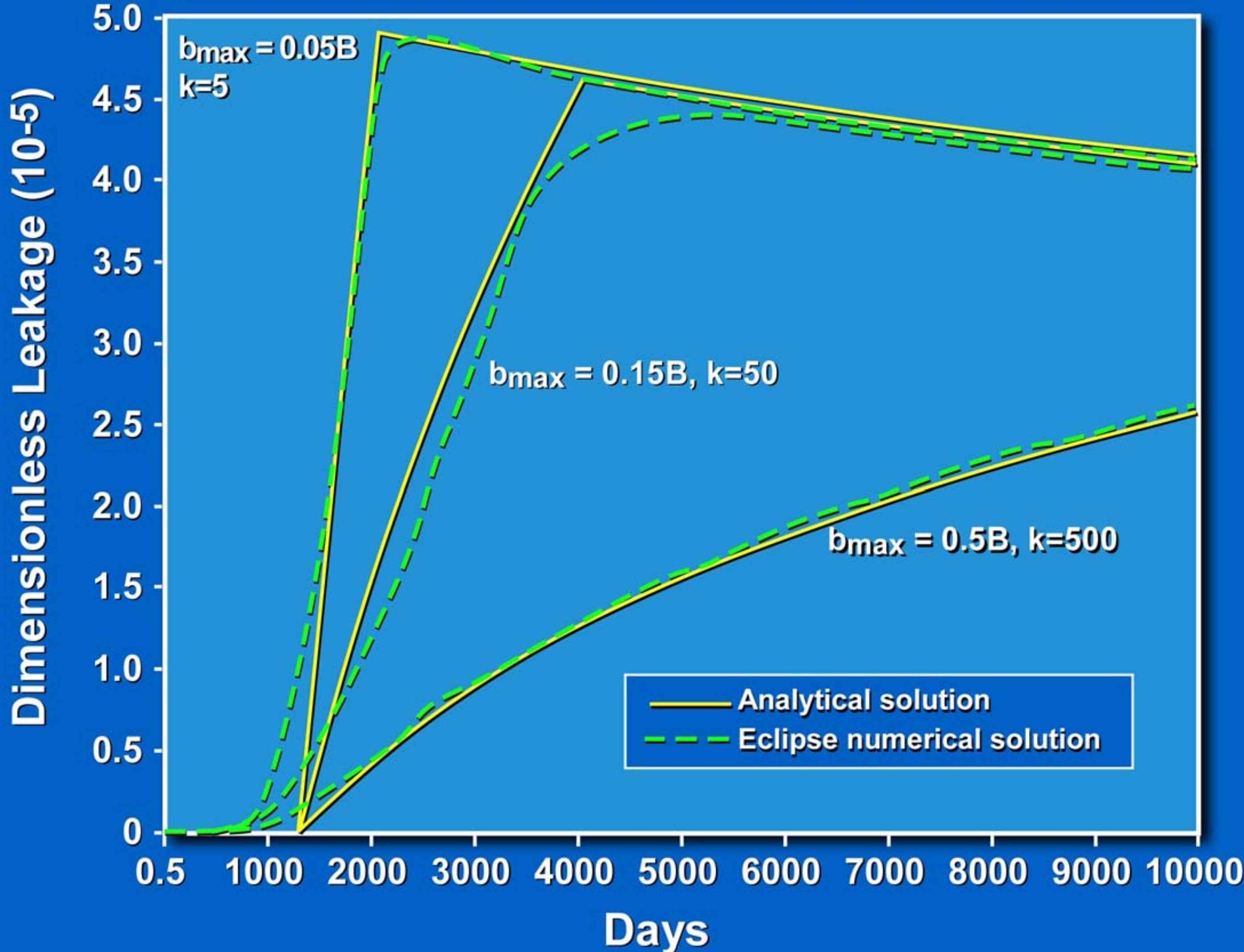


CO_2 Leakage: Analytical Solutions



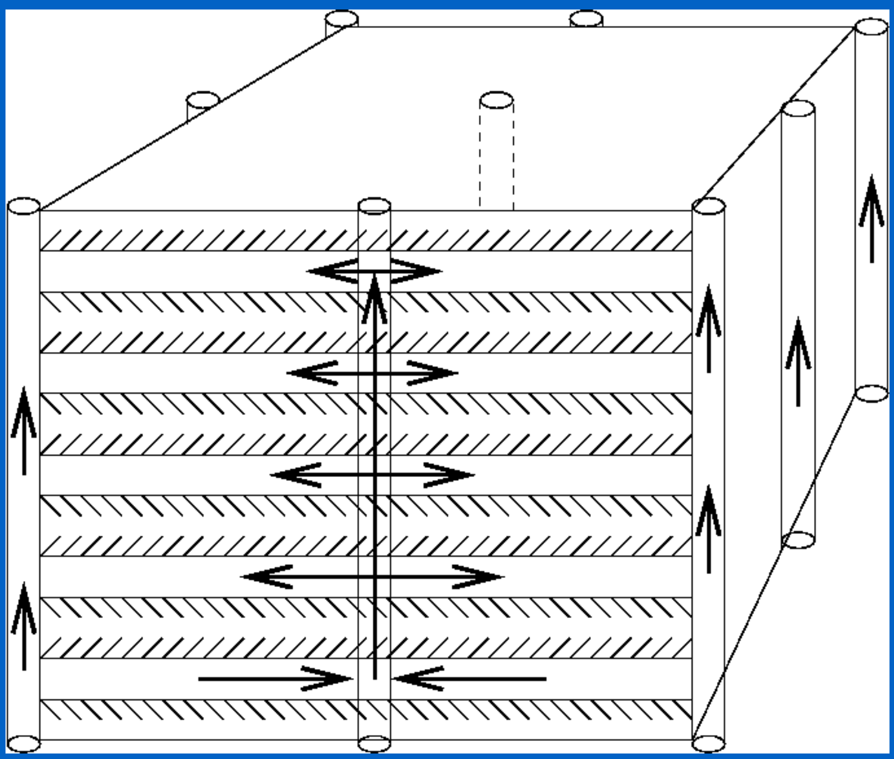
From: Nordbotten, Celia, Bachu, *ES&T*, 2005.

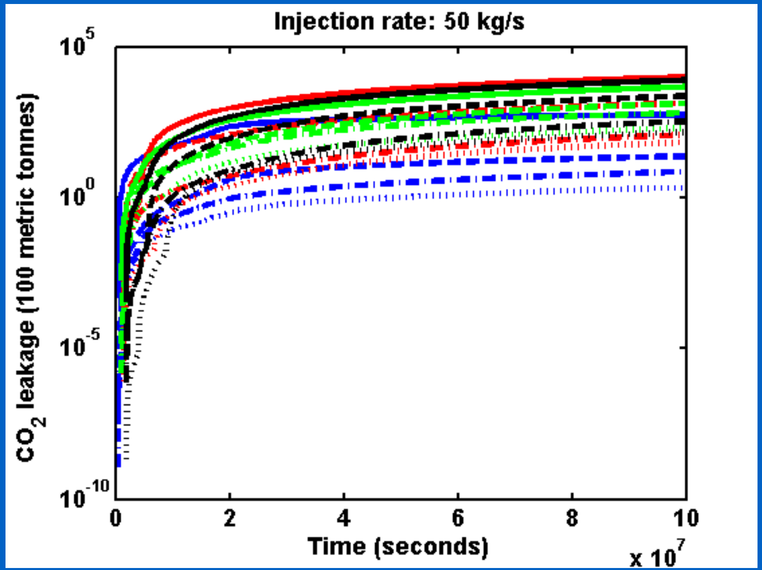
CO_2 Leakage: Analytical vs. Numerical

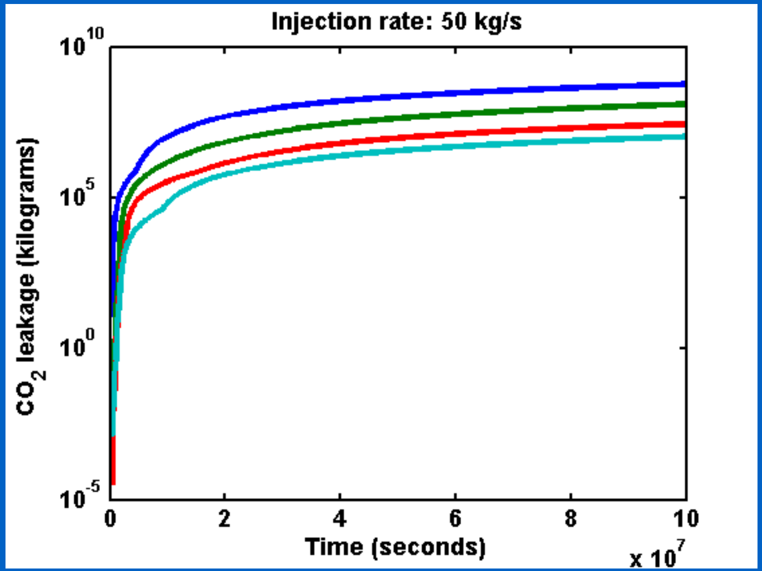


From: Celia, Bachu, Nordbotten, *GHGT-7*, 2004; Nordbotten, Celia, Bachu, *ES&T*, 2005.

Extention to Multiple Wells and Multiple Layers







Comments: Model Inputs

- Physical Parameters
  - Formation parameters (permeabilities, porosities , layer thicknesses, residual saturations, phase partitioning)
  - Leaky-well parameters (permeabilities, porosities, vertical variability, degradation dynamics)
- Variability and Uncertainty
  - We have no quantitative information on leaky-well parameters → Investigate different probability distributions for k_{well}.
  - We have much better information on formation parameters → much less uncertainty
  - Analytical models allow for layer-by-layer heterogeneity, but only very simplified local heterogeneity within layers

Comments: Model Outputs

- Leakage Rates as a Function of:
  - Spatial density of leaky wells
  - Probability distribution type (for k_{well})
  - Probability distribution parameters (for k_{well})
  - Formation parameters
  - Vertical location of leakage measurement
  - Vertical location of injection well
- "Critical Radius" for Leakage Measurements
- Definition and Measures of Risk
- Farther-field Brine Leakage Estimates

References (Well Leakage)

Nordbotten, J.M. and M.A. Celia, "Similarity Solutions for Fluid Injection into Confined Aquifers", under review, *Journal of Fluid Mechanics*, 2005.

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Nordbotten, J., M.A. Celia, and S. Bachu, "Injection and Storage of CO2 in Deep Saline Aquifers: Analytical Solution for CO2 Plume Evolution during Injection", *Transport in Porous Media*, *58*(3), 339-360, 2005.

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Celia, M.A., S. Bachu, J.M. Nordbotten, S.E. Gasda, and H.K. Dahle, "Quantitative Estimation of CO2 Leakage from Geological Storage: Analytical Models, Numerical Models, and Data Needs, *Proc. GHGT-7 Meeting,* Vancouver, September 2004.

Bachu, S., J.M. Nordbotten, and M.A Celia, "Evaluation of the Spread of Acid Gas Plumes injected into Deep Saline Aquifers in Western Canada as an Analogue for CO2 Injection in Continental Sedimentary Basins", *Proc. GHGT-7 Meeting*, Vancouver, September 2004.

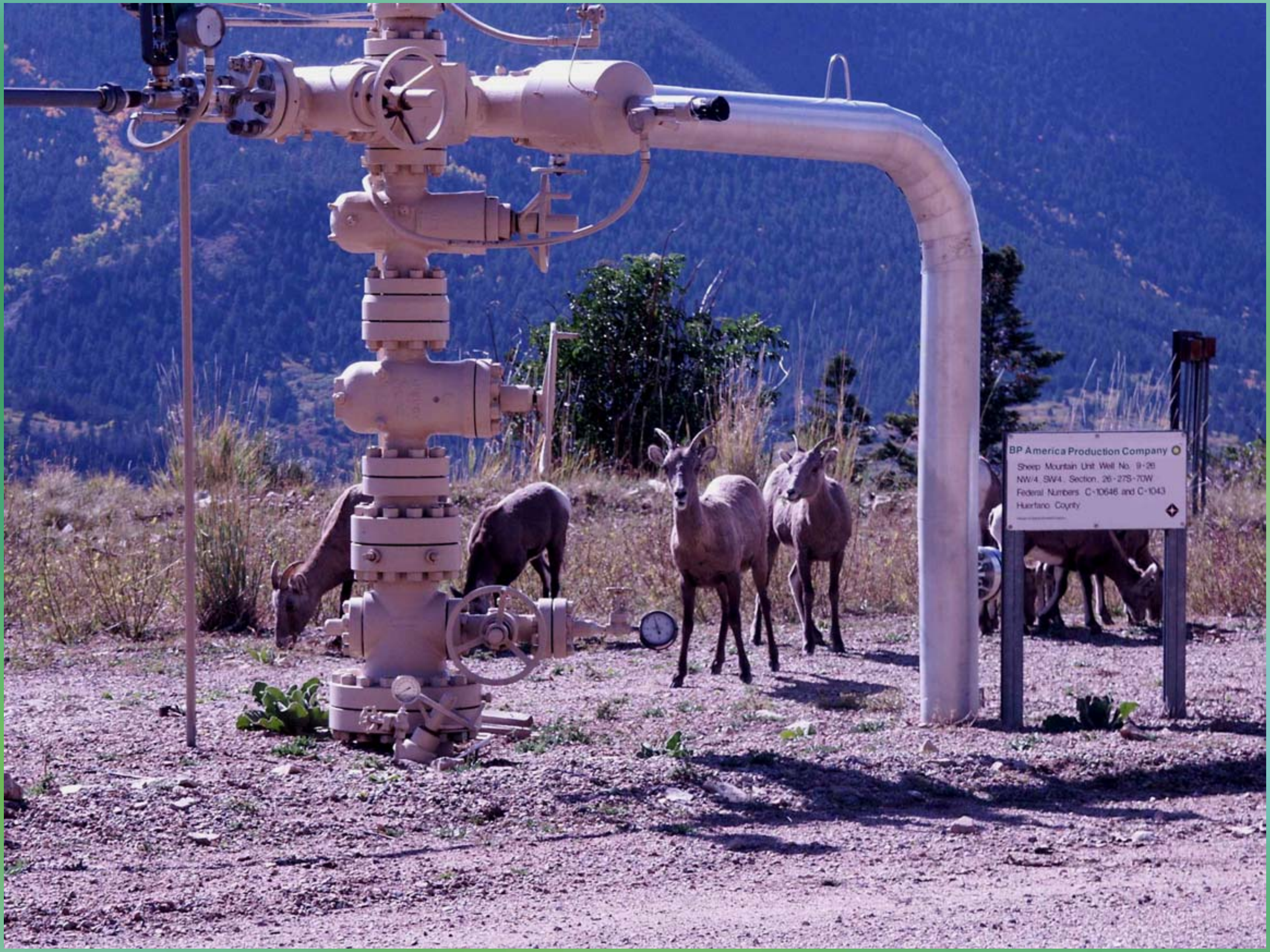
Celia, M.A. and S. Bachu, “Geological Sequestration of CO2: Is Leakage Unavoidable and Acceptable?”, *Proc. Sixth Intl. Greenhouse Gas Technologies Conference*, Kyoto, J. Gale and Y. Kaya (eds.), Volume I, 477-482, 2003.

WELLBORE INTEGRITY WORKSHOP – APRIL 2005

Sheep Mountain Unit presentation

SHEEP MOUNTAIN UNIT

SHEEP MOUNTAIN UNIT

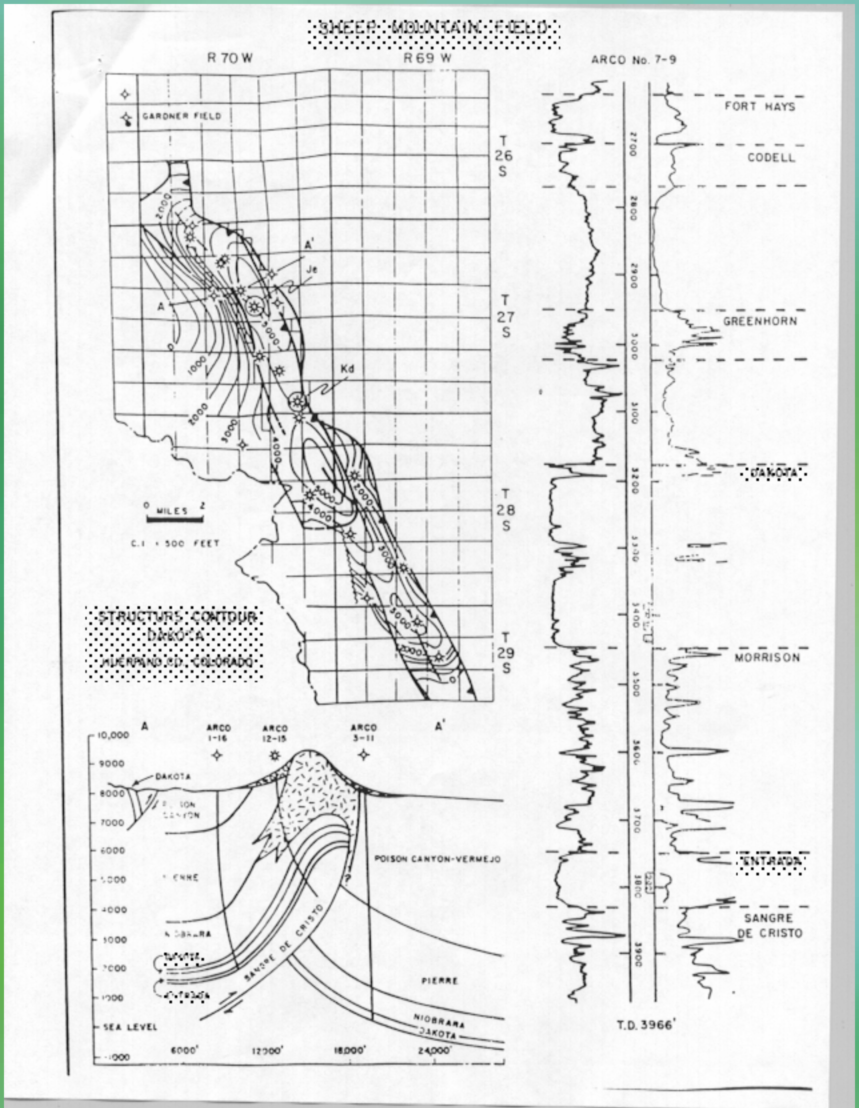


SHEEP MOUNTAIN UNIT

- **RESERVOIR CHARACTERISTICS**
  - DAKOTA ZONE 3400’ TVD
  - ENTRADA ZONE 3800’TVD
  - POROSITY 18%
  - PERMEABILITY 5 to 150 MD
  - RECOVERY 1.2 TCF

- **CURRENT PRODUCTION**
  - 54 MMCFPD
  - 96% CO_2

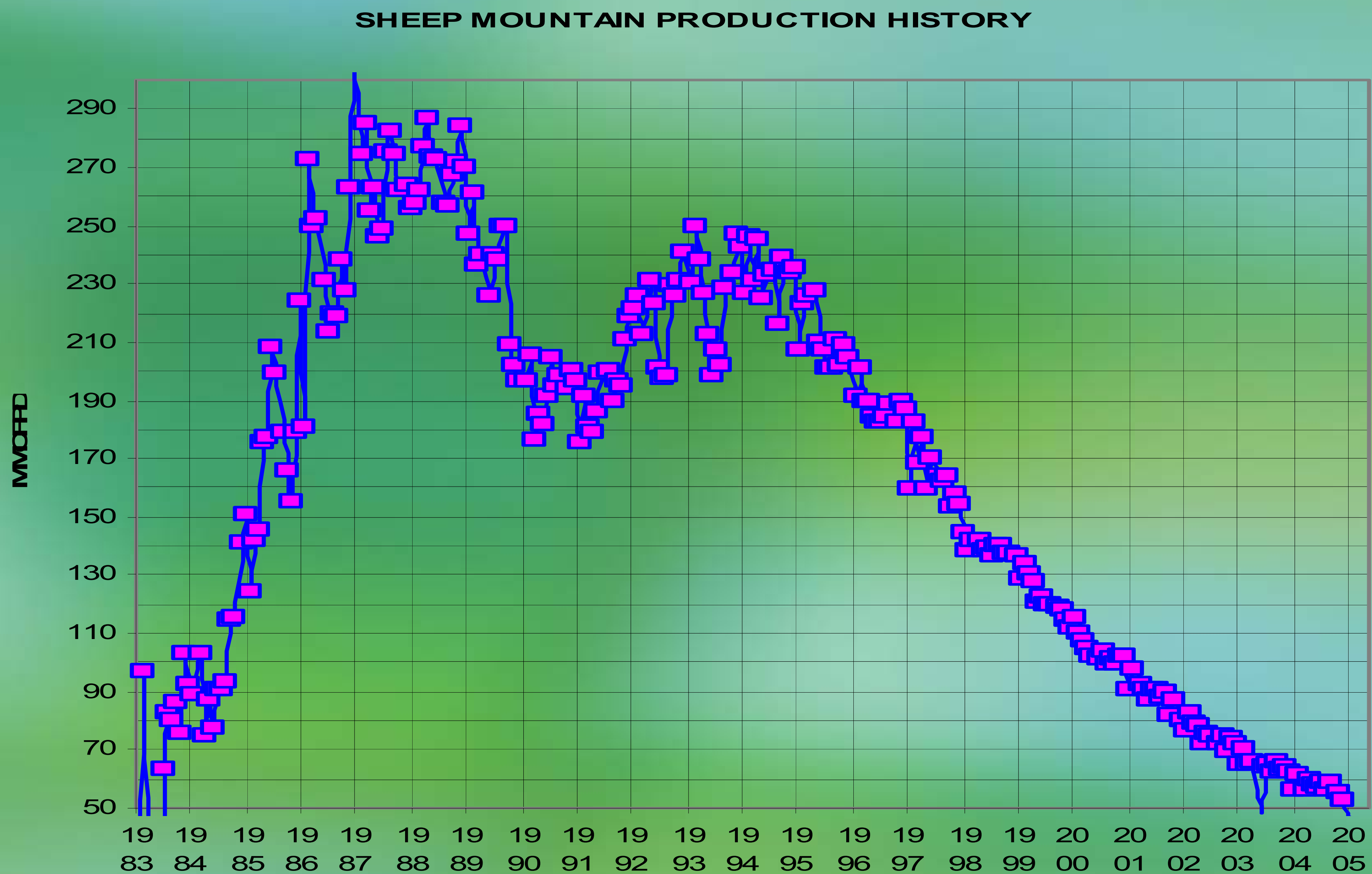
SHEEP MOUNTAIN - MAP



SHEEP MOUNTAIN UNIT

- **SMU OPERATION**
  - 5 DRILLSITES
  - 29 PRODUCING WELLS
  - 1 WWD WELL

SHEEP MOUNTAIN UNIT



SHEEP MOUNTAIN PIPELINE

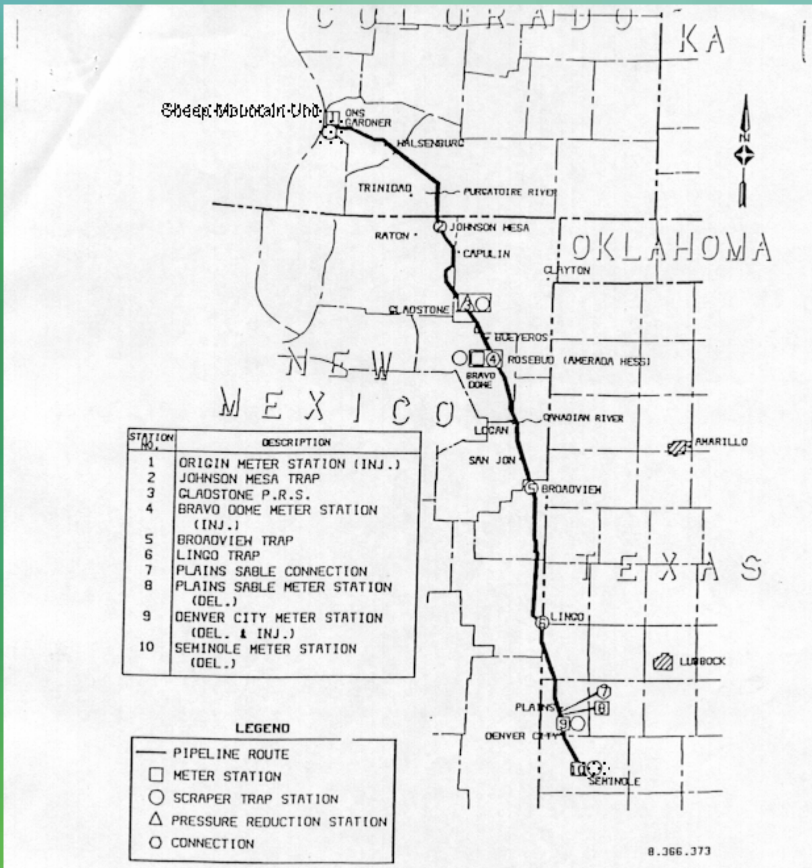
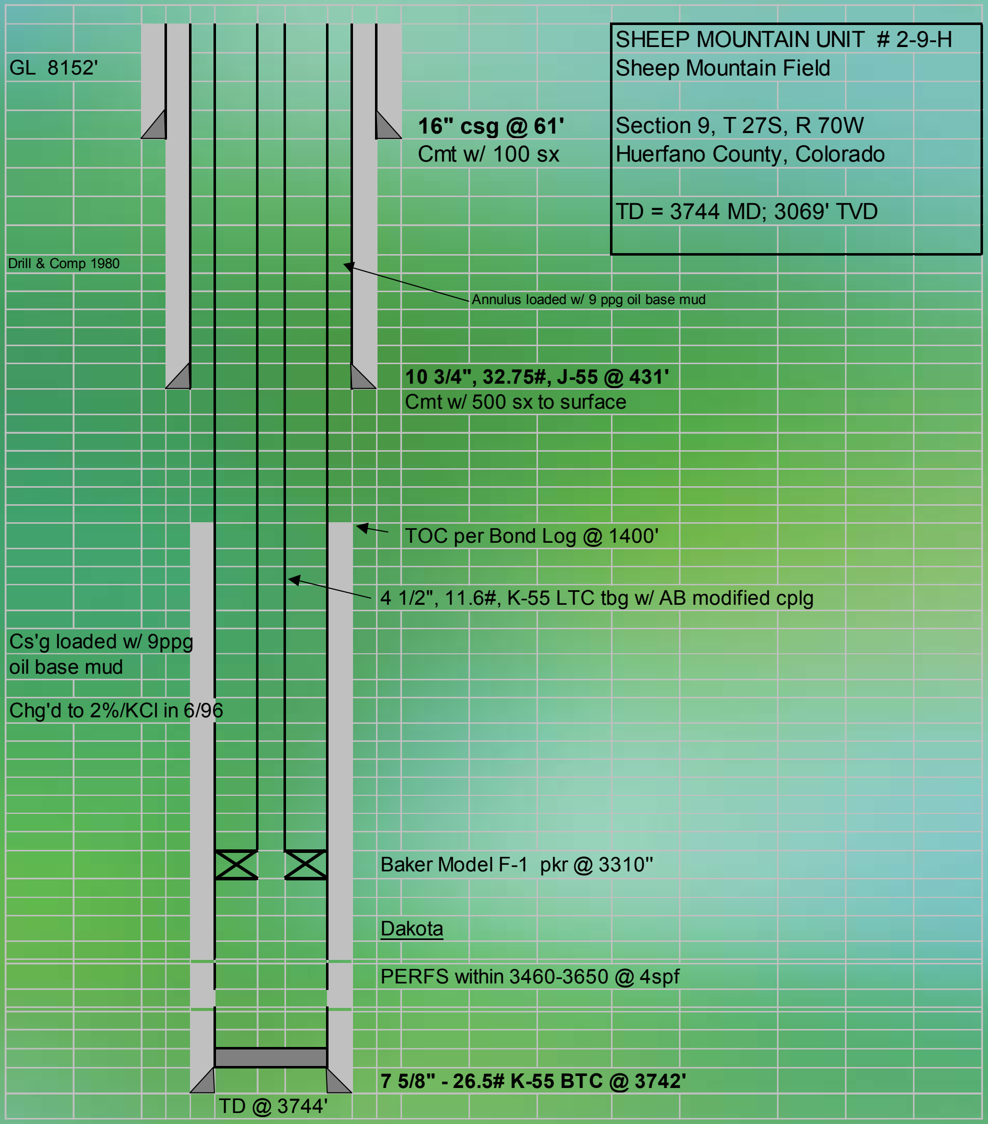


Figure A-1. Layout of Sheep Mountain CO_2 Pipeline

SHEEP MOUNTAIN PIPELINE

- **CARBON STEEL – CO_2 moisture < 25#/MMCF**
- **20" AND 24" DIAMETER**
- **WALL THICKNESS 0.438" to 0.625"**
- **OPERATING PRESSURE 1050 to 2500 psig**
- **408 MILES TO W. TEXAS**

SMU WELL SCHEMATIC



SMU WELL COMPLETION

- **SURFACE CASING 10 ¾”@ 1000’**
  - **CEMENTED w/ CLASS “H” with 2%CaCl and (1/4# flocele)**

- **PRODUCTION CASING 7 5/8”@ 3800’**
  - **CEMENTED w/ 500sks HLW, 10% salt, 10#/sk gilsonite followed by 200 sks Class “H” with 3/4% CFR2**
  - **Preflush with 1000gals. SAM4 and 500gals. diesel**

SMU WELL CORROSION ISSUES

- **TUBING LEAKS**
  - **PIN END CORROSION**
  - **BODY CORROSION (DEGRADED COATING AREAS)**
  - **WIRELINE CUTS IN COATING**

- **WELLHEAD CORROSION**
  - **MASTER VALVE RING JOINT GROOVE**
  - **GATE SEAL AREAS**
  - **TUBING HEAD**

SMU WELL WORK PROGRAMS

- **REPLACED TUBING 18 OF 29 WELLS (60%)**
  - **IPC with TK-99**
  - **EPDM SEAL RINGS**
  - **TUBOSCOPE SEAL LUBE ON THREADS**
  - **IMPROVED HANDLING OF TUBULARS**

    (IPC damage prevention)

- **WELLHEAD REPAIRS**
  - **TUBING HEAD REPLACEMENT ON 4 WELLS**
  - **MASTER VALVE REPLACEMENTS 8 WELLS (28%)**
  - **WING VALVE REPLACEMENTS 15 WELLS (52%)**

SHEEP MOUNTAIN UNIT

SHEEP MOUNTAIN UNIT

SHEEP MOUNTAIN UNIT

SHEEP MOUNTAIN UNIT

- **CASING INTEGRITY MONITORING**
  - **CASING ANNULUS PRESSURE**
  - **ANNULUS FLUID LEVEL MONITORING**
  - **GAS SAMPLE ANALYSIS (CO_2 VS METHANE)**
  - **CASING HYDROTEST @ WORKOVER**

- **WELLHEAD INSPECTION**
  - **VIDEO CAMERA**
  - **UT READINGS ON VALVE BODY**

Corrosion Resistant Cement for Carbonic Acid Environments

HALLIBURTON

$CO_2 + H_2O$ = carbonic acid

carbonic acid + Portland cement = no cement

A Well Documented Phenomena

- "Effects of CO_2 Attack on Cement in High-temperature Applications," paper SPE/IADC 18618 presented at the 1989 SPE/IADC Drilling Conference.
- "Carbon Dioxide Corrosion in Oilwell Cements," paper SPE 15176 presented at the 1986 Annual Meeting.
- "Natural CO_2—Rich Steam Heated Waters in the Broadlands-Ohaaki Geothermal System, New Zealand: Their Corrosive Nature," Geothermal Resources Council, Transactions, Vol 10.
- "The Long Term Sealing Capacity of Cemented Petroleum wells in a CO_2 Storage Project," SINTEF Petroleum Research Mid-term report, June 2002.

Conclusion

"Carbon dioxide corrosion of Portland cements is thermodynamically favored, and cannot be prevented."

Erik B. Nelson, Dowell Schlumberger in "Well Cementing," *Developments in Petroleum Science*, 28

Reactions Involved

$CO_2 + H_2O \rightarrow H_2CO_3$

$H_2CO_3 + \text{C-S-H} \rightarrow \text{silica gel} + CaCO_3$

$H_2CO_3 + Ca(OH)_2 \rightarrow CaCO_3 + 2H_2O$

$H_2CO_3 + CaCO_3 \rightarrow Ca(HCO_3)_2$

Solution

A non-Portland based cement

Calcium Phosphate Cement (ThermaLock®)

Developed in 1998 as a joint project between Toshifuma Sugama, Brookhaven National Laboratory, Lawrence Weber at UNOCAL, and Halliburton

Set Calcium Phosphate Cement

Does not contain:

- Calcium hydroxide
- Calcium silicate hydrates

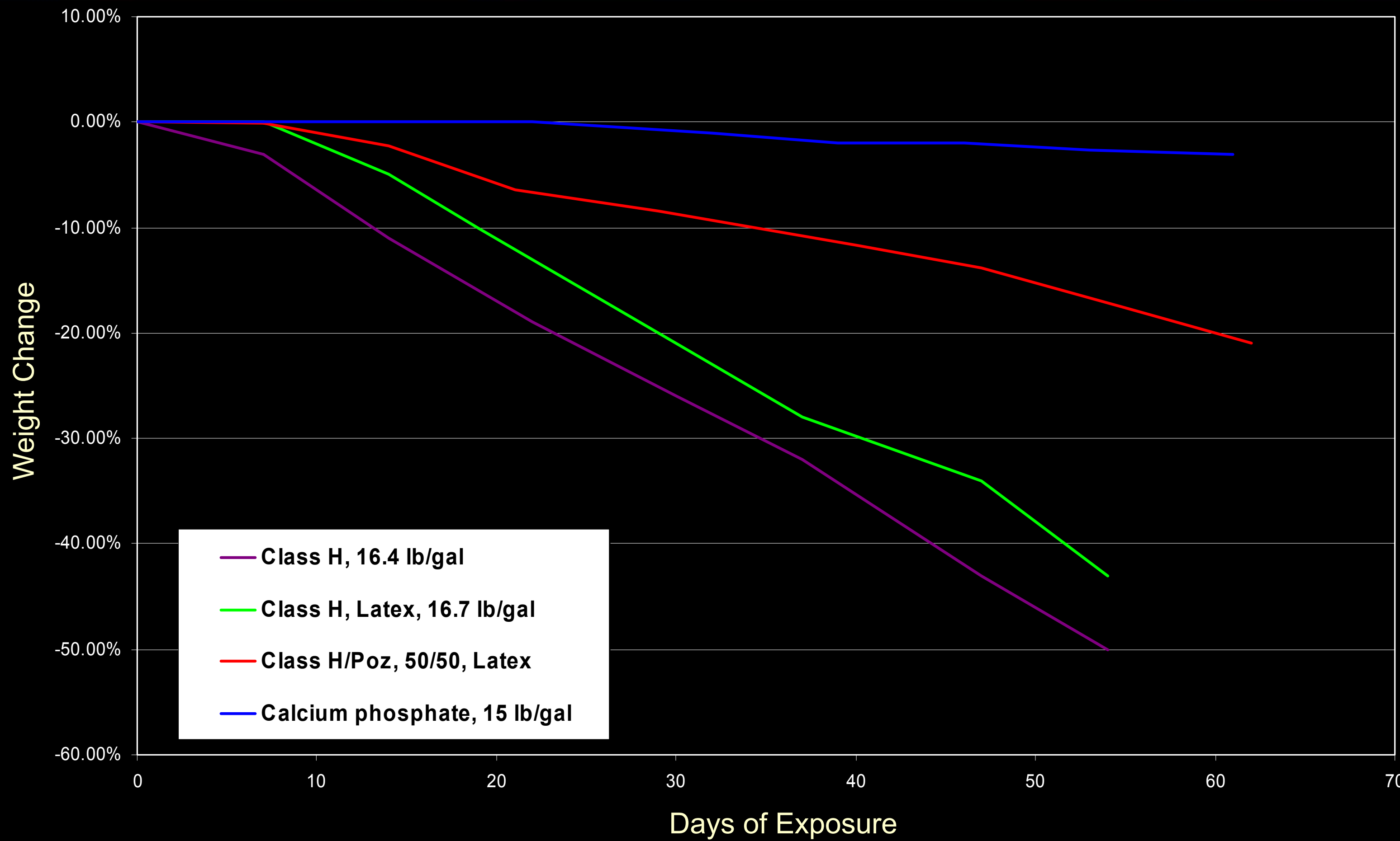
Does contain:

- Aluminate hydrates
- Calcium phosphate hydrates
- Mica-like calcium aluminosilicates

Calcium Phosphate Cement vs. Portland Cement

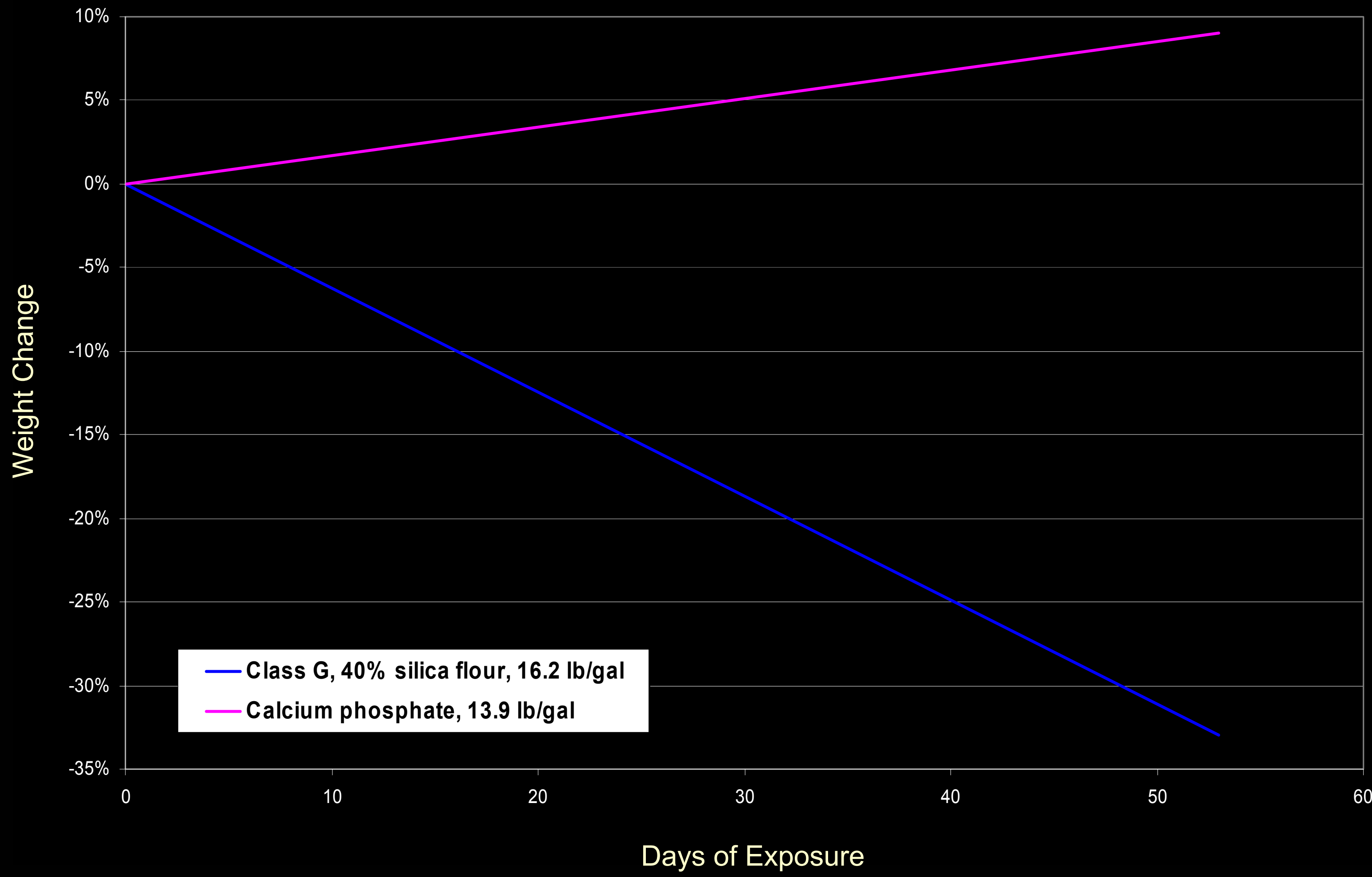
- Conditions: 140˚F, 1% aqueous Na_2CO_3 solution acidified to pH 2 with H_2SO_4 in a sealed chamber to generated CO_2
- Class H 16.4 lb/gal—50% weight loss in 54 days
- Class H, 2 gal/sk Latex, 16.7 lb/gal—43% weight loss in 54 days
- 50/50, class H/Poz, 2 gal/sk Latex—21% weight loss in 62 days
- Calcium phosphate 15 lb/gal—3% weight loss in 61 days

Calcium Phosphate Cement vs. Portland Cement in 140˚F 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

Calcium Phosphate Cement vs. Portland Cement in 500°F Carbonic Acid Solution



Visual Comparison of Calcium Phosphate Cement (left) and Portland Cement (right)

CO_2 deteriorates Portland cement over time while leaving calcium phosphate cement virtually unaffected.

Field Use of Calcium Phosphate Cement

- Geothermal in Indonesia, Japan, California
- P&A CO_2 injector in Oklahoma
- Steam injector wells in Kuwait and New Zealand
- Casing repair and liner completions for CO_2 flood field in Kansas
- Foamed for steam injectors in California
- 18,000-ft sour gas injector well in Wyoming
- Foamed for off-shore use in North Sea

Character of the Well-Bore Seal at 49-6 in the SACROC Reservoir, West Texas

Bill Carey, George Guthrie, Peter Lichtner, Rajesh Pawar

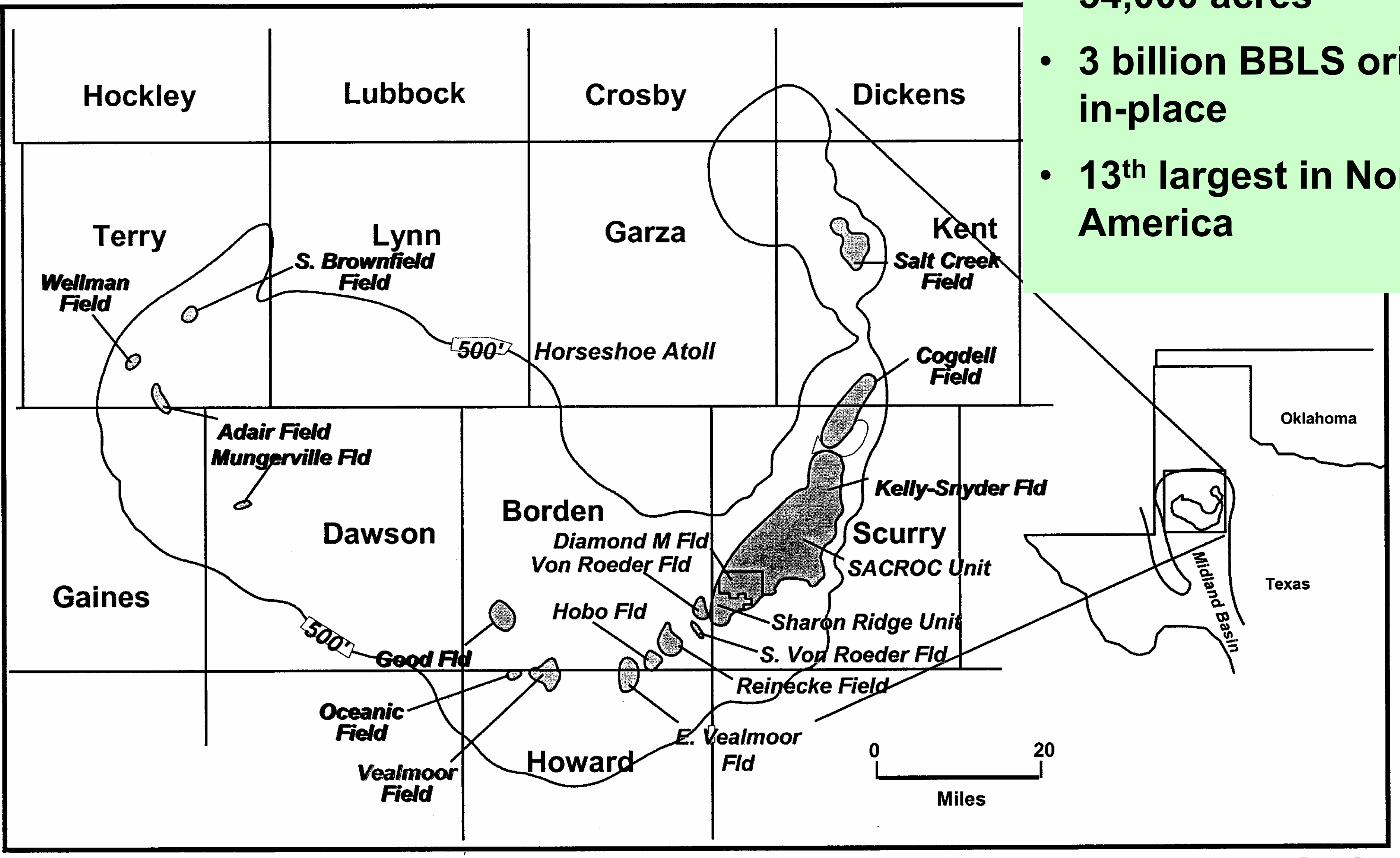
Los Alamos National Laboratory

Scott Wehner, Mike Raines

Kinder Morgan CO_2

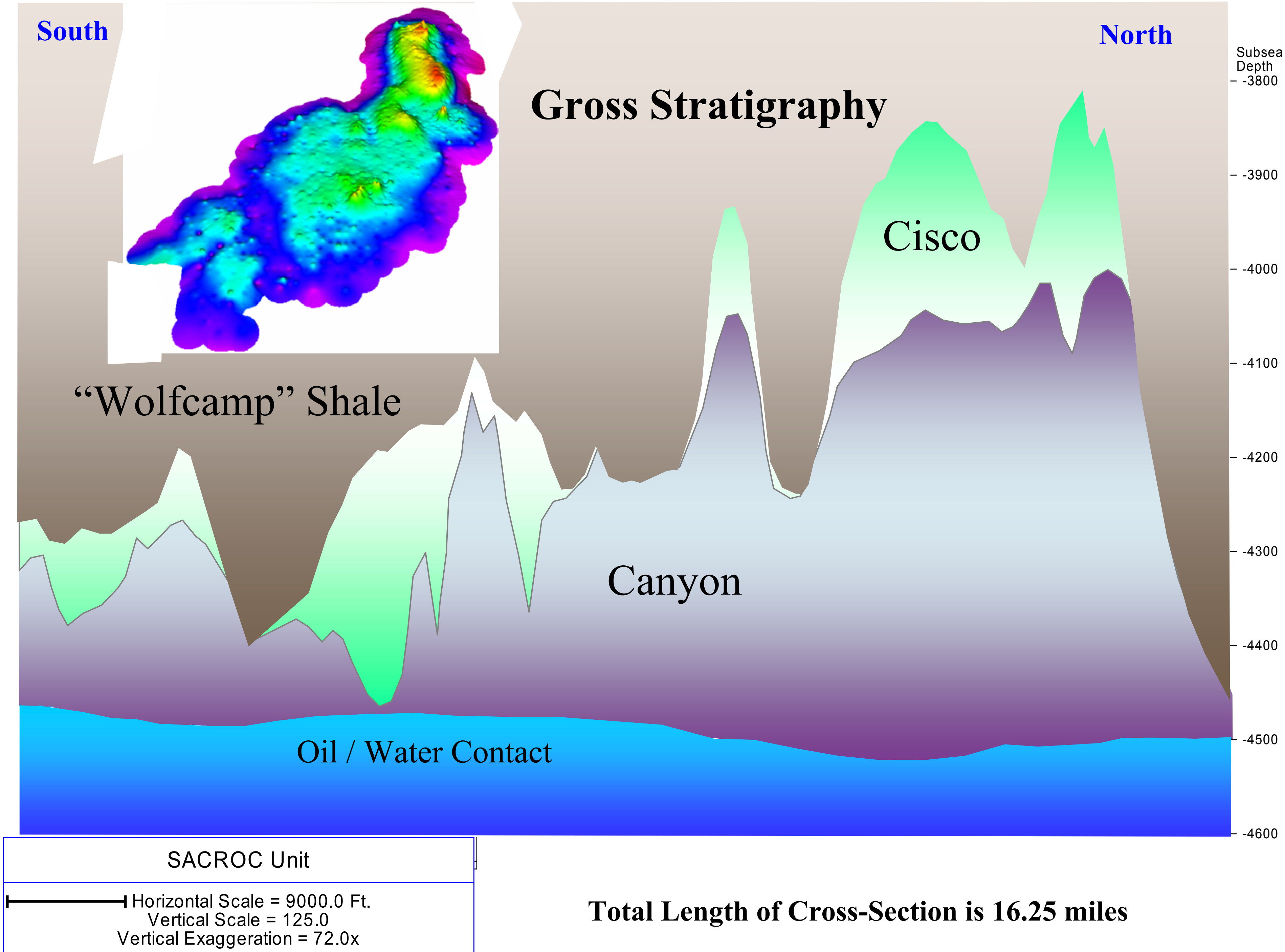
Field Studies: SACROC Overview

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



KINDER MORGAN CO₂ COMPANY, L.P.

Los Alamos NNSA National Nuclear Security Administration

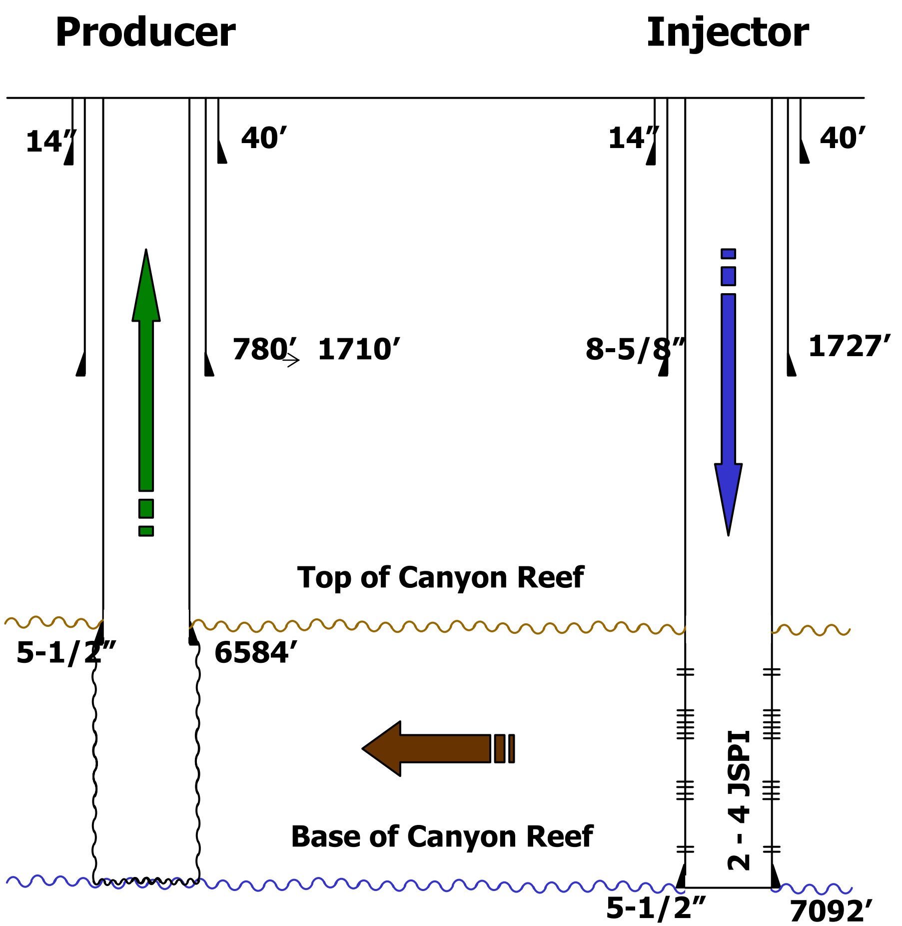

South
North
Gross Stratigraphy
Subsea Depth
-3800
-3900
-4000
-4100
-4200
-4300
-4400
-4500
-4600
Cisco
"Wolfcamp" Shale
Canyon
Oil / Water Contact
SACROC Unit
Horizontal Scale = 9000.0 Ft.
Vertical Scale = 125.0
Vertical Exaggeration = 72.0x
Total Length of Cross-Section is 16.25 miles

SACROC
(Scurry Area Capital Reef Operations Committee)

- 81 mi^2, 1800 wells, 600 operational
- Productive zone at 7000' and is as thick as 800'
- Field temperature 50 ºC; Initial pressure 3200 psi (now 2600 psi)
- CO_2 flooding initiated 1972 (only one field in the world is older)
- CO_2 now obtained primarily from McElmo Dome, CO
- 62% of all CO_2 injected is not recovered (effectively sequestered)
- Drilling and production from zones above and below the Cisco/Canyon Reef complex have been free of CO_2

SACROC Study Goals

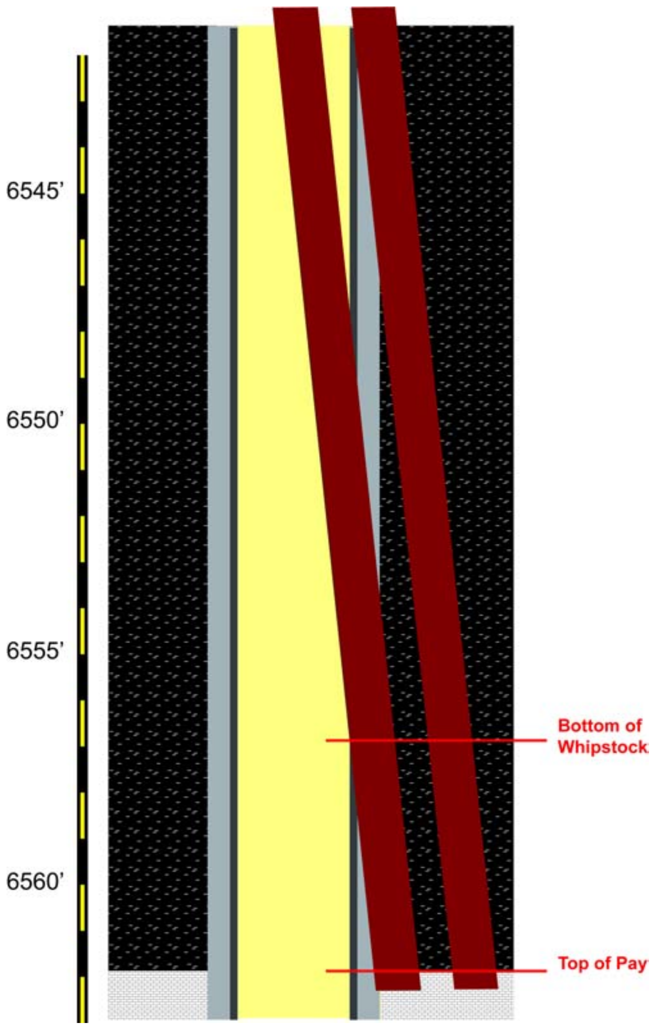
- Determine long-term effects of CO_2 on casing, cement, and shale
- Conduct detailed studies of critical interfaces: casing/cement, cement/shale, and shale/limestone
- Focus on changes in mineralogy, hydrologic properties, and mechanical properties
- Obtain sidetrack cores from existing injection wells (have experienced slugs of high-pressure CO_2) and producer wells (have experienced CO_2-saturated brine and oil).
- Obtain core from new drilling operations

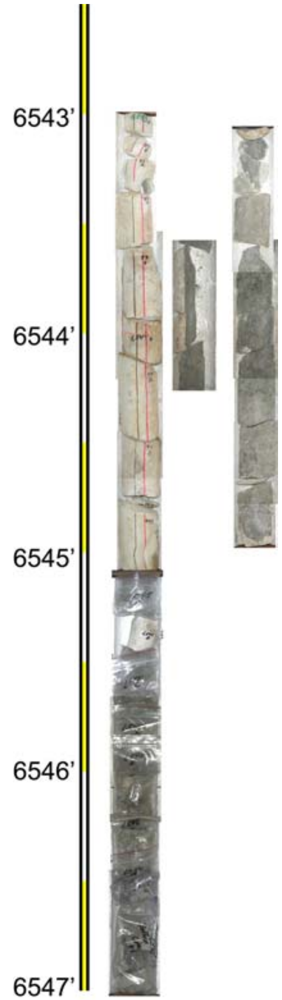


Potential Effects of Carbonation

- 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

Sacroc Core: 49-6 Producer/Injector





Drilled 1950
First CO_2 exposure 1975
Years of CO_2 operation: 17
Amount of CO_2 produced/injected:
2.2 Bscf

SACROC Core: 49-5, Producer

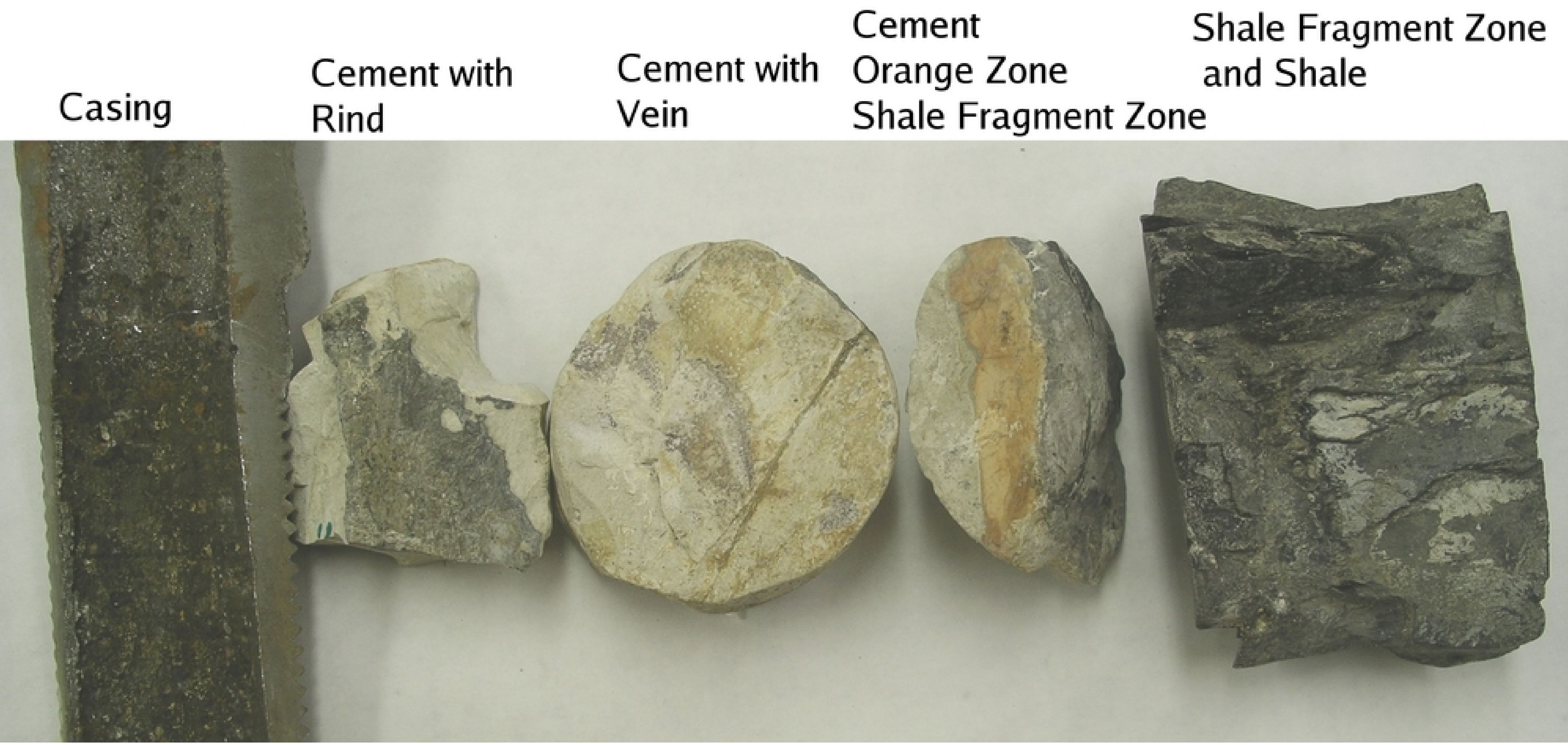
Drilled ~1950
First CO_2 exposure 1974
Years of CO_2 operation: 21
Amount of CO_2 produced: 0.33 Bscf

Limestone-Shale Contact in 49-5

Phase	Limestone
Calcite	Predominant
Ankerite	Minor
Quartz	Minor

Phase	Dark lenses
Illite	n.a.
Calcite	n.a.
Ankerite	n.a.
Quartz	n.a.
Chlorite	n.a.

Cross-Section Through Well-Bore: 49-6



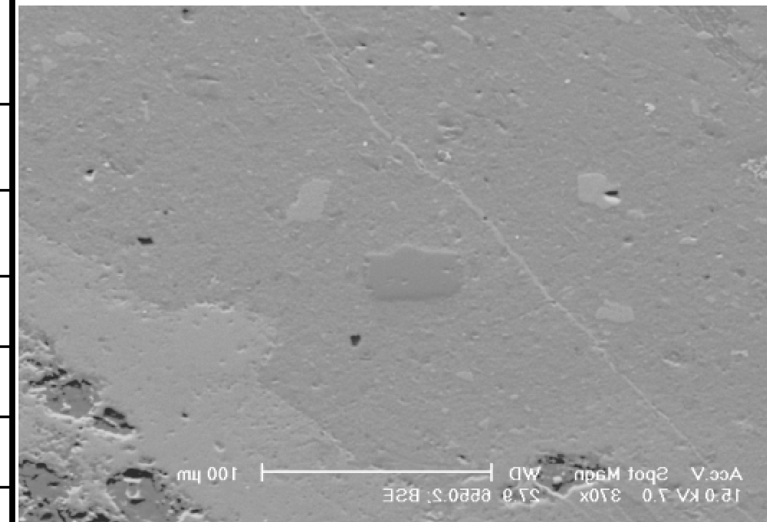
Casing and Casing Rind

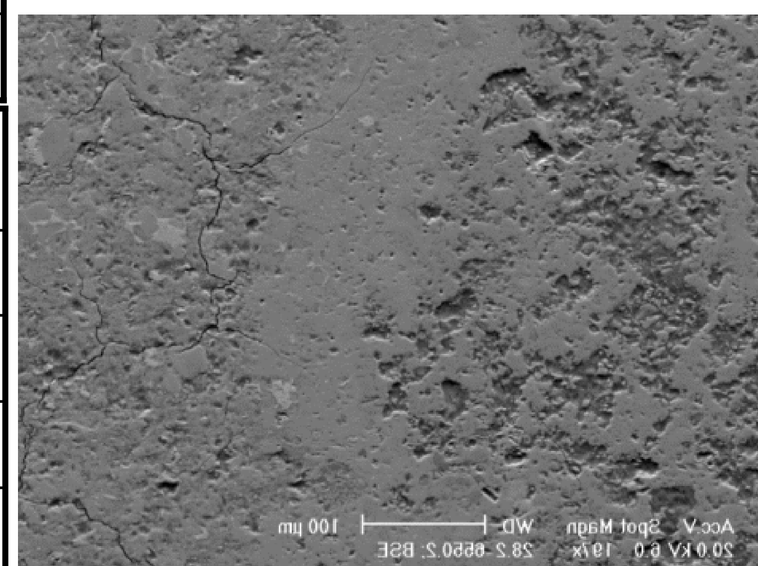
Phase	Casing Rind
Aragonite	60.3%
Calcite	24.0%
Halite	14.3%
Quartz	1.4%

Gray Cement – Orange Zone – Shale Fragment Zone

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%

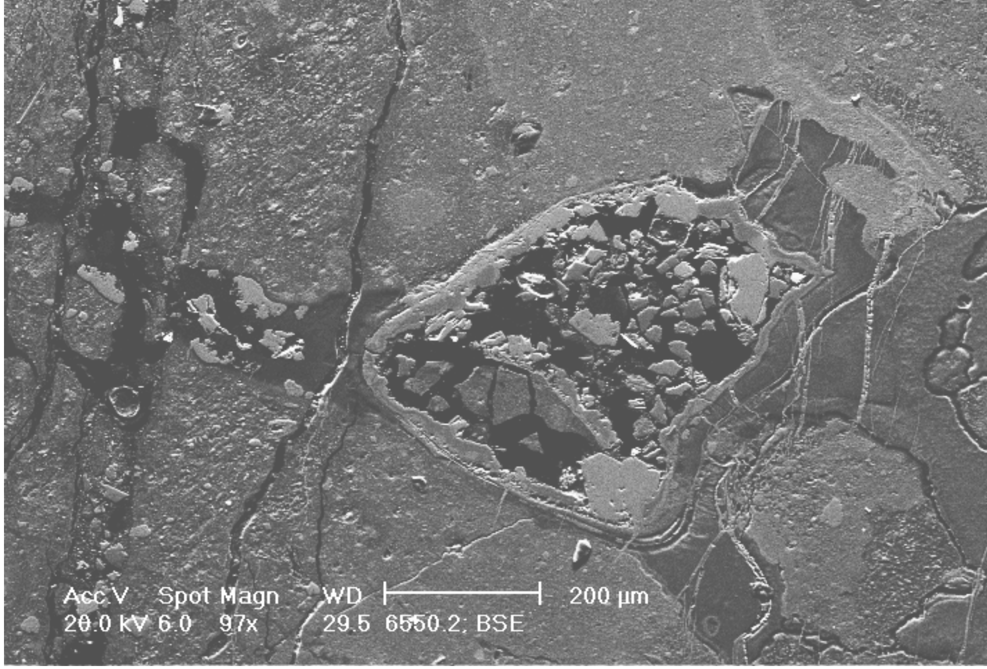
Phase	Orange Zone
Calcite	44%
Aragonite	8%
Vaterite	33%
Halite	13%

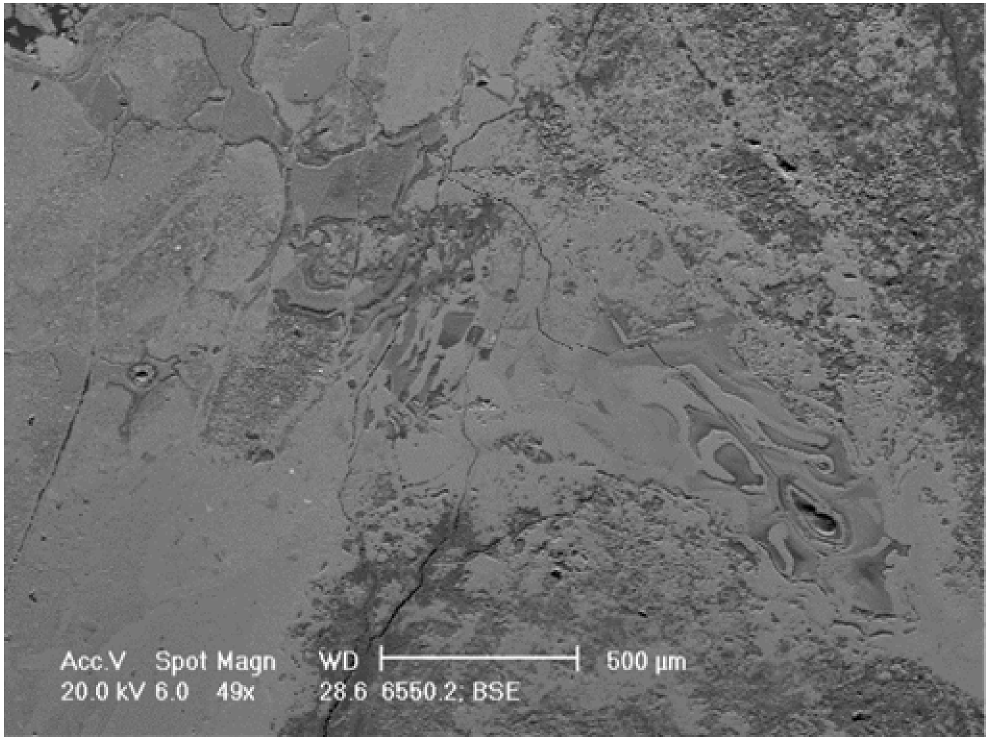




Shale Fragment Zone

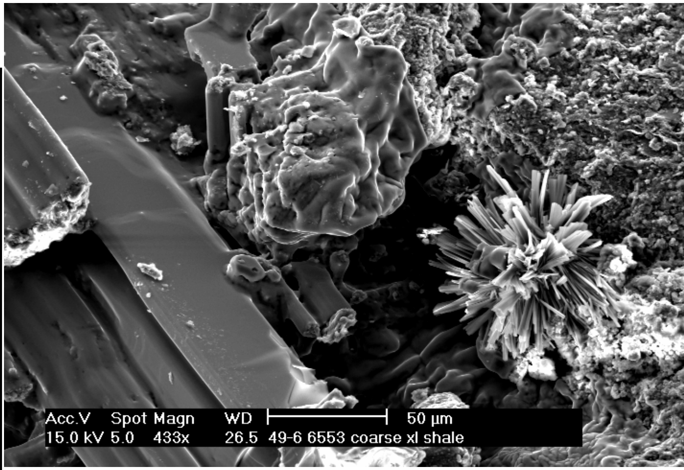
Mineralogically a mixture of shale and orange-zone

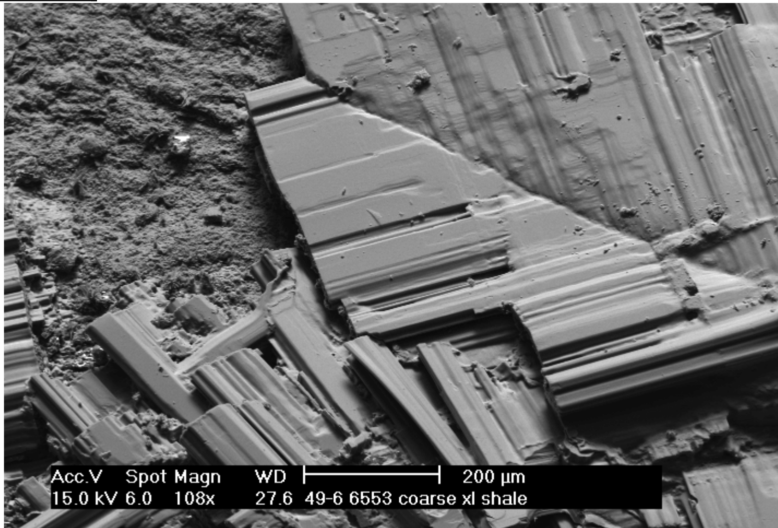




Shale

Mineral	
Illite	57.5%
Quartz	26.0%
Mica	7.7%
Plagioclase	5.0%
Pyrite	1.8%
Chlorite	0.9%
K-Feldspar	0.8%





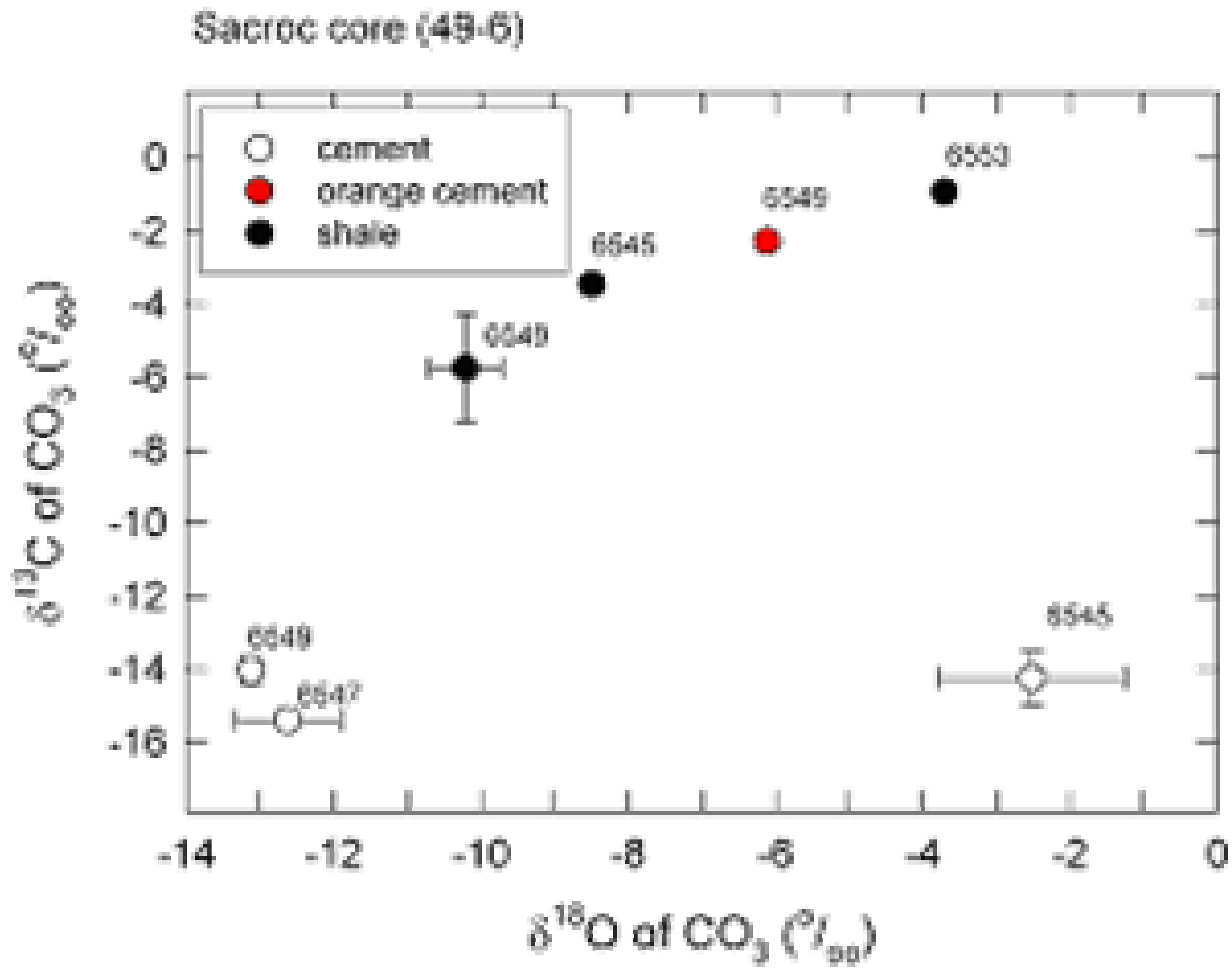
Cement-Limestone Contact 1000’ Above Pay

Phase	Cement
Amorphous	Major
Quartz	13%
Calcite	17%
Portlandite	5%
Katoite	7%
Brownmillerite	22%
Friedel’s Salt	2%
Ettringite	7%
Larnite	22%
$Ca_2SiO_4.H_2O$	5%

Origin of Orange Zone

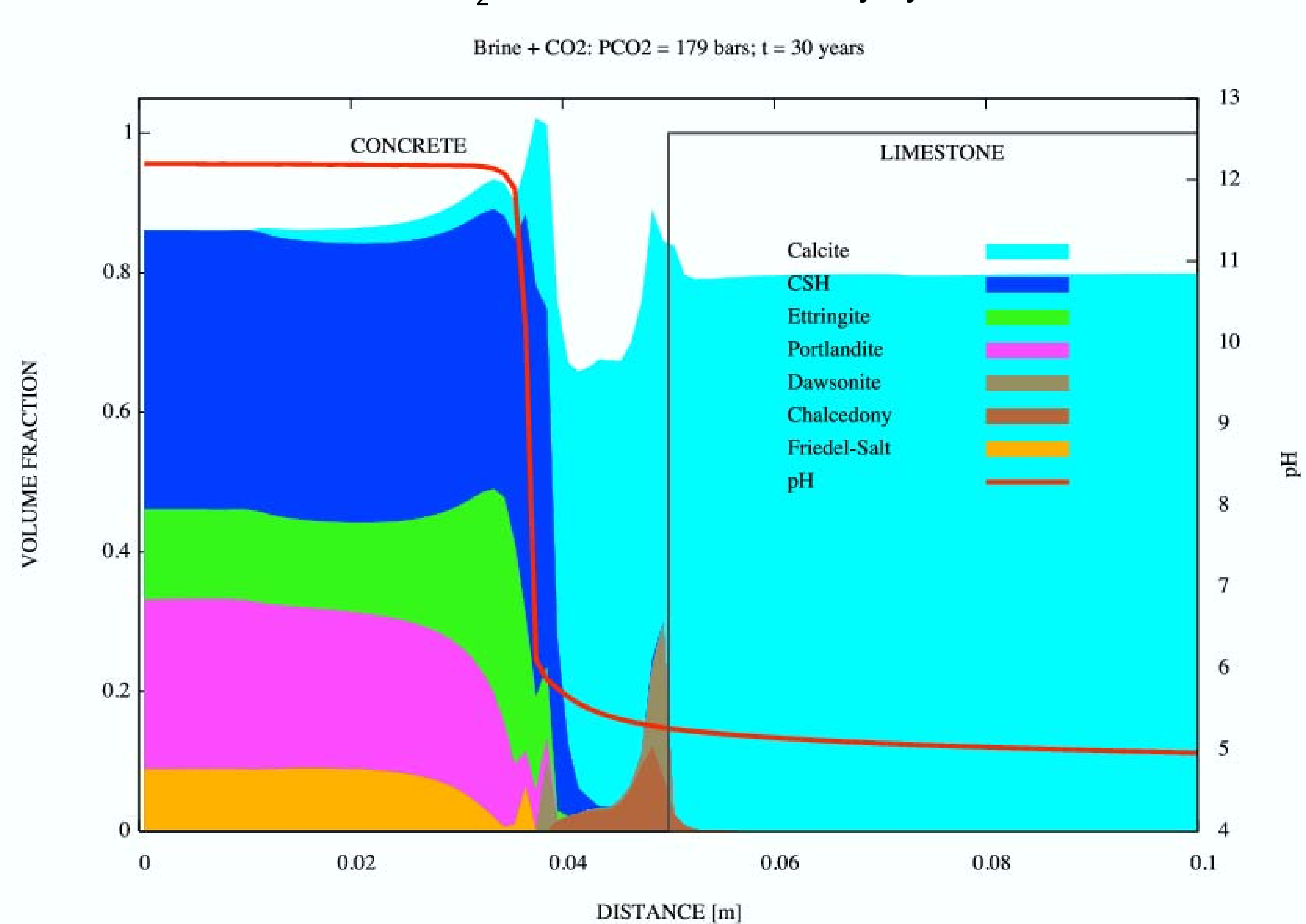
- Altered (carbonated) cement
- Abundant calcite, vaterite, and aragonite
- Amorphous component: Al-Si silicates with Na derived from brine
- Difference in presence or absence of portlandite indicates effective chemical separation of the orange zone and the cement
- Isotopic studies show that the carbonate in the orange zone and cement are distinct
- Orange zone may reflect diffusion of CO_2 and formation of a reaction front with the remaining cement
- Orange color may not reflect oxidation/reduction so much as decomposition of AFm phases and precipitation of ferric hydroxides

Stable Isotope Studies of Core Samples



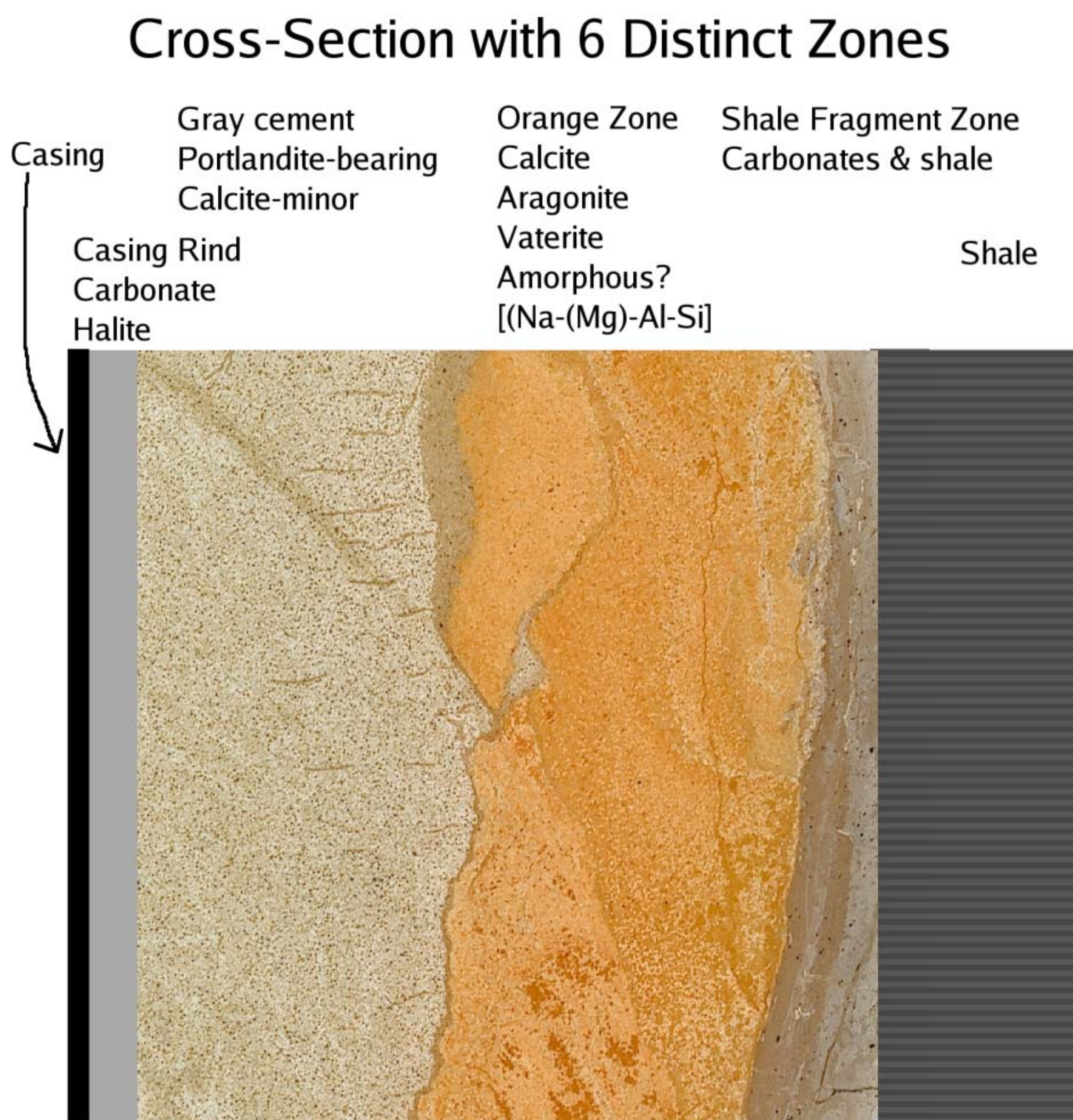
Reactive Transport Modeling: Carbonation Front

1-D Diffusion of CO_2-saturated brine into fully hydrated cement



Composite "Section" Observation Summary

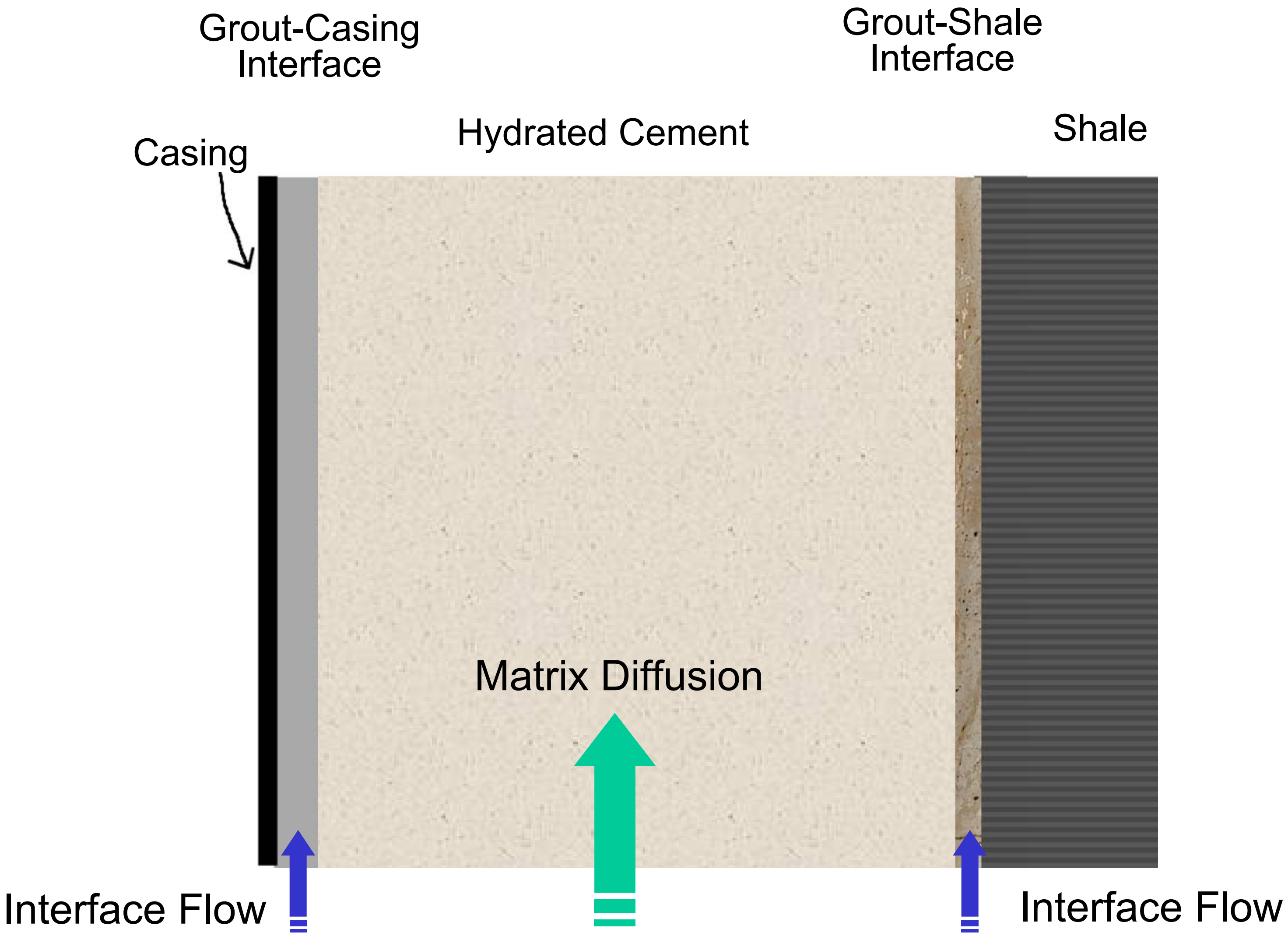
- Cement recovered: retains structural integrity
- Shale-cement interface not preserved: low bond quality?
- Limestone-cement interface preserved: high bond quality
- A thick carbonated zone occurs between cement and shale
- Shale fragment zone contains carbonate and "mobile" silica
- Gray cement contains portlandite [$Ca(OH)_2$]
- Gray cement contains calcite veinlets
- A carbonated rind exists between the cement and casing



Conclusions

- EOR sites have tremendous potential for evaluating feasibility of CO_2 sequestration
- Need to pay just as much attention to the cement/casing that is absent as the core that can be recovered
- Recovery of core at SACROC and from the Tensleep Formation demonstrate that cement can retain integrity for decades
- CO_2 does attack cement but there are stages of carbonation that precede and help prevent mechanical failure
- Experimental studies of the carbonation process are necessary to interpret the observed textures
- Numerical modeling is helpful in understanding processes and time-scales of implied by the observed mineralogy and texture

Potential Pathways for Well-Bore CO_2 Migration



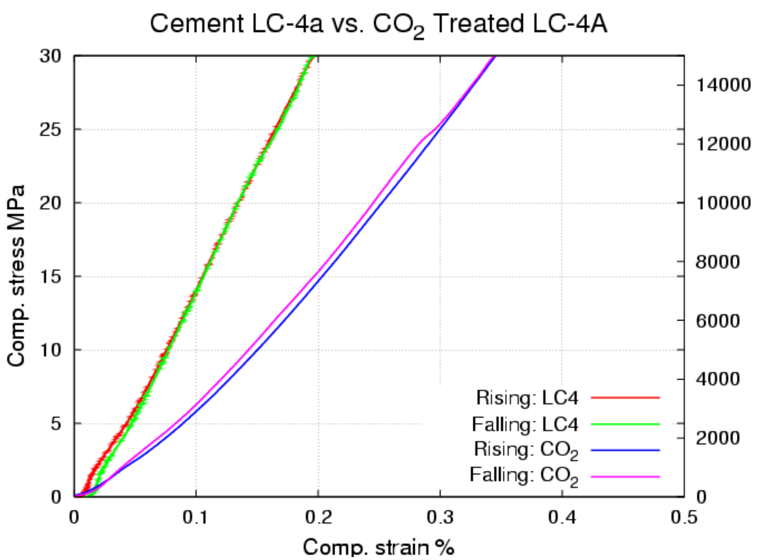
Preliminary Hypotheses on CO_2 Mobility at the Well-bore Interface

- **Possible origins of calcium carbonate**
  - Injected CO_2 (light or heavy carbon)
    - Diffusing through cement
    - Migrating along casing-cement interface
    - Migrating along cement-shale interface
    - Migrating along cement fractures
    - Escaping through casing joints or corrosion zones
  - Diffusing bicarbonate from formation waters (heavy carbon)
- **Possible origins of orange zone**
  - Altered (carbonated) cement
  - Altered (carbonated) drilling mud
  - Deposition zone of carbonate-rich fluids (fracture filling)
- **Possible origins of shale-fragment-zone**
  - Side-wall paste of rock fragments and drilling mud or cement

Preliminary Observations

- **Presence of structurally competent cement (and orange zone) precludes inundation of well-bore contact zone with circulating, CO_2-rich fluids**
- **Presence of calcium carbonate indicates some CO_2 mobility**
- **Presence of portlandite in cement indicates incomplete carbonation**
- **CO_2 pathways appear along the casing-cement interface and the cement-shale interface**
- **Amount of CO_2 moving along these interfaces unknown**
- **Point of origin of CO_2 moving along these interfaces unknown**

- **Experimental work is key to interpreting field observations and constraining modeling results**
- **Critical role of cement water saturation on carbonation rate**



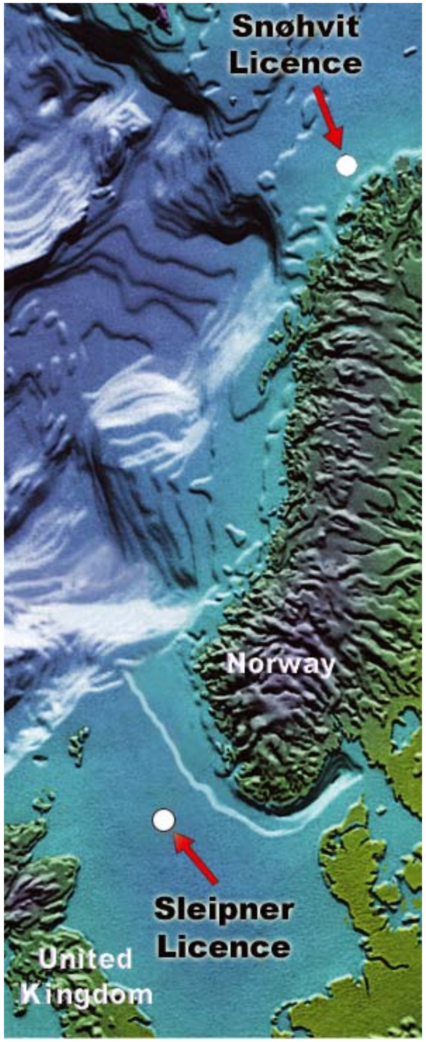
PERMANENT CO2 - STORAGE

Dr.-Ing. Tor Harald Hanssen

Permanent CO_2 storage facilities

- Sleipner in the North Sea
- Snøhvit in the Barents sea, shipped to Cove Point US
- In Salah, Algeria with BP and Sonatrac

Sleipner and Snøhvit location

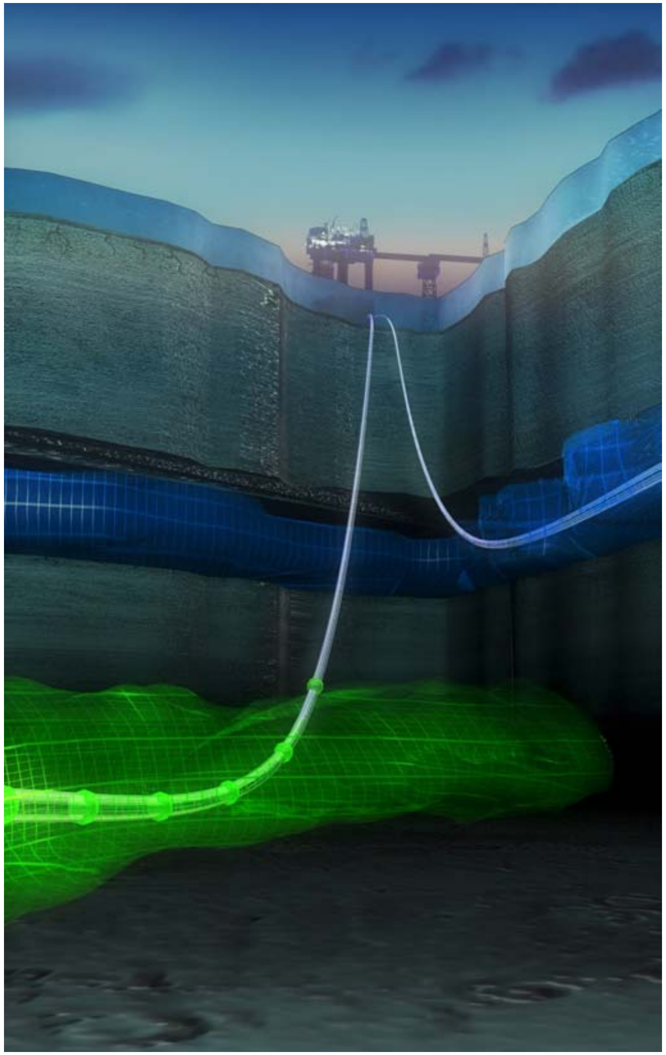


- Sleipner in operation for more than 10 years
- Snøhvit is being developed, CO2 deposition well drilled Jan 05

Sleipner platform

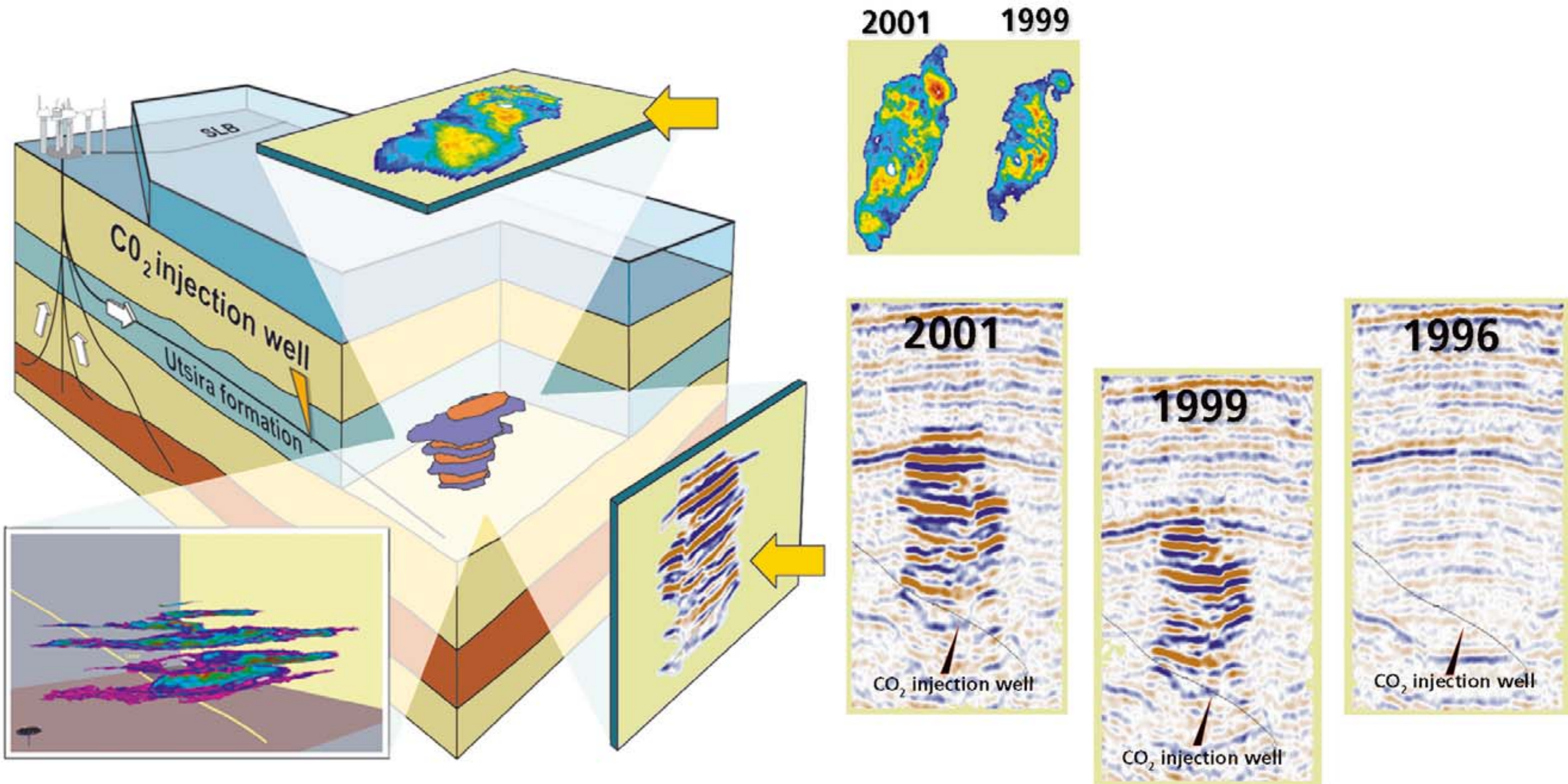
- Producing condensate and gas
- Exporting gas
- Drilling new wells

Sleipner production and injection

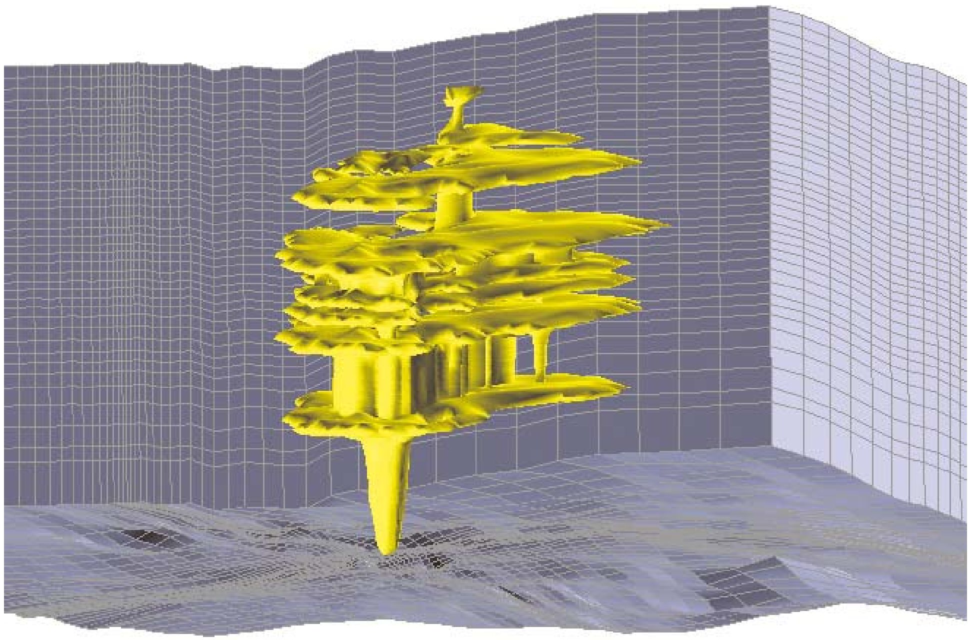


- Injection 3km away from producing wells

Sleipner injection

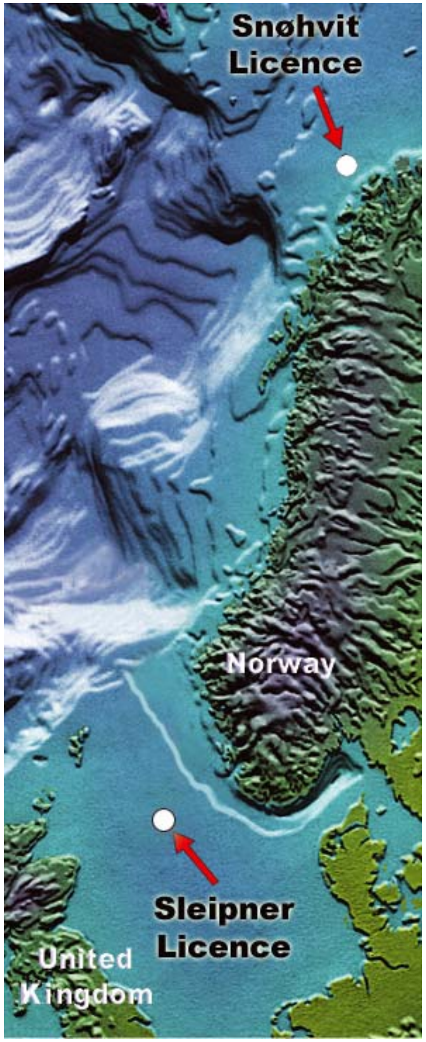


Utsira CO2 gas plume



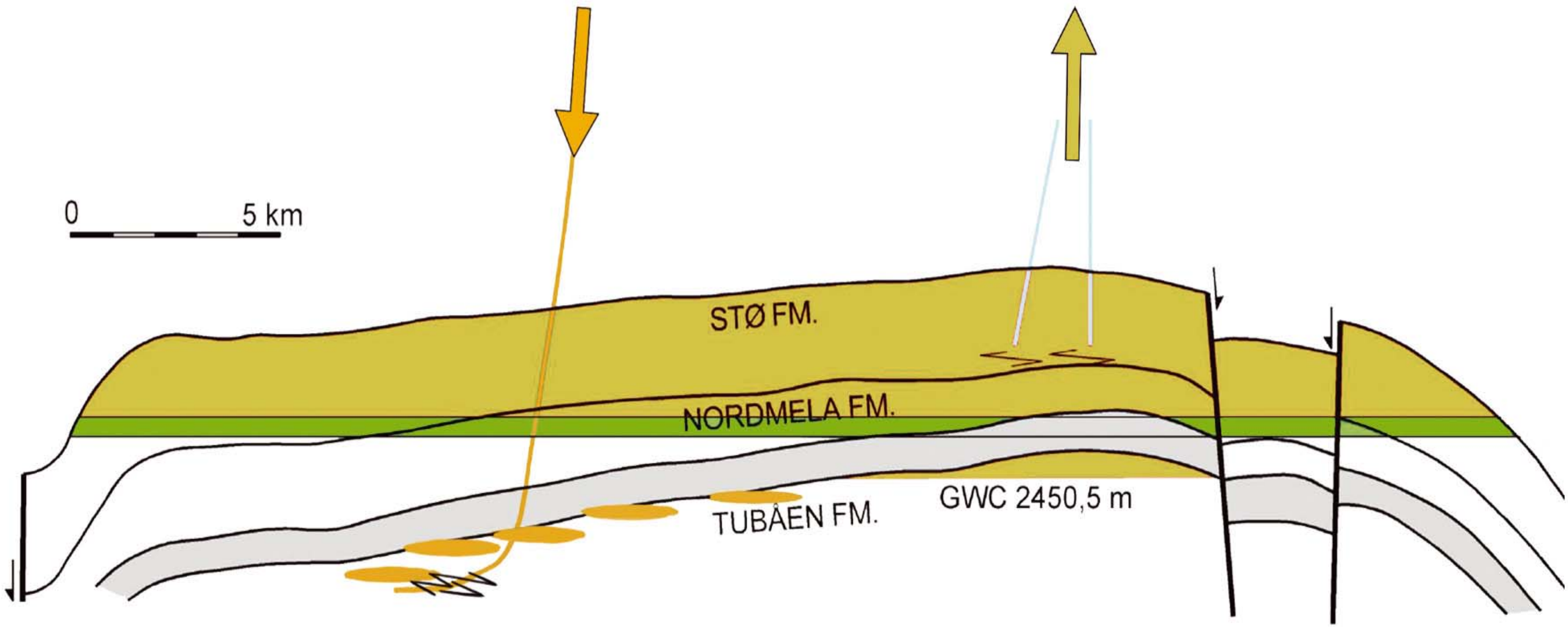
- Gas migration stepwise
- Overcomming retention pressure
- Now at the top level

Sleipner and Snøhvit location

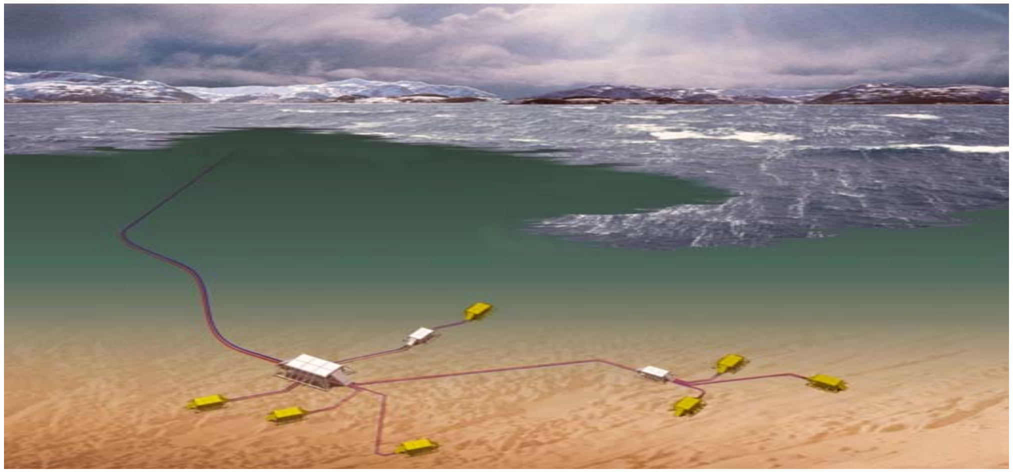


- Sleipner in operation for more than 10 years
- Snøhvit is being developed, CO2 deposition well drilled Jan 05

Snøhvit e-w panel

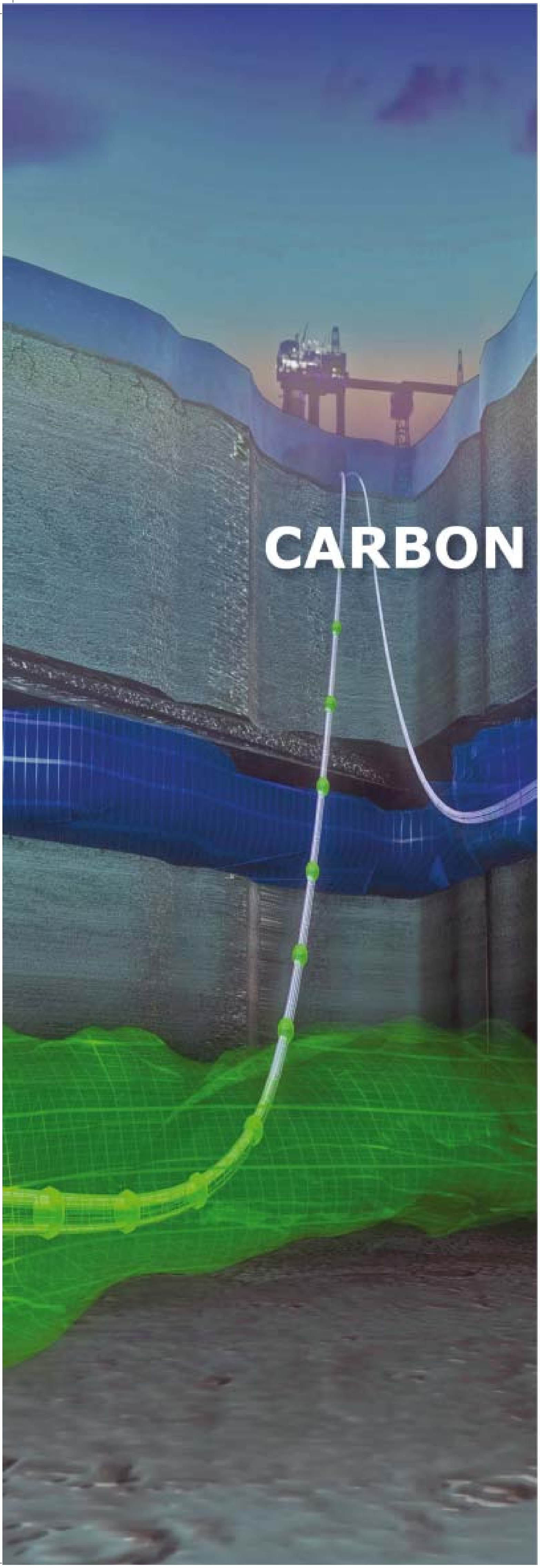


Snøhvit subsea structures



- Intense drilling campaign
- All facilities on land
- 150 km subsea flowline, service line and communication line

Research & Technology
Memoir No. 5



CARBON DIOXIDE

Capture, Storage and Utilization

STATOIL

MEMOIR SERIES

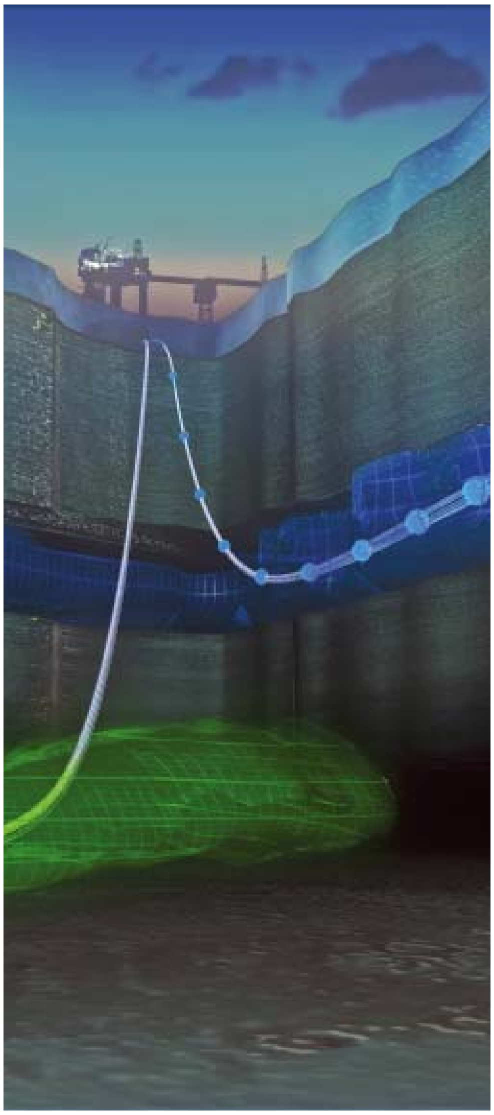
This R&D Memoir Series summarizes cumulative achievements made by Statoil researchers and their associates in key technical areas: care is thus taken to differentiate between achievements made by Statoil alone and those resulting from external cooperation. The intended readership is anyone with a technical overview of the petroleum industry. No specialist knowledge of the subject is required.

Other titles in this series are:
Memoir 1 – Flow Assurance
Memoir 2 – Offshore Geophysical Methods
Memoir 3 – Offshore Produced Water Management
Memoir 4 – Geological Reservoir Characterization

CONTENTS

ABBREVIATIONS

BGS:	British Geological Survey
BGR:	Bundesanstalt für Geowissenschaften und Rohstoffe
BRGM:	Bureau de Recherches Geologiques et Minieres
CASTOR:	CO_2 Capture and Storage Project
CCP:	CO_2 Capture Project
EBI:	Energy and Biodiversity Initiative
ENCAP:	Enchanced Capture of Carbon Dioxide project
GEUS:	Geological Survey of Denmark and Greenland
IEA:	International Energy Agency
IFP:	Institut Français du Petrole
IMN :	Industrikraft Midt-Norge AS
IPIECA:	Intern. Petrol. Industry Environmental Conservation Assoc.
IOR:	Improved Oil Recovery
LNG:	Liquefied Natural Gas
LPG:	Liquefied Petroleum Gas
NERC:	Natural Environment Research Council (UK)
NGU:	Norwegian Geological Survey
NITG-TNO:	Netherlands Institute of Applied Geoscience (TNO)
NTNU:	The Norwegian University of Science and Technology
PEL:	Progressive Energy Limited
SACS:	Saline Aquifer CO_2 Storage Project
SINTEF:	Foundation for Scientific and Industrial Research at NTNU



Front cover: cartoon of natural hydrocarbon gas being produced from the Sleipner gas field. Above: captured carbon dioxide being pumped into the overlying Utsira Formation for long-term storage. (Illustrations: Alligator Film/BUG.)

ACKNOWLEDGEMENTS

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INTRODUCTION

Cost-effective carbon dioxide capture, storage and utilization are essential elements in reconciling the use of fossil fuels with environmental protection.

Climate change

Carbon dioxide gas (CO_2) is a natural, fluctuating component of the Earth's atmosphere and has been present throughout most of geological time. However, since the industrial revolution the concentration has risen by about a third (from 280 to 370 parts per million) and may well reach at least twice the pre-industrial level by 2100.

Most of this increase is attributed to the burning of carbon-rich fossil fuels – coal, natural gas and oil – and is widely thought to be a contributory factor in trapping heat radiating from the earth's surface. This, in turn, may lead to global warming – the greenhouse effect – and stimulate climate change. To what extent this may happen is not known: some say it will lead to disastrous consequences while others foresee relatively slight but noticeable variations. Either way, something has to be done about it.

The obvious answer is to increase energy efficiency and rapidly convert to alternative energy sources, such as solar and wind power. But this is easier said than done. Switching to alternative sources will be a gradual process, because about 85% of the world's present energy needs are being met by plentiful and relatively inexpensive fossil fuels. In contrast, non-fossil fuel energy sources are expensive, and onshore renewables need large land areas to produce even modest quantities of power (e.g. windmill parks).

A more pragmatic approach is to stabilize atmospheric concentrations gradually at or below 550 parts per million. But this too is an enormous challenge, requiring a fifty per cent reduction in CO_2 emissions from projected levels by 2050. New technologies are therefore needed to lower the cost of alternative energy sources, strengthen the removal and storage of CO_2 from today's fossil-fuelled industries, and replace oil and coal by less carbon-intensive natural gas. Nevertheless, this is the more attractive proposition as it promises to allow present fossil-fuel industries and fossil-fuel rich countries to continue operating profitably while giving time for alternative energy sources to realistically come to the fore.

Statoil and climate policy

For Statoil the issue is not whether the world faces a climate problem or how severe it may be, but how harmful emissions may best be overcome. The Kyoto protocol is therefore acceptable as a good basis for a rational global policy, including the introduction of a broad-based system of emission trading[1], as long it is tied to Kyoto mechanisms. Statoil also cooperates widely with other companies and authorities, and is a significant player in global affairs through its memberships of the World Business Council for Sustainable Development, the Energy and Biodiversity Initiative (EBI), and bodies such as the IEA Greenhouse Gas R&D Programme and the IPIECA.

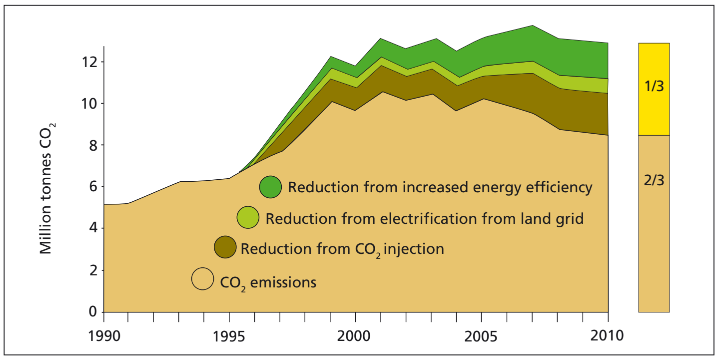
At home our specialists keep abreast of the latest developments in scientific knowledge about the greenhouse effect, and the social, economic and competitive impact of climate policies aimed at the

[1] Emission trading gives industrial countries the opportunity to meet obligatory reductions in emissions by purchasing quotas from other industrial nations or by cutting emissions for them.

Windmill park near Gøteborg, Sweden. (Photo: Asle Strøm.)

petroleum industry and the energy market. The chief executive officer also regularly meets environmental and consumer organizations to discuss issues ranging from the disposal of produced water[2] to reducing greenhouse gas[3] emissions, of which CO_2 is the most important.

The company's intention is to reduce CO_2 emissions from its operating facilities by about one third by 2010. Based on the findings of a comprehensive corporate programme (1997-2001), the primary measures are the injection of CO_2 into saline aquifers and reservoir rocks for long-term storage or to improve oil recovery; using hydroelectricity from the Norwegian grid to power installations presently employing on-site generation; and increasing energy efficiency.



Primary measures aimed at reducing CO_2 emissions by about one third from Statoil-operated facilities.

Research history in brief

One of our earliest engagements in CO_2 capture and storage was in the late 1980s when the Continental Shelf Institute[4] was commissioned to carry out a pilot study on environment-friendly gas power and CO_2 injection for improved oil recovery.

Similar research began at the Statoil Research Centre in 1989, but it was not until the early 1990s that internal activities really began to intensify.

In 1992 Statoil joined forces with Kværner Process Systems, NTNU and SINTEF to examine whether membrane technology for capturing CO_2 from power station emissions would lead to significant weight, space and cost reductions.

At about the same time, Statoil and partners decided that excessive amounts of CO_2 contained in natural gas from the offshore Sleipner field should be stripped off and injected into a saline aquifer situated above the hydrocarbon reservoirs. The primary goal was long-term storage to protect the natural environment.

To learn as much as possible from the Sleipner case, Statoil and the IEA Greenhouse Gas R&D Programme organization set up the European Commission's SACS[5] project (phases 1 and 2, 1998-2003), which led to the Sleipner experience becoming a truly multinational concern with global applications in mind. The present CO_2 Store project (2003-2005) is essentially a SACS extension, addressing long-term predictions of the aquifer's behaviour and the transfer of approaches and methods to onshore and nearshore industrial sites.

The aims of the complementary, BP-coordinated CO_2 Capture Project (2001 - 2003) were to reduce capture costs by more than 50 per cent at existing plants and by 75 per cent at new ones. Emphasis was placed on the development and qualification of technology for capturing CO_2 emitted by gas turbines and power stations. The project involved eight major oil and energy companies[6], and included three distinct regional programmes run in the United States, Norway and the European Union. Statoil headed the Norwegian 'Klimatek – NorCap' contribution. And in common with the SACS initiative, the participants wished to demonstrate that CO_2 storage is safe, measurable and verifiable.

Statoil is also looking at ways of transforming the CO_2 challenge into viable business opportunities. One area under investigation is the transport of CO_2 by ship and pipeline to mature offshore fields requiring gas-based improved oil recovery (IOR) programmes. The idea is to use CO_2 instead of hydrocarbon gas as an oil-miscible component to improve sweep efficiency.

Awards

In 2002 the group received two major awards: the World Petroleum Congress's technology development prize for its pioneering efforts in underground carbon dioxide storage; and a 2002 World Summit Business Award for Sustainable Development Partnerships, in association with EBI colleagues.

These awards testify that Statoil's long-term efforts in environmental stewardship are paying off both in terms of industrial application and global awareness.

Executive vice president Peter Mellbye receiving the 2002 World Petroleum Congress's technology development prize in Rio de Janeiro.

[2] Produced water is natural formation water contaminated during the hydrocarbon production process.

[3] Non-CO_2 greenhouse gases include methane, N_2O and engineering chemicals such as HFCs, PFCs and SF_6.

[4] IKU, now SINTEF Oil and Energy (Trondheim, Norway).

[5] SACS - Saline Aquifer CO_2 Storage. Collaborating organizations: industry - BP, Exxon Mobil, Norsk Hydro, Total and Vattenfall; institutes – BGS, BRGM, GEUS, IFP, NITG-TNO and SINTEF; assistants - NERC, GECO and the IEA greenhouse Gas R&D Programme; national bodies - ministries and research councils in Norway, Denmark, the Netherlands, the United Kingdom and France.

[6] BP, ChevronTexaco, EnCana, Eni, Norsk Hydro, Shell, Statoil and Suncor. Other participants were the Norwegian Research Council (NFR), the Department of the Environment (DoE) and the European Union.

THE OPTIONS

Long-term oceanic and underground storage promises to help nature cope with excessive carbon dioxide emissions to the air – the latter being the most realistic solution, at least in the near future.

Trees and other plants use up vast quantities of CO_2 by absorbing it as they grow and retaining it throughout their lifetimes: much is also taken up by seas and oceans. However, these natural mechanisms appear to be inadequate to constrain current levels of anthropogenic (man-made) emissions, especially with continuing denudation of the rain forests and the ravaging of fertile ground by sprawling urbanization. Clearly there is a pressing need for new measures to be introduced, such as the disposal of CO_2 in the ocean and long-term underground storage.

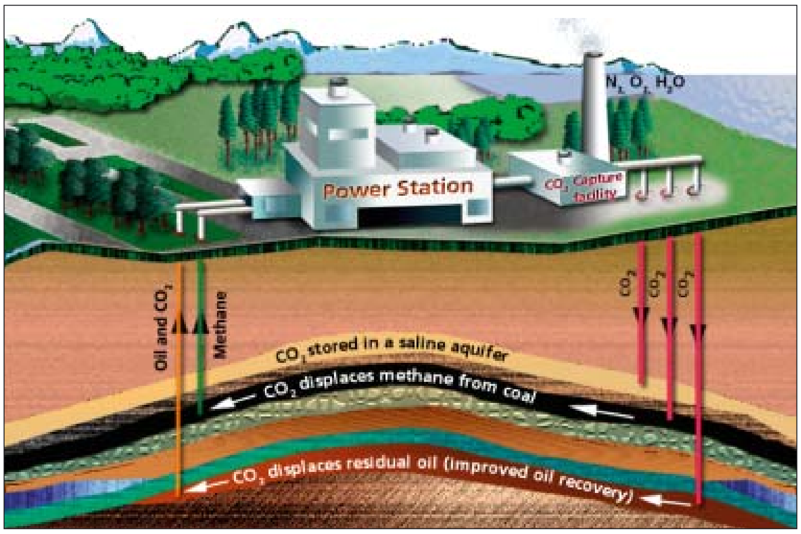
The oceanic storage concept involves the bubbling of gas directly into the sea at concentrations low enough to avoid damaging surrounding ecosystems, and at sufficient depths to ensure that it stays there. Various methods have been suggested, including droplet plumes emanating either from the outlets of deep pipelines linked to onshore CO_2 pumping stations or from pipes dangled from CO_2 transport ships. Other possibilities include the injection of CO_2 from offshore pumping stations into abyssal depths to accumulate as stagnant lakes, and the dropping of solid CO_2 into the sea in the form of dry ice.

Although oceanic storage offers the greatest storage capacity, there are major uncertainties about the environmental impact and retention times. Statoil is therefore no longer actively engaged in oceanic disposal storage research but closely follows the latest scientific developments.

Long-term underground (subsurface) storage is regarded as the more reliable solution, requiring CO_2 to be injected into deeply buried geological formations. The main candidates are depleted oil and gas reservoirs, deeply buried saline aquifers and unminable coal seams.

The attraction of using depleted oil and gas reservoirs is obvious: they are proven traps; the reservoir geology is well known; and infrastructures can be readily adapted for CO_2 transport and injection. Indeed, depleted hydrocarbon gas fields and saline aquifers have long been used on a commercial basis to inject, store and withdraw natural gas according to supply and demand. At present there are 595 underground storage sites worldwide, whose collective working gas storage capacity is equivalent to 11 per cent of the world's consumption.

There are also innumerable saline aquifers around the world that could be used for long-term CO_2 storage. In both cases – depleted reservoirs and saline aquifers – much of the injected gas will eventually dissolve in the formation water, while some may react with the minerals to form carbonate precipitates.



Cartoon showing various subsurface options for CO_2 storage and utilization. (A CCP illustration modified by Johnny Schumann.)

An important storage issue is sealing capacity; that is, the ability of the overlying (cap) rocks to stop the CO_2 from leaking out and rising back to the surface. To fulfil this criterion, cap rocks should be almost impermeable, and ductile rather than brittle if natural and induced fractures are to be avoided. Onshore leakage can affect water supplies and devastate vegetation cover.

For coal seams, the theory is that injected CO_2 will be permanently locked in the coal by adsorption while enhancing methane production by preferential displacement.

Rough IEA estimates of how much CO_2 could be stored in these various geological options are >15 Gt* in unminable coal seams, 920 Gt in depleted oil and gas fields, and 400-10 000 Gt in deep saline aquifers. With the atmosphere today containing about 730 Gt of CO_2, saline aquifers obviously hold considerable promise.

Onshore CO_2-based improved oil recovery is an established practice, which is yet to be tried offshore (see p. 16).

*One gigatonne or Gt is a thousand million tonnes.

THE SLEIPNER WEST GAS FIELD

The Sleipner asset notched up two world firsts in pursuit of environmental protection – large-scale offshore carbon dioxide separation and injection into a saline aquifer 1 000 metres below the seabed.

The Statoil-operated Sleipner West[1] field is one of the largest gas producers in the Norwegian sector of the North Sea, with a daily gas export capacity of 20.7 million cubic metres and a daily output of 60 000 barrels of stabilized condensate (light oil). It was discovered in 1974 close to the British/Norwegian sector divide and is linked to Sleipner East. Both fields are produced by a single operations organization.

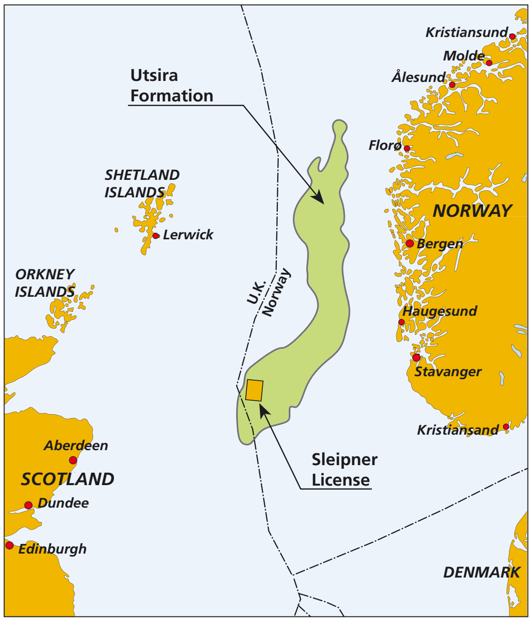
During field development planning (1990), it was realized that the 4 to 9.5 per cent CO_2 content in the natural gas would have to be reduced to less than 2.5 per cent if it were to be fed directly into sales gas pipelines to Europe. A small team of technical experts came up with the unprecedented idea of capturing the CO_2 offshore and injecting it into a saline aquifer beneath the Sleipner installations. In this way, the Sleipner asset would minimize CO_2 emissions – the prime motive – while avoiding environmental taxes[2]. Despite its pioneering nature, this became the partner-approved solution.

Of various possibilities, the Elf-patented separation process was selected for CO_2 capture, because it was deemed cheaper to run and more compact than competing systems. One of the greatest challenges, however, was to scale down the process plant sufficiently so that it could be accommodated on a platform. Even so, the 'miniaturized' version of the extraction module weighed 8 200 tonnes – the heaviest module ever to be lifted offshore – and measured 50 m x 20 m x 35 m.

[1] The present partners are ExxonMobil, Norsk Hydro and Total.

[2] At this time the Norwegian government was discussing climate change and the possibility of introducing a national carbon tax. The latter became law in 1991 and currently stands at USD 40 per tonne.

The Sleipner T gas treatment installation (left) linked by a bridge to the Sleipner A platform. (Photo: Øyvind Hagen.)



Location map showng the Sleipner licence and areal extent of the Utsira Formation.

By the time the field came on stream in 1996, the Sleipner organization had notched up two world firsts: the installation of a large-scale offshore CO_2 extraction plant at the Sleipner T (Treatment) platform; and the facilities for saline aquifer injection from the Sleipner East A platform.

Carbon dixide capture and injection

The carbon dioxide content in the natural gas can now be kept below 2.5 per cent by increasing the amine circulation rate and total heat input

Carbon dioxide capture process

The first stage in the Sleipner CO_2 capture process entails the mixing of an amine-water solution with the natural gas in two parallel columns (absorbers A and B), both of which are kept at high pressure (100 bara[3]) and moderate temperature (60 - 70 °C). The amine – an organic compound derived from ammonia – selectively absorbs the CO_2 by weak chemical bonding and separates out at the bottom of the columns. Thereafter it is transferred via a turbine to a 15 bara

[3] Bara – bar absolute (not to be confused with barg – bar gauge).

flash drum in which the co-absorbed hydrocarbons are removed. The amine is subsequently heated and de-pressurized to 1.2 bara in a second flash drum where the CO_2 is boiled off. By now the gas is almost (95%) pure CO_2.

As the lean liquid amine still contains residual CO_2, some 10 per cent is subject to thermal regeneration where the CO_2 is stripped off by steam in a desorber column operating at 120 °C. The remaining, even leaner amine is then mixed with the regenerated amine and pumped back to the absorbers for a new separation cycle.

Experimental investigations

In practice it has been difficult to keep consistently within the 2.5 per cent goal because the process has proved somewhat unstable. This led to several modifications, including new internals for the gas scrubber to reduce carry-over (1997-1998), a comprehensive rebuilding of absorber A (1999) and new internals for absorber B (2000). However, faced with continuing irregularities, the Sleipner Amine Task Force asked Statoil researchers to devise a solution.

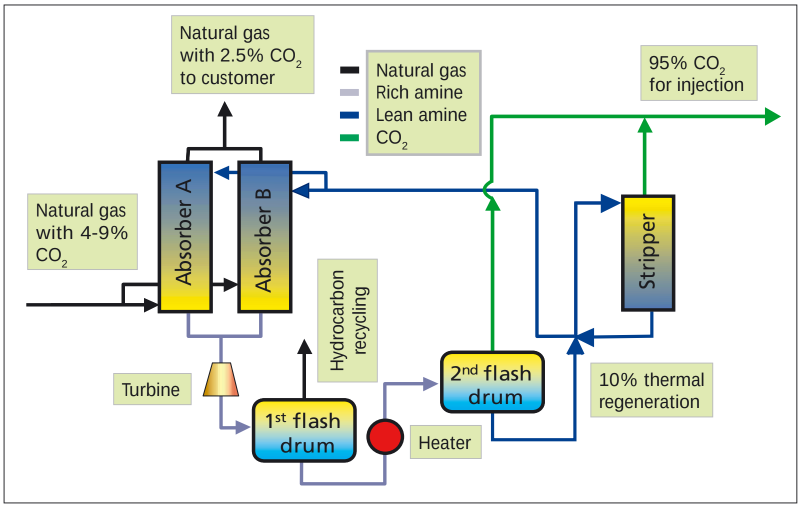
By now we had acquired much knowledge about the removal of CO_2 at high pressure while attempting to improve the plant's performance. Indeed, one of Statoil's most important experimental observations was that pressure has a significant effect on the absorption capacity of the amines – adsorption capacity decreases with increasing pressure. Naturally this was a cause for concern as it could impact the effectiveness of CO_2 capture in the absorber columns.

Spurred on by the task force's request, Statoil stepped up its engagement through a major experimental and modelling investigation aimed at better understanding and predicting high pressure CO_2 capture mechanisms. This involved experimenting with genuine natural gas under realistic pressures and temperatures. The effects of various amine solution additives were also tested under similar conditions.

However, it was not until 2003 that a major breakthrough was made. Exploiting the Research Centre's unique laboratory facilities, the answer was found to lie in increasing the amine circulation rate and the heating energy used to separate CO_2 from the amine. Subsequent offshore tests at Sleipner resulted in a stable performance while reducing the CO_2 content to 2.25 per cent. The new operational procedure and equipment can now be installed at Sleipner T, enabling the amine plant to meet quality specifications when operating at full capacity.

Aquifer injection

Once the CO_2 has been captured, its pressure is boosted by four compressors to 80 bara prior to being transferred to the Sleipner East A platform for



Process flow chart illustrating CO_2 capture at the Sleipner T platform. (Illustration: Gelein de Koeijer.)

pumping into the base of the saline aquifer. Since 1996 about 1 million tonnes of compressed CO_2 have been injected annually.

Another requirement is that the well casing and other hardware used in the capture and injection plant have to be made of stainless steel, because even minute quantities of water mixed with CO_2 produce a weak corrosive carbonic acid (H_2CO_3).

Investment costs amounted to some USD 80 million (CO_2 capture costs excluded). Although this was a considerable sum, the partners would otherwise have faced an annual tax bill of about USD 50 million if the CO_2 had simply been vented into the air.

Geological aquifer and cap rock characterization

The storage capacity of the saline Utsira aquifer is thought to be greater than 100 times the volume of annual European carbon dioxide emissions from power plants

The aquifer in question is the Utsira Formation, which the SACS team believes was deposited as part of a submarine turbidite fan system[4] above the Sleipner reservoir rocks. Today it is encountered some 1 000 metres below the seabed[5], and comprises an exceptionally porous and permeable sequence of poorly consolidated, fine- to medium-grained quartz rich sandstones. Sub-cropping almost exclusively in the Norwegian sector of the North Sea, it is more than 200 metres thick, over 50 kilometres wide, and extends for some 500 kilometres in a sinuous strip beneath the Brage, Oseberg, Grane and Sleipner fields and the Tampen production centre to the north. The

[4] 'Turbidites' is a relatively loose term for sediments carried from shallow to deep water by gravity-induced flows and deposited at the base of slopes. Here they may form fan-like or lobate bodies, fringed by thin-bedded sand/mud couplets.

[5] The Utsira Formation sandstones have porosities between 24 and 40% and permeabilities between 1and 3 Darcy.

aquifer's areal coverage is thus about 26 000 square kilometres.

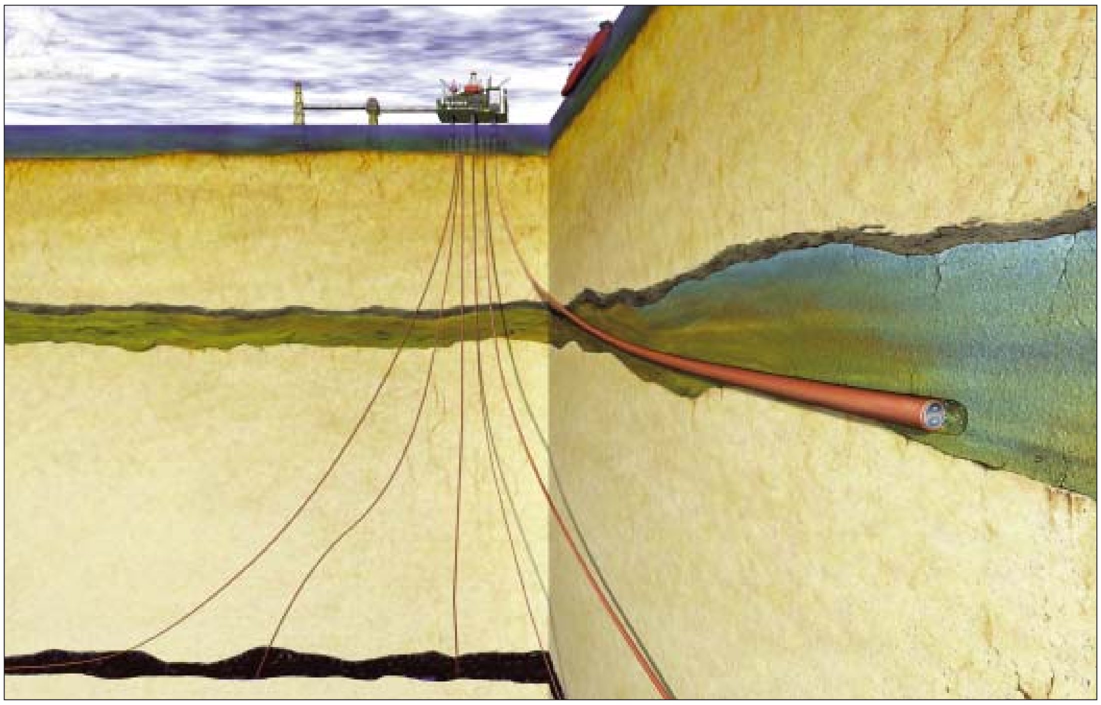
Delineation and mapping of the top of the formation is particularly important for defining its closure. If aquifers form large domal structures, the CO_2 will be constrained and slight structural uncertainties can be ignored. However, precise and detailed depth mapping is vital if they undulate gently, as at Sleipner where the top of the aquifer above the injection point is relatively flat. This is because minor variations may have a major effect on CO_2 movement (migration routes), areas of accumulation and overall storage potential.

The regional mapping was done using 2D seismic datasets, while more detailed work was carried out around the injection point using 3D seismic[6]. Petrophysical data from some 300 wells were also available for study, plus limited rock samples in the form of drill cuttings and cores. Much sedimentological, geochemical and rock-mechanical research is still being done on the complex cap rock/overburden sequence, which at Sleipner is about 700 metres thick. A dedicated 9-metre core was cut from this interval in the summer of 2002.

[6] In 3D surveys, seismic lines are shot so close together that the data can be represented as seismic data 'cubes'. In 2D surveys, seismic lines are often several kilometres apart, requiring geoscientists to interpret what goes on in between them.

Another consideration is the possible presence and continuity of faults running through the aquifer and cap rock along which CO_2 may escape to the seabed. Fortunately, no significant faults have been detected from the seismic surveys (also see below) .The injection process itself could lead to local microseismicity and/or the opening of incipient, pressure-induced fractures, but the required injection pressures at Sleipner are sufficiently low for this to be regarded as unlikely.

Furthermore, current thinking suggests that the plasticity of the overburden is such that faults and fractures are unlikely to serve as escape conduits. In other words the sealing capacity appears to be good.



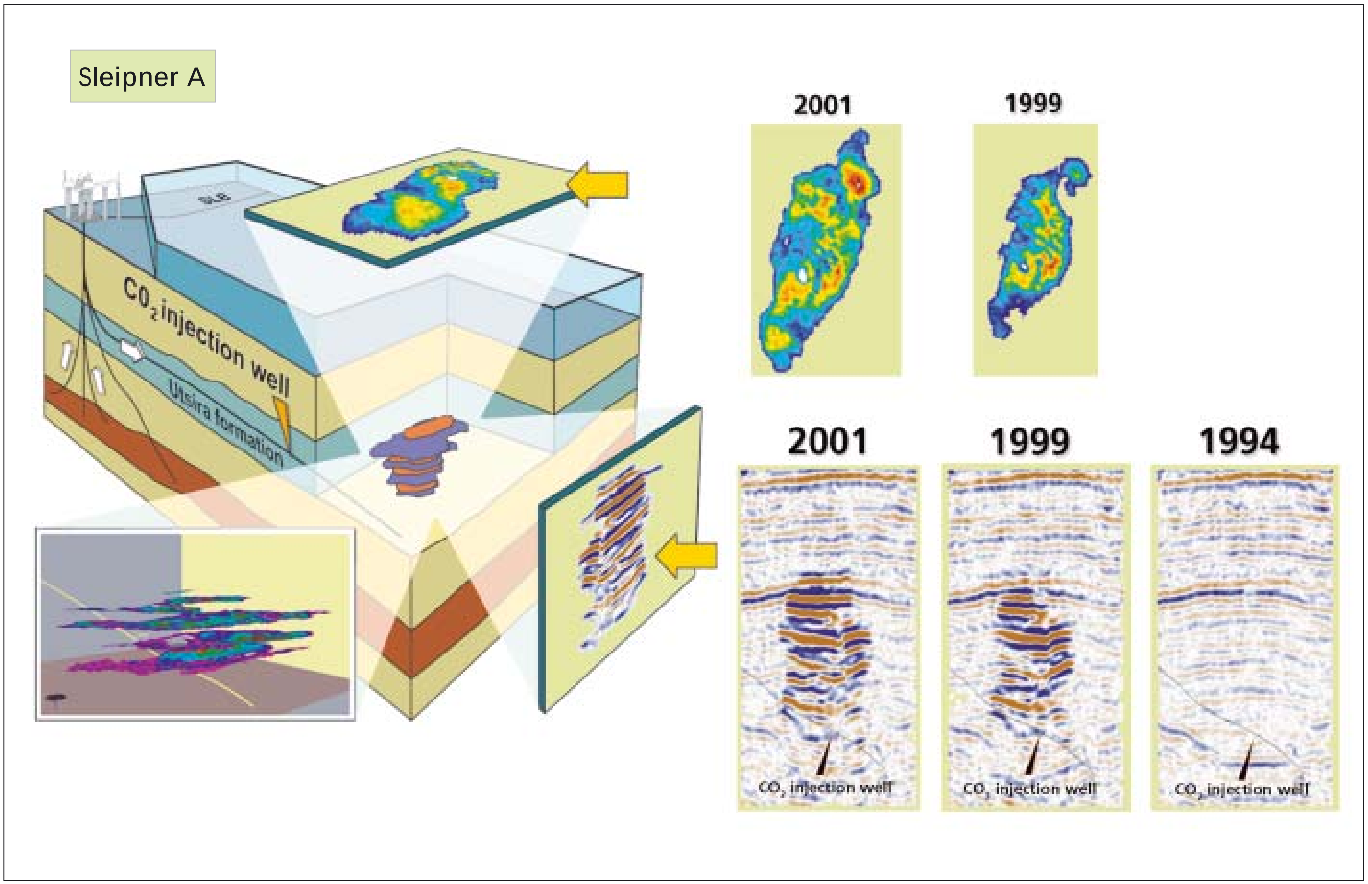
Injection of CO_2 into the Utsira Formation from the Sleipner A platform. (Illustration: David Fierstein.)

Seismic monitoring

Seismic monitoring has revealed no carbon dioxide leakage in the overburden

Another taxing question was whether the dynamic behaviour of the injected CO_2 and its potential impact on cap rock integrity could be monitored using modern geophysical techniques, especially seismic. After much discussion, it was agreed that time-lapse seismic would probably be suitable, because the velocity of sound waves should be able to differentiate between salt water-bearing (higher velocity) and CO_2-bearing (lower velocity) sandstones. Time-lapse seismic, which is also known as 4D seismic, involves comparing the results of 3D seismic surveys repeated at considerable time intervals: differences between the survey results are attributed to fluid and/or pressure changes.

Four seismic surveys have been conducted so far: a pre-SACS baseline survey in 1994 prior to CO_2 injection and three monitoring surveys carried out in 1999, 2001 and 2002 during CO_2 injection. The latter have not only successfully traced the injection of the CO_2 and expansion of the 'bubble', but have also yielded extremely sharp images of the aquifer's overall geometry, internal structure and flow behaviour. As expected, gravitational separation is the dominant physical process because of the CO_2's buoyancy.



Results of seismic monitoring. The 1999 to 2001 time-lapse seismic sections (lower right) show that the injected CO_2 is in place and that the volume has increased substantially – a fact which is further corroborated by the corresponding seismic amplitude maps (upper right). SLB - pipeline conveying CO_2 rich gas from the Sleipner B platform (Sleipner West). (Illustration: Erik Hårberg.)

A particularly striking result is that the distribution and migration paths of the CO_2 are strongly controlled by intra-aquifer mud rock horizons. With an extraordinary seismic detection limit of about 1 metre or less, much of the CO_2 can be seen to have migrated upwards between the Utsira Formation mud rock terminations, as witnessed by a distinct seismic chimney-like column appearing on repeated seismic surveys. What is more, it has travelled up to about 1 450 metres laterally beneath individual mud rock layers after six years of injection. The lateral speeds at which the CO_2 fronts move range from 0 to about 100 metres per annum – at least in recent years.

This remarkable precision prompted the team to estimate seismically the quantity of injected CO_2 – on the assumption (among others) that none has been dissolved in the saline formation water. By comparing the seismically based result with the injected volumes, it appears that all of the CO_2 is accounted for by the seismic data. This, of course, is another argument for suggesting that no significant leakage has occurred, although the lack of seismically observed CO_2 in the overburden remains the most persuasive factor. It is wise, however, to recall that there is always a margin of error associated with the seismic method – albeit relatively minor in this case.

Gravimetric aquifer monitoring

Time-lapse gravity can potentially be used to better determine carbon dioxide density and mass distribution

Although gravimetry has a lower spatial resolution than its seismic counterpart, repeated high precision microgravity monitoring potentially provides better constraints on CO_2 density and mass distribution. It may also give an early warning signal if considerable amounts are escaping upwards through the overburden, as well as yielding relatively inexpensive information on the long-term dissolution of the CO_2 in the formation water once injection has ceased.

Statoil's latest offshore time-lapse gravity surveying technique is being used, having been successfully employed at the Troll field to image and monitor changes in the (hydrocarbon) gas-water contact. Developed in association with Scripps (University of California, San Diego) and co-funded by the US Department of Energy, the state-of-the-art seafloor

Principle of seafloor gravity surveying. The Remotely Operated Vehicle - ROVDOG II - lowers the gravimeter onto concrete blocks placed on the seafloor (Illustration: Erik Hårberg and Johnny Schumann.)

gravimeter contains three gravity sensors and three pressure sensors, which enable the instrument to monitor small vertical changes in the seafloor as well as small gravity changes. The gravitational accuracy is about 5×10^{-9} of the earth's total gravity field.

A seven by three kilometre baseline survey was obtained at Sleipner in August 2002, against which future surveys will be compared. So far the results have exceeded expectations: not only may it be possible to detect vertical changes in the seafloor as small as 0.5 centimetres, but the time-lapse detection threshold may also be as low as 5 µGal[7] – some 50 per cent better than that suggested by a pre-survey modelling exercise.

[7] Gal – a unit of gravitational acceleration equal to one centimetre per second per second.

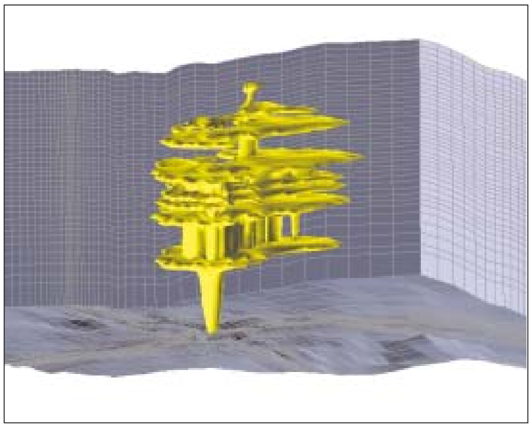
However, there are other considerations to be taken into account, such as the gravitational effect of further production from the underlying Sleipner gas-condensate reservoirs. The technique also depends on lowering the gravimeter onto separate concrete blocks installed on the seafloor one at a time, although this did not prove to be a hindrance.

Aquifer flow modelling

Simulations suggest that the carbon dioxide 'mega-bubble' may reach its ultimate size after a few hundred years, thereafter shrinking and finally disappearing within a few thousand years

Whereas geophysical surveys are designed to determine rock and fluid distributions, reservoir simulations are designed to predict how fluids will behave with time. In a case like this, it is naturally wise to make a pre-injection simulation to test operational feasibility, as was done at Sleipner before the SACS project started.

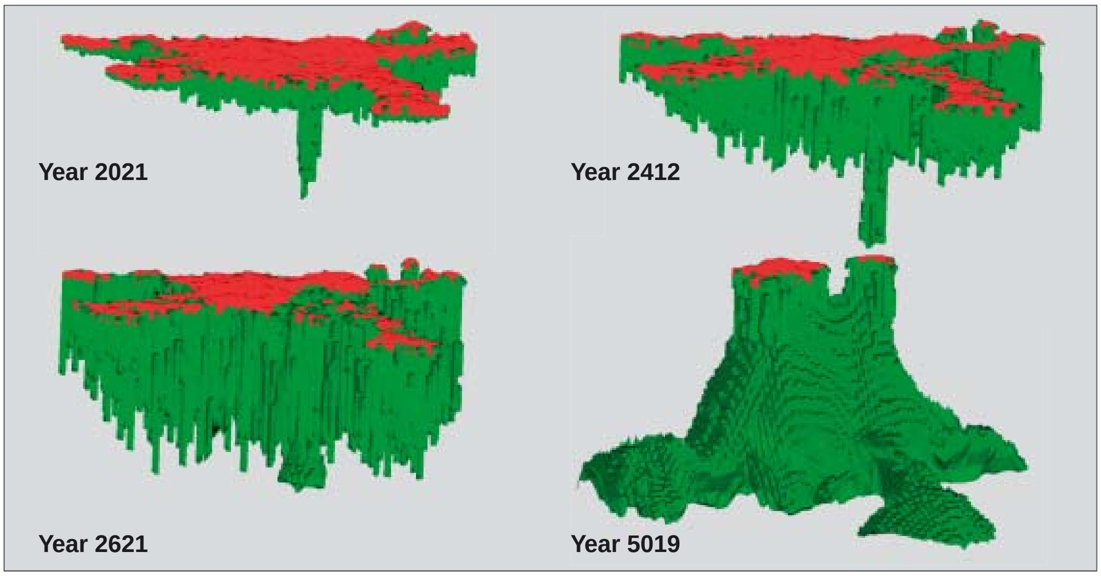
The SACS team has subsequently built a detailed post-injection model to verify and improve the seismic and geological interpretation of the aquifer around the injection site; and a coarser, larger-scale model to predict CO_2 migration over a period of several thousand years. The areas covered by the models are 7 square kilometres and 128 square kilometres, respectively. In both cases, the seismically inferred mud rock distributions were imported into the reservoir models, because it is almost impossible to trace individual mudstone layers from well to well, even when they are close together. Calibration of the 3D repeated seismic data with a local reservoir model is thus a fundamental prerequisite.



Reservoir model of CO_2 distribution after three years. (Source: SACS Best Practice Manual, 2003.)

The results from the larger model suggest that most of the CO_2 will eventually coalesce to form a single 'mega-bubble' beneath the cap rock a few years after injection has ceased. It will also gradually spread along the top of the salty formation water according to the local topography of the cap rock seal. This, however, must be tempered by the fact that CO_2 will diffuse from the 'mega-bubble' into the underlying brine column, a phenomenon that is usually ignored in standard reservoir simulations because it is extremely slow compared with other transport processes. But given time, the CO_2-enriched brine on top of the column will become denser than that beneath, resulting in a downward flow compensated by convection plumes. This, in turn, will enhance dissolution and increase the probability of the CO_2 remaining in the aquifer.

When dissolution is included in the simulations, the 'mega-bubble' will probably reach its ultimate size after a few hundred years, thereafter shrinking and finally disappearing within a few thousand years.



Simulated dissolution of CO_2 in the saline water (brine) of the Utsira Formation. Red = supercritical CO_2; green = CO_2 rich brine. (Courtesy Erik Lindberg: a modified illustration from that originally published in the SINTEF - NTNU Gemini magazine.)

Further investigations

The ultimate objective is to combine chemical and flow-oriented modelling approaches for making reliable, long-term predictions

The main product of the SACS project is a comprehensive Best Practice Manual (2003). This contains a suggested procedure for evaluating CO_2 storage from a technical point of view, besides information aimed at satisfying authorities and the general public as to the feasibility, safety and reliability of the storage process.

The Sleipner case, which is being used as a full-scale natural laboratory, has yielded copious information on CO_2 transport rates and geophysical properties, and has gone some way towards assessing the sealing capacity of the overburden.

These are considerable shorter-term achievements, of which the seismic monitoring is the most conspicuous. However, some of the most telling challenges still lie ahead, particularly the making of reliable long-term predictions, recalling that 'long-term' in this context refers to several hundred to several thousand years hence.

Ongoing investigations in the CO_2 Store programme (2003-2005) include assessments of whether the free and dissolved CO_2 remain in the host aquifer or migrate elsewhere; and whether the sealing capacity of the cap rock will be maintained, realizing that CO_2-rich water is slightly acidic and may lead to mineral dissolution.

Other important issues are whether and how much of the injected CO_2 can be permanently fixed by chemical reactions and in what forms; and whether such chemical changes will impair porosity and permeability, thereby reducing aquifer storage capacity while (possibly) improving retention. The conditions under which CO_2 might ultimately be dissolved in its entirety are also receiving attention.

In short, the CO_2 Store programme aims to extend the capabilities of two-phase (gas, water) reservoir simulators to better handle extremely long-term simulations, including the migration of CO_2 in its dissolved form; and chemical-oriented modelling to predict the maximum potential for CO_2 reaction with the Utsira Formation sediments and the cap rock.

The ultimate objective is to combine chemical modelling with the flow-oriented modelling approach of reservoir simulation to produce merged 'chemical and reactive transport models' constrained by geological and geochemical understanding – a highly ambitious undertaking. Geo-mechanical modelling is also coming to the fore in a number of related investigations.

THE SNØHVIT AND IN SALAH PROJECTS

With the addition of Snøhvit and the In Salah gas projects, Statoil is now involved in the world's first three carbon dioxide storage projects solely aimed at protecting the natural environment.

The Snøhvit development in the Barents Sea

Statoil and partners are planning the second largest offshore carbon dioxide storage project at Snøhvit based on the Sleipner West experience

Moving on from Sleipner West, Statoil and partners[1] are planning the world's second largest offshore CO_2 storage project for the Snøhvit unit in the central part of the Hammerfest basin in the Barents Sea. The production area extends across seven unitized licences, covering the Snøhvit field itself and the Albatross and Askeladd satellites. All three accumulations contain natural gas and small quantities of condensate. The Snøhvit unit is scheduled to come on stream in 2006, some 25 years after the first gas discovery was made at Askeladd in 1981.

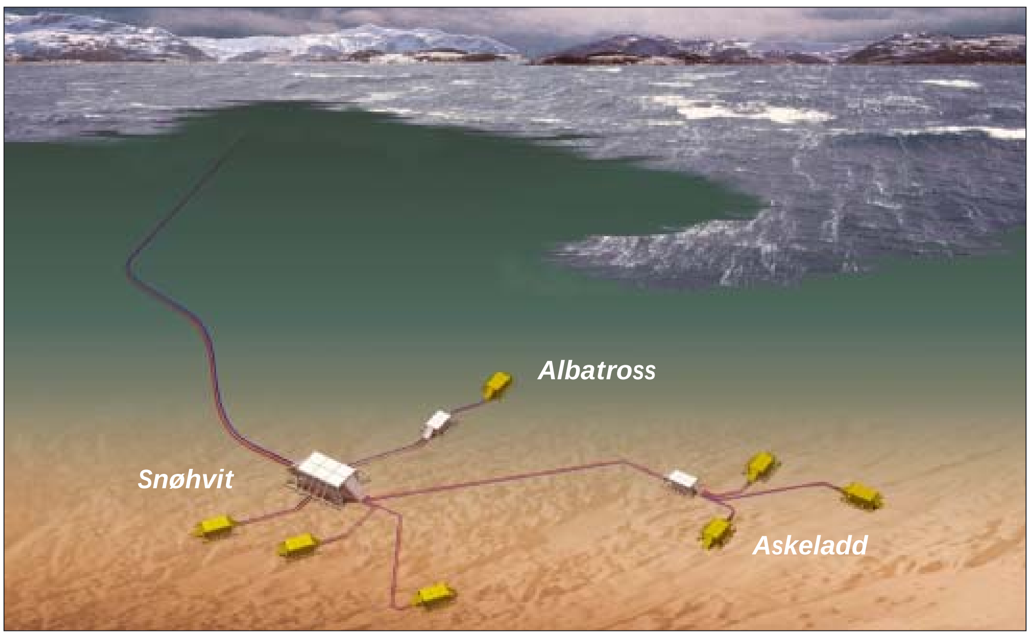
[1] Petoro, Total, Gaz de France, Amerada Hess and RWE-DEA.

The unitized complex will be developed entirely using subsea production installations, linked by a record-breaking 143-kilometre multiphase flow pipeline to a processing and cryogenic gas liquefaction plant located at Melkøya – a small island outside Hammerfest.

The main product, LNG (liquefied natural gas), will be shipped to the USA and continental Europe in four purpose-built vessels, each 290 metres long and capable of carrying about 140 000 cubic metres of LNG in spherical tanks. Condensate and liquefied petroleum gas (LPG) will also be produced in relatively minor quantities. The LNG plant's production capacity will be about 5.7 billion cubic metres of gas per year.

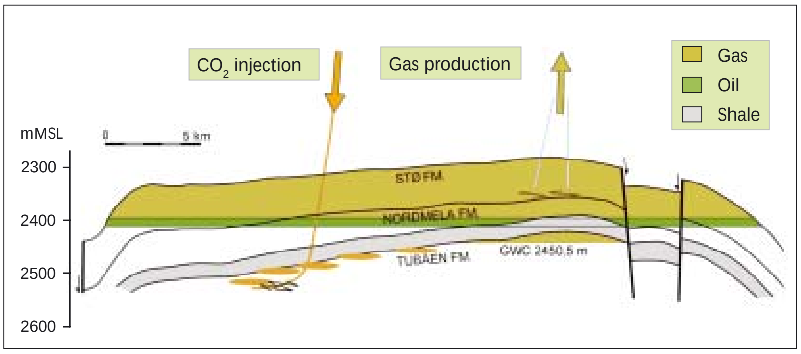
The Snøhvit LNG project is the first oil and gas development in the environmentally sensitive Barents Sea and the first LNG-based gas field development in Europe. Furthermore, it is the first Norwegian offshore development with no surface installations. With all of the production equipment residing in water depths of 250 to 345 metres, none will interfere with fishing activities. Operations will be remotely controlled from land.

The gas in all three accumulations contains 5 to 8 per cent CO_2, which will have to be reduced to less than 50 parts per million prior to liquefaction. This means that about 700 000 tonnes of CO_2 will have to be captured each year. Having reviewed several disposal options, it was decided that the CO_2 will be injected into the Tubåen Formation – a deeply buried saline sandstone aquifer encountered at the Snøhvit field about 2 600 metres below the seafloor and about 60 metres beneath the main natural gas reservoir in the Stø Formation.



Artwork of the multiphase pipeline linking Snøhvit and satellites to the LNG plant at Melkøya, northern Norway. (Illustration: Even Edland.)

The Tubåen Formation contains some shale intervals that are difficult to correlate from well to well. Good interconnection between the sand bodies is thus anticipated. And with a thickness of about 47 to 75 metres, a net-to-gross ratio[2] of 0.8 to 0.9, and good reservoir properties[3], the formation should be able to cope easily with the estimated storage requirement of about 23 million tons of CO_2 during the 30-year lifetime of the Snøhvit project. The formation is sealed by shaley caprocks of the intervening Nordmela Formation, which should be sufficient to stop the injected CO_2 from rising to contaminate the natural gas reservoirs above.



Geological cross-section showing the path of the Snøhvit CO_2 injection well.

The separation process will again be amine-based and cost about USD 100 million. The main difference between the Sleipner T and the Snøhvit plants is that the latter will be capable of stripping residual CO_2 from all of the lean amine solution after initial separation. And it goes without saying that Statoil's world-class expertise gained at Sleipner is being fully exploited during the planning phase.

[2] Ratio of total (net) sandstone thickness or volume to total (gross) thickness or volume.

[3] Porosity 10 to 16 per cent; permeability 130 to 890 mD.

The In Salah Gas project, central Algeria[4]

[4] Most of this section is based on BP and Sonatrach material in the public domain.

Plans are underway to reduce greenhouse gas emissions from the jointly operated In Salah Gas project by about 60 per cent

The third CO_2 injection project concerns the jointly operated Sonatrach[5]-BP-Statoil In Salah dry gas project – the third largest of its kind in Algeria. The agreement covers the development of eight hydrocarbon gas discoveries in the Ahnet-Timimoum Basin in the central Saharan region of the country, and proposes to deliver 9 billion cubic metres per annum.

[5] Sonatrach is the Algerian State Oil and Gas Company.

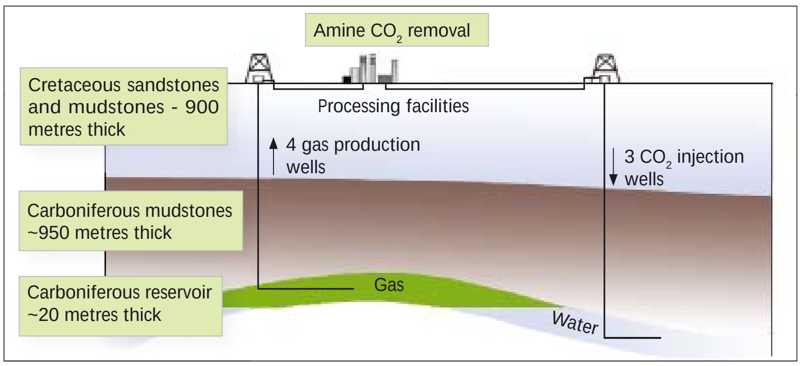
Some of the gas streams will contain CO_2 concentrations as high as 10 per cent, whereas export sales gas specifications require a CO_2 concentration of less than 0.3 per cent. To achieve this target, it has been estimated that some 1.2 million tonnes of CO_2 will probably have to be stripped off and stored each year from mid-2004 when the gas comes on stream.

Prior to Statoil's entry in 2003, BP and Sonatrach began searching for suitable subsurface sites close to the planned In Salah processing facilities that would be blessed with large storage potentials, reasonably good reservoir properties and good sealing capacities. Several possibilities emerged, ranging from storage sites at each field to a single centralized facility. Of these various options, the latter solution was favoured because of the high cost and complexity associated with distributed subsurface storage.

BP and Sonatrach thereafter identified the Krechba field as the most appropriate candidate. Here the CO_2 will be pumped through two or three horizontal wells directly into the aquifer section (below the gas-oil contact) around the northern periphery of the shallow Krechba sandstone reservoir. The reservoir rocks are of Carboniferous age and were deposited by a tidally influenced estuary infilling an incised valley system. Reservoir thicknesses vary from 5 to 24 metres within a broad, largely un-faulted, anticlinal fold. It is thought that the injected CO_2 will only migrate upwards into the producing structure of the main field once the field has been fully depleted and abandoned.

From a rigorous evaluation using reservoir simulation models, BP estimated that breakthrough of the injected CO_2 into central gas wells is unlikely to occur within the first 15 years of production. By then, reductions in CO_2 production from the other In Salah fields will have freed CO_2 handling capacity at the Krechba surface facilities. The model, which will be up-dated, has also been used to identify well locations that satisfy criteria such as accessing connected sandstone volumes to accommodate the predicted quantities of CO_2 and minimizing flow line distances.

The separation plant will again be amine-based.



Sketch of CO_2 storage at the Krechba field, Algeria, showing that the CO_2 will be injected into the water leg beneath the gas-water contact.

POWER PLANTS

Past and present research is bringing the possibility of cost-effective carbon dioxide capture and storage from power plants ever closer.

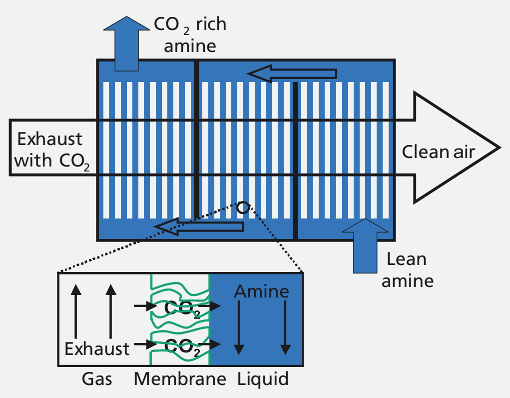
Kårstø and Osaka pilot plants

Membrane technology promises to reduce weight and space at CO_2 separation plants, as well as costs

Besides CO_2 capture and storage from gas fields, Statoil has done much research on the cleaning of flue gas emissions from coal- and gas-fired power plants. Although the power industry is the greatest contributor to global CO_2 emissions, CO_2 capture remains an elusive goal because of the low concentrations of CO_2 contained in exhaust fumes and the cost of removing them.

Statoil's initial work was largely centred on a flagship venture, which started in 1992 as a joint industry project with Kværner Process Systems, NTNU and SINTEF. The main aim was to investigate whether membrane contactors could replace the bulky amine towers currently used for CO_2 absorption and desorption. Ongoing studies are concerned with verifying the current technology and making further improvements.

The membrane concept is simple: a gas absorption membrane serves as a contact device between a CO_2-rich flue gas flow on one side and the flow of an absorption fluid on the other. Separation occurs as the CO_2 is selectively drawn through the membrane by the attraction of the absorption fluid. The CO_2 is then removed from the liquid at elevated temperature and pressure by essentially reversing the procedure so that the membrane acts as a desorption device. The membranes are generally made from porous, hydrophobic materials, although their exact constructions are far more complex.



Membrane separation principle. (Illustration: Kværner, MHI, Kansai.)

W L Gore and Associates (Gmbh) supplied designer membranes for installation at two major pilot plants – one in Norway (at Kårstø) and one in Japan (Osaka). The Japanese leg was in cooperation with the Kansai Electric Power Company, Mitsubishi Heavy Industries and the Carbon Dioxide Capture Project (see below). The main difference between the two investigations is that a conventional amine was used at Kårstø, while a recently developed alternative was tested at Osaka.

The main advantage of membrane technology is that it reduces weight and space by about 50 per cent, thus making it especially suitable for offshore CO_2 as well as onshore capture. What is more, degradation of the absorbent can be reduced, and entrainment and foaming are totally avoided.

The results from both pilot plant tests are very encouraging, not only because of the weight/space advantages but also because of potential cost reductions.

Carbon dioxide capture project

The recent carbon dioxide capture project placed the challenge of reducing carbon dioxide emissions on the international agenda

While this work was underway, Statoil decided to widen its technological net by participating in several broad-based international studies, the latest and most comprehensive being the Carbon Dioxide Capture Project (CCP).

As stated in the Introduction (p. 4), the main aim of the project (2001-2003*) was to reduce the costs of CO_2 separation and capture by more than 50 per cent for existing plants and by 75 per cent for new ones. Other objectives included ways of demonstrating to authorities and the public that CO_2 storage is safe, measurable and verifiable, and to advance technologies towards a 'proof of concept' stage.

* Although the project is officially over, several results are still being received.

Test plant at Kårstø for removing CO_2 from flue gas. (Courtesy: AkerKvaerner.)

With such an immense scope, it is hardly surprising that most of the conclusions point to further research. Even so, there are many significant results. For CO_2 capture, the consortium developed a broad portfolio of technologies that will serve as the basis for the next generation, and has shown that all three of the main technical areas – pre-combustion, post-combustion and oxyfuel – have considerable potential for reducing costs. Furthermore, a new set of tools has been developed for managing long-term CO_2 storage, as well as a unique risk-based approach covering both aspects.

However, it was concluded that CO_2 capture and storage from heat and power production is still too expensive in the light of current oil and gas prices and taxes. Moreover, no technology is emerging as a clear leader, although several promising areas may be on the brink of commercialization.

Perhaps the project's most resounding achievement was that industries and governments came together in an international forum to promote strong technical leadership.

The CO_2 Store project

Statoil and European partners are studying the possibility of extending Sleipner expertise to onshore industrial sites

Another investigation is currently assessing whether the Sleipner experience can be extended to onshore industrial sites. This is being done as part of the aforementioned CO_2 Store project, in which four European locations have been earmarked for extensive feasibility studies:

1. *Denmark:* the Energi E2-operated power plant and Statoil's Kalundborg refinery, which constitute the largest, single Danish CO_2 emission point source accounting for some 6 million tonnes of CO_2 per year. The power plant fuel is coal and orimulsion – a fuel consisting of a bitumen-in-water emulsion.

2. *South Wales (UK)*: a prospective gasification/combined cycle power station to be developed by Progressive Energy using a mixture of anthracitic coal and green petcoke. The proposed technical solution involves pre-combustion CO_2 capture, possibly amounting to 1-2 million tonnes per year.

3. *Part of the Trøndelag Platform*: an area off the Norwegian coast that contains several CO_2 point sources and where others are being planned.

4. *Germany*: the Schwarze Pumpe power plant operated by Vattenfall's subsidiary VEAG (Vereinigte Energiewerke AG). The plant is fuelled with lignite and each block emits about 5 million tonnes of CO_2 per year.

Both onshore and nearshore repositories will be investigated, including those with large structural closures, depleted fields and regional deep saline aquifers.

The intention is that research will progress to such a stage that industry and national authorities can make an informed decision as to whether injection is a practical proposition in their respective areas. This, however, is not as straightforward as it seems, because judicial, safety and geological considerations will differ significantly from place to place. The Sleipner experience will therefore have to be adapted to meet local conditions.

By the time this part of the CO_2 Store project has run its course, the participants hope to offer a tool kit of various technologies and procedures that can be matched to suit the requirements of any deep saline aquifer, wherever it may be. The SACS 2003 Best Practice Manual will be updated accordingly.

Other projects

Although space limitations preclude extensive coverage of all but the most eye-catching projects, it is important to mention that other collaborative ventures and proprietary in-house projects are systematically examining the entire range of available technologies. Among them, Statoil is a partner in three, integrated, multi-partner ventures which are partly funded by the European Union; namely, ENCAP, CASTOR and CO_2Sink. These are concerned with pre-combustion, post-combustion and storage, respectively.

We are also jointly involved in several basic research projects, two of them dealing with CO_2 capture and one with the use of CO_2 for improved oil recovery (see p. 16). The aims are to elucidate fundamental physico-chemical phenomena in the hope of making significant breakthroughs.

CARBON DIOXIDE UTILIZATION

Assessing the viability of carbon dioxide-based miscible gas injection for improving oil recovery from offshore fields.

Of course it would be far better if the unwanted by-product could be converted into a green and profitable commodity.

Unfortunately, the world's consumption of brewed and carbonated drinks falls well short of using up the vast quantities of excessive anthropogenic CO_2, and the European market for so-called food grade CO_2 is currently running at only 2.7 million tonnes per year.

Other enticing possibilities are self-defeating in the sense that they normally involve the use of energy, thereby producing even more CO_2.

One way of overcoming this is to use CO_2 as a means of improving oil recovery (IOR). When the conditions are right, the injection of CO_2 into a petroleum reservoir results in partial storage while improving the cash flow.

At the last count, some 70 or more onshore fields in the USA use CO_2-based miscible[1] gas injection to squeeze more oil out of the reservoirs. Here there are several natural sources[2] of high grade, high pressure CO_2, as well as a pipeline infrastructure linked to the fields in question.

A comprehensive study[3] of 115 onshore fields concluded that the average improvement in the oil recovery factor is about 12 per cent for sandstone reservoirs and as high as 17 per cent for carbonates. Moreover, about 71 per cent of the injected CO_2 (on average) remains in the reservoirs while back-produced[4] CO_2 is recovered and re-injected.

The next step – although a major one – is to transfer this decade-old practice from onshore to offshore, using industrial rather than natural sources of CO_2.

The North Sea and even parts of the Norwegian Sea are regarded as potentially suitable targets, because numerous oil fields, gas processing sites and CO_2 sources are relatively concentrated when compared with other offshore regions around the world.

But where will the CO_2 come from?

[1] 'Miscible' refers to the ability of CO_2 to mix with the oil.

[2] In the USA 32 million tonnes of CO_2 are acquired each year from natural sources and 11 million tonnes per year from industrial sources.

[3] Statoil commissioned SINTEF to perform this study.

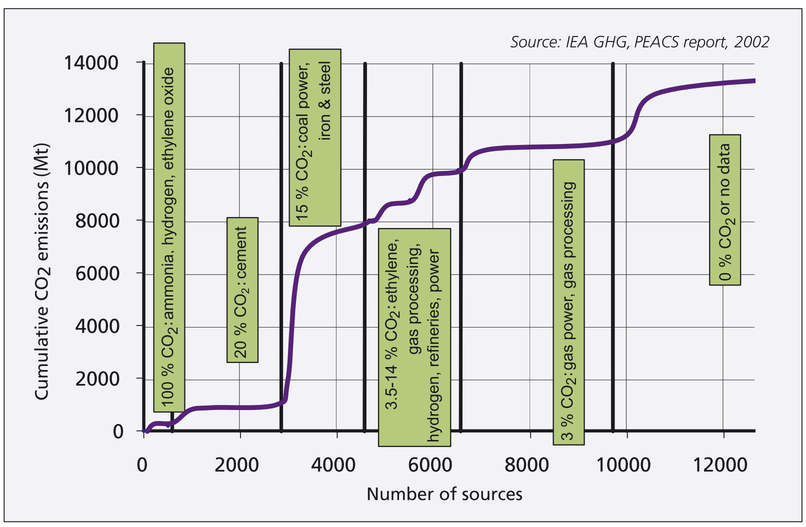
[4] Injected CO_2 returning to the surface as part of the well stream.

Industrial sources and transport

Statoil is investigating the use of local carbon dioxide sources and the possibilities afforded by ship transport

The world's industrial sources can be classified according to their CO_2 concentration, and the costs of capturing high concentration sources are usually lower than those for low concentration sources.

Graph of CO_2 emissions versus number and types of sources.



The most prolific sources are ammonia plants, hydrogen plants, gas processing centres, cement factories, and iron and steel blast furnaces.

Another source for Statoil is its own gas processing sites (e.g. Sleipner and Snøhvit), where the gas consumer has already paid for the CO_2 capture.

But how would the CO_2 be transported to the fields?

On land, much CO_2 is transported via pipelines and is thus a proven technology[5].

This means that the adaptation of present and new pipelines systems is a feasible proposition in parts of the North and Norwegian Seas. However, another serious contender is the shipment of CO_2 in tankers

[5] About 90 million tonnes/year of CO_2 was transported by pipeline in the USA, according to an IEA Greenhouse Gas R&D Programme report in 2001.

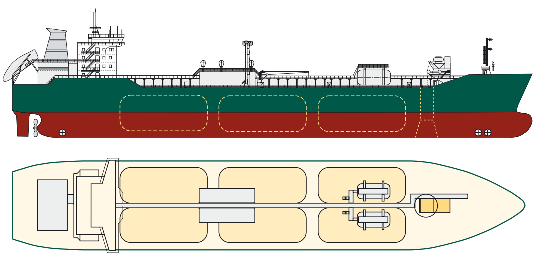
that are somewhat akin to those for transporting liquefied petroleum gas (LPG). In certain cases shipping may prove to be the cheaper alternative and will certainly be the more flexible of the two solutions.

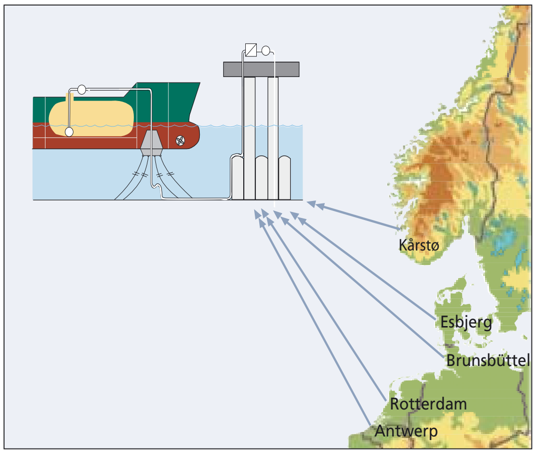
Statoil, SINTEF, Vigor AS and the Teekay Shipping Corporation[6] have just completed a research project aimed at designing a suitable vessel. The planned ship is 177 metres long by 31 metres wide, and contains 4 to 6 tanks capable of holding 20 000 cubic metres of liquefied CO_2 at around 7 bara and a temperature of - 50 ºC. One notable innovation is the development of equipment for directly discharging liquefied CO_2 at production platforms. The ship is also designed as a multi-purpose carrier suitable for transporting LPG and similar products.

Having weighed up the relative costs of initially supplying about 10 million tonnes of CO_2 by pipeline or ship, Statoil believes that both alternatives could be involved either separately or in combination.

But what about the technical and economic viability of offshore CO_2-based improved oil recovery?

[6] Formerly the Statoil-owned Navion company.





The ship (left) and map (right) of possible shipping routes around the eastern North Sea coastline.

Carbon dioxide-based improved oil recovery

Detailed screening studies show that several Statoil-operated fields may be suitable candidates

Over the years, Statoil has made enormous strides in improved oil recovery processes, not least the injection of water and natural gas to sweep more oil out of reservoirs (e.g. WAG[7]) and the use of bacteria to mobilize more oil from pore surfaces (MIOR[8]). The IOR potential for Statoil-operated fields is thought to be significant, particularly in the Tampen and Halten production centres off the southern and mid-Norwegian coast.

The possibility of using CO_2 instead of natural gas has long been discussed, but it is only during the last five years that the topic has received rigorous attention. The question is not whether CO_2-based IOR is feasible – this has already been proved on land – but whether it is viable for the specific conditions encountered in the North Sea.

The general principle is broadly the same as that for natural gas-based techniques, bearing in mind that CO_2 under elevated pressure and temperature is far denser than natural gas. After natural (primary) depletion[9] and (secondary) water injection, CO_2 can be injected into reservoirs where it mixes with the remaining oil and pushes a bank of additional oil towards production wells. CO_2 injection is sometimes referred to as a tertiary recovery process.

Many of the determining factors are common to any CO_2-based IOR project whether on land or at sea: others, however, are peculiar to the offshore operating environment.

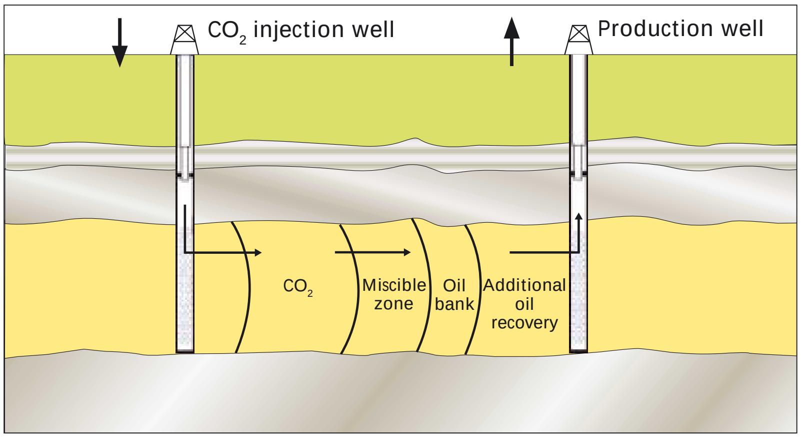
On one side of the equation is cost, where gross and net values of additional oil have to be balanced against operational and investment expenditure. Examples include the importation of vast quantities of CO_2, its mode of transport, and the distances involved. Platform modifications also come into the picture, including the construction of production and injection systems and facilities for handling back-produced CO_2.

On the other side of the equation are technical considerations; for example, well coverage and drainage areas,

[7] WAG – Water-Alternating-Gas.

[8] MIOR – Microbial Improved Oil Recovery.

[9] In the North and Norwegian Seas water injection is carried out straight away, as natural depletion is relatively ineffective.

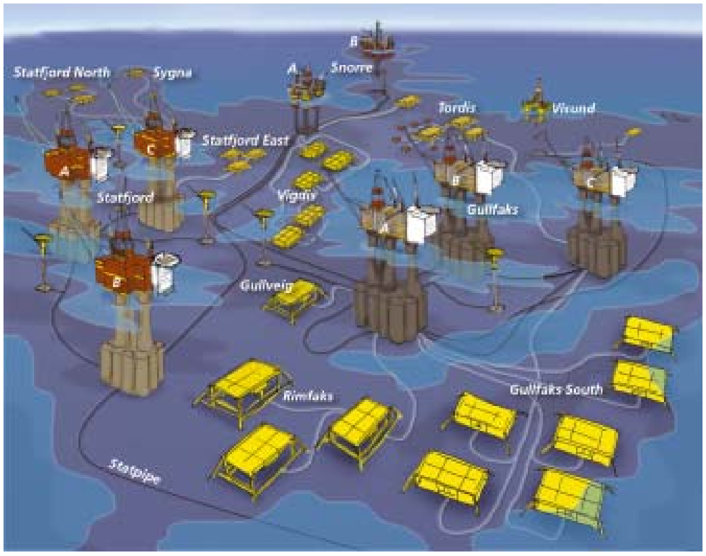


Principle of CO_2-based improved oil recovery.

bearing in mind that distances between offshore wells are far greater than their onshore counterparts.

Other issues concern the ways in which the physical and chemical characteristics of the reservoir rocks and fluids may be affected by CO_2 and the influence of recovery processes and drainage strategies used earlier in the life of a field.

The eventual challenge of injecting CO_2 through subsea wells (i.e. those installed on the seabed) must also be taken into account now that subsea IOR is much in focus.



The Tampen area of the North Sea, showing the Gullfaks platforms (A, B and C) and satellites flanked by Stafjord (left) and Snorre (upper). (Illustration: Thor Oliversen.)

And in some cases there is a possibility of CO_2 infiltrating natural gas, and weak carbonic acid corroding pipe work and pipelines.

The most important aspect, however, is the potential cost-effectiveness of CO_2-based IOR compared with other recovery processes.

Taking all of this into account, it is clear that the importation of a land-based practice into the offshore arena cannot be undertaken lightly. Even so, there are certain technical advantages: CO_2 increases miscibility, which leads to improved displacement efficiency; its high density results in better sweep efficiency; and the consequent swelling of the oil improves mobility. Oil production is also generally high when the conditions are right.

Screening evaluations have been performed on numerous Statoil-operated and partner oil fields, each of which has been categorized on a scale ranging from 'promising' to 'inappropriate'.

As expected, reservoir performance simulations show that there are considerable variations in the amounts of extra oil that could be produced. In the worst cases there is almost no benefit at all, whereas in the best cases additional production could amount to some 10 per cent of the original oil in place.

The challenge facing Statoil's reservoir experts is to reduce the economic and technical risks by improving the precision of reservoir simulation, and discussing the pros and cons of implementation with asset teams and partners.

Of those fields falling into the 'promising' category, the Statoil-operated Gullfaks field is the most extensively studied candidate for a CO_2-based MWAG pilot (M = Miscible).

The field is located on the western flank of the North Viking Graben (Norwegian sector, North Sea), and largely comprises highly faulted and compartmentalized marine and fluvio-deltaic sandstone reservoirs belonging to the prolific Middle Jurassic Brent Group. Production at Gullfaks began in 1986 and the field has 112 wells drilled from three production platforms.

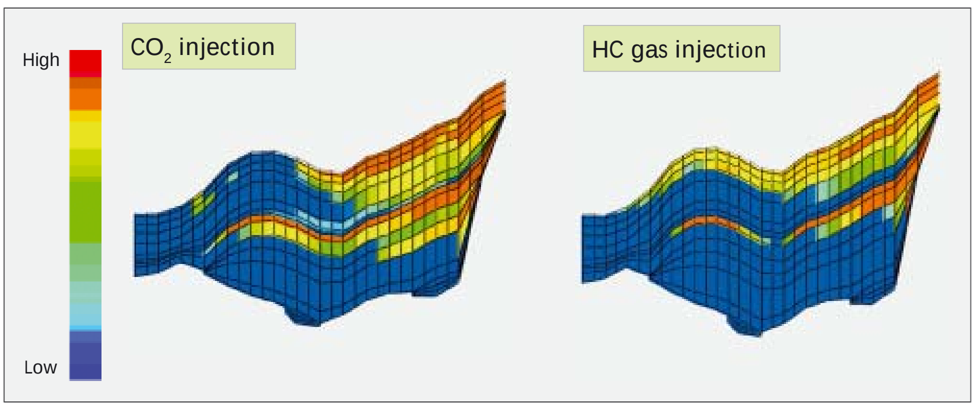


Illustration of gravity effects: a plot of gas saturation during CO_2 injection (left) versus a plot of gas saturation during hydrocarbon gas injection (right). Note that CO_2 injection affects a far larger volume of the simulated reservoir than its natural gas counterpart, particularly in the deeper intervals. It thus has greater vertical sweep efficiency.

TOMORROW’S WORLD

Statoil is working towards a vision of carbon dioxide-free energy from fossil fuels and excellence in environmental stewardship.

Over the years Statoil has developed a vision of where oil and natural gas may be headed. Although subject to market and political fluctuations, a plausible 21st century scenario is that fossil fuels will remain the prime energy sources while electricity and hydrogen will increasingly become the energy carriers. Our aim is to prepare for these eventualities and provide clean, energy-efficient solutions for our customers.

Compared with oil, natural gas is cleaner, lighter, and burns more efficiently. It can also be distributed through a network of pipes in a far less conspicuous fashion, and is the fastest growing fossil fuel and the primary choice for electricity generation. With an ever-increasing abundance of natural gas, it is hardly surprising that the company sees this as the source for both electricity and hydrogen*. In both of these cases the gas has to be decarbonized, which means that our world-class expertise in CO_2 management is destined to play an even greater role.

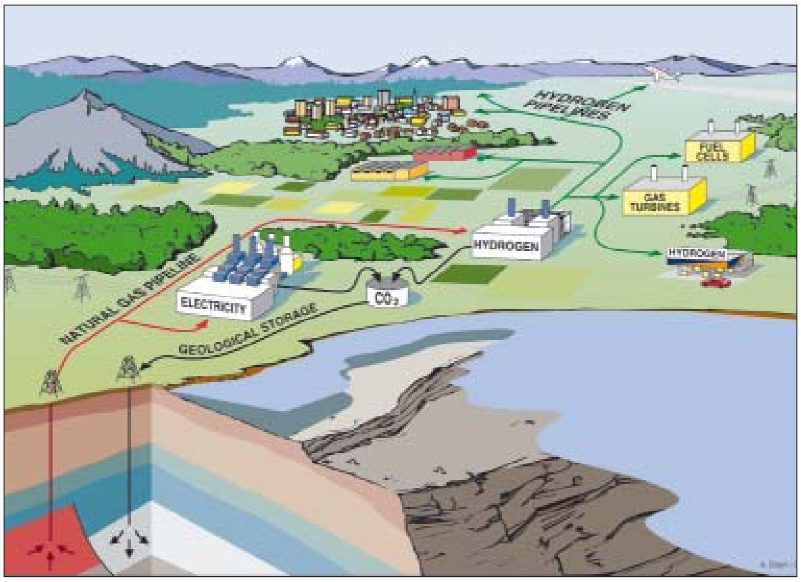
Statoil’s intention is to intensify its efforts in developing and qualifying commercial cost-effective technology for these purposes. Indeed, the possibility already exists for testing CO_2 capture technologies and the efficiency of power and heat generation from natural gas using existing experimental facilities at the Research Centre.

We also hope to take part in the development of a hydrogen demonstration plant (including a reformer) for hydrogen production, storage, and delivery for fuel cells incorporated in cars and buses.

Recognizing the need for stronger national and international public policies and educational efforts to accelerate the process, we are stepping up our campaign to highlight the desirability of such developments through the media, specialist seminars and conferences, trade exhibitions and the like.

And realizing that no petroleum company can go it alone, much of our research will be done with others through joint ventures with industry and governments.

To promote innovation, the group has recently established a business unit for ‘new energy’, which is continually on the look out for industrial applications arising from the latest research results.



Cartoon illustrating how natural gas can be used to manufacture two CO_2-free energy carriers - electricity and hydrogen. Note the CO_2 capture plant from which the CO_2 can be injected into subsurface formations for long-term storage and/or CO_2-based improved oil recovery. (Illustration: Arnfinn Olsen and Olav Kårstad, c 1980.)

Its mandate is to develop opportunities in sustainable production and renewable energy – including those arising from CO_2 – as well as satisfying the emerging electricity and hydrogen economy.

The unit has already enjoyed considerable success as a business catalyst for renewables such as bio fuels, electricity generated from a tidally driven turbine (akin to a submerged windmill), and combined heat and power production using highly efficient micro-energy stations.

In short, Statoil’s plan is to reduce the costs of CO_2 capture; generate electricity and hydrogen from natural gas; consolidate its position in renewables; and demonstrate the wisdom of its chosen path to the authorities and society alike.

*Statoil is also engaged in developing the next generation of gas-to-liquids (GTL) technology to yield synthetic petrol and environment-friendly diesel. A forthcoming memoir on this subject is under discussion.

By now it should be abundantly clear that Statoil’s aspiration in sustainable development and environmental protection is to be among the best. Our present achievements suggest that we are well on the way.

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The following material is also available:

Milestones 2001
Milestones 2002
Milestones 2003

R&D Memoir 1 – Flow Assurance (2002)
R&D Memoir 2 – Offshore Geophysical Methods (2002)
R&D Memoir 3 – Offshore Produced Water Management (2003)
R&D Memoir 4 – Geological Reservoir Characterization (2003)
R&D Memoir 5 – Carbon Dioxide Capture, Storage and Utilization (2004)
R&D Memoir 6 – Liquefied Natural Gas (in preparation)

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ExxonMobil

Meeting the Challenges in Design and Execution of Two High Rate Acid Gas Injection Wells

Glen Benge
E. G. Dew

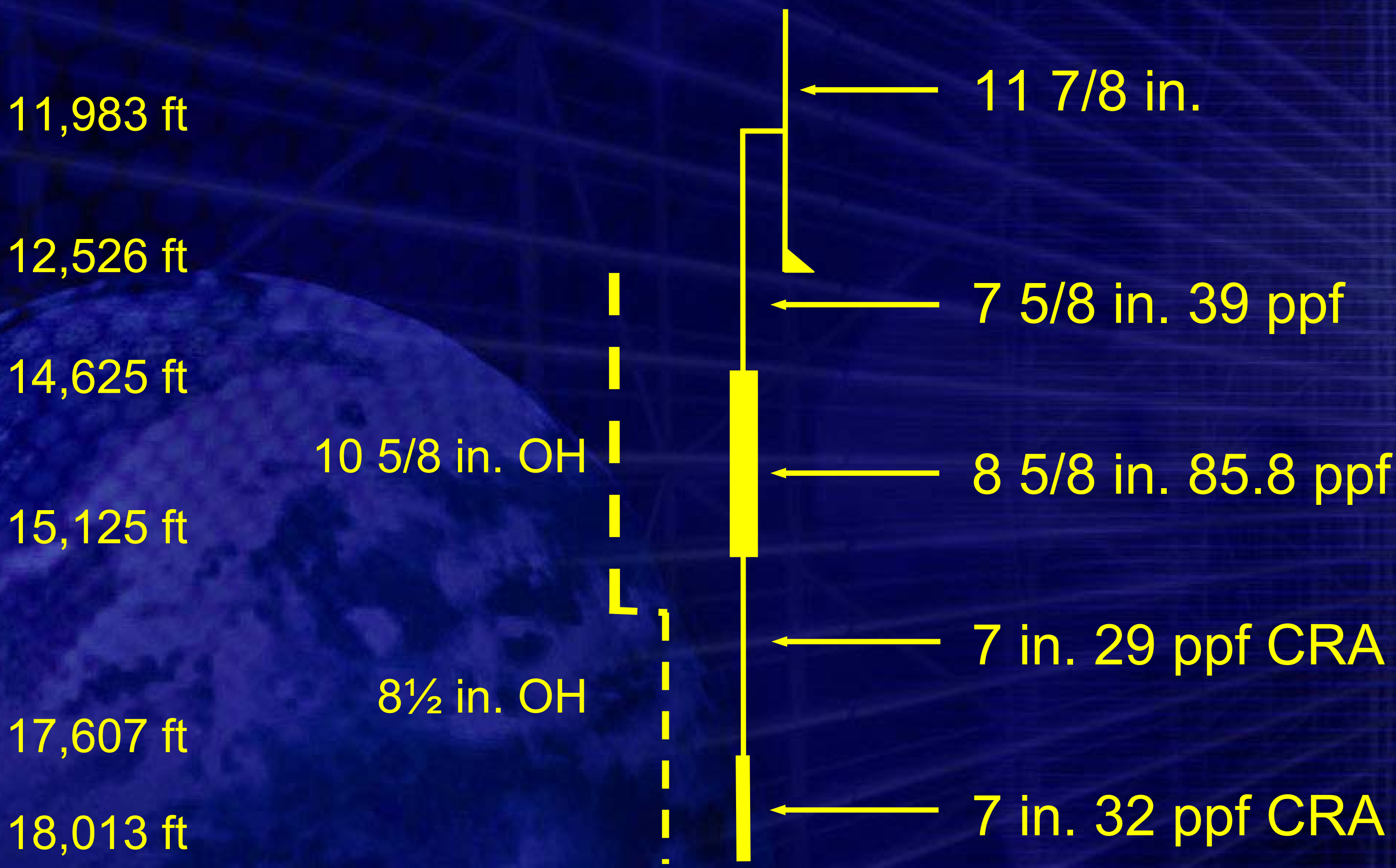
Design Basis

- 100 mmscf/day gas rate capacity, 65 mmscf/d gas planned rate
  - 65 % H_2S
  - 35 % $C0_2$
- Potential movable salt formation

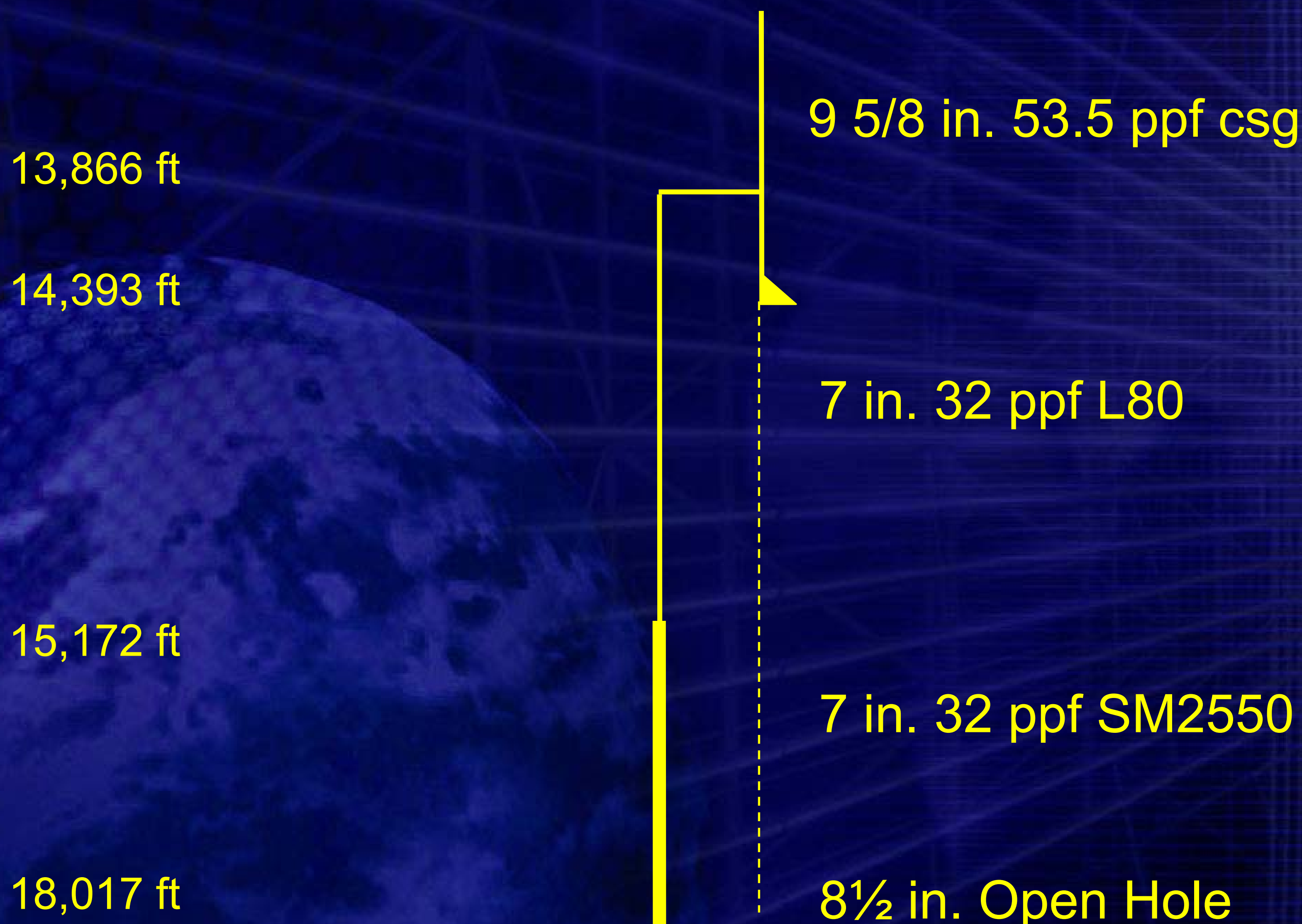
Design Basis

- Well TD - 18,000 ft
- Bottom hole temperature - 300 °F
- NAF drilling fluid
  - 10.8 - 12.2 lb/gal

Liner Program - AGI 3-14



Liner Program - AGI 2-18



Cement Design Basis

- Resistance to CO_2
- Good fluid loss control
- No strength retrogression
- No gel strength development while setting liner top packer

CO_2 Resistance

- CO_2 converts Portland cement to calcium carbonate
- Can obtain resistance by:
  - limiting Portland cement content and reducing permeability
  - eliminating Portland cement

Cement Design Risks

- Portland based system
  - Incorporated specific particle size “diluents”
    - First use of a specialty PSD system in the area
  - Untried system
    - CO_2 resistance tied to low perm and reduced Portland concentration
    - System would not be completely CO_2 resistant
  - Complicated blending

Cement Design Risks

- High alumina cement
  - Not a standard stock item
    - required early commitment
    - no ready market for excess
  - High temp fluid loss additive unavailable
  - Deepest / hottest application of system to date
  - Very sensitive to contamination with Portland

Design Plan

- Portland based PSD system
  - Used latex to further protect cement and lower fluid loss
  - Developed QC plan for blending and additives
  - Design and testing confirmed by multiple labs
  - Plan developed for any future well interventions

Cement Design Results

- High alumina cement
  - Developed a high temp fluid loss additive
  - Better understanding of well volumes
  - Developed QC plan for cement manufacture and handling
  - Plan developed to prevent contamination

Casing Handling - AGI 3-14

- Multiple casing sizes complicated logistics and handling
  - 30 hours to make up and run
    - 16 hours for conventional liners
  - 8 5/8" heavy wall casing proved challenging
    - derrick alignment key point in operation

Casing Handling AGI 2-18

- No salt in well simplified casing design
- No diameter changes
- Only change was from CRA to L80
- 21 hours to make up and run liner

Cementing - AGI 3-14

- Portland based PSD system
  - Water & additives batch mixed prior to job
    - water was used for all field blend lab testing
  - Strength testing at TOL
    - results not showing strength
    - traced to algorithm on UCA

Job Results - AGI 3-14

- Mix water foaming problem
  - two computer mixing systems taken off line
  - lost bulk cement unit due to water in bulk line
  - could not take water through displacement tanks
  - water volume could only be estimated during job
    - had to rely on bbl counters on cement unit for slurry volume

Job Results - AGI 3-14

- Cement volume adequate in spite of losses in bulk equipment
  - cement circulated off top of liner
- Cement evaluation logs showed excellent results

Cementing - AGI 2-18

- High temp fluid loss additive functioned as designed
- Multiple batches of high alumina cement
  - batches blended together and pre-tested at central lab and approved prior to shipment to district
- Washed all bulk equipment
- Same QC procedures used for mix water and laboratory testing

Cementing Results - AGI 2-18

- No issues with cement mixing
- Cement seen in returns from top of liner
- No cement evaluation performed to date

Cementing Summary

- High alumina cement holds an advantage with respect to CO_2 resistance
- Portland based system is advantageous with respect to logistics and material availability
  - current data set is insufficient to confirm improved CO_2 resistance

Lessons Learned

- Alignment of the rig was key to running the heavy weight 8 5/8" casing
- Batch mixing of mix water and adds provided excellent QC and improved on location logistics
- Mixing problems remained in spite of pre-qualifying equipment

Lessons Learned

- New fluid loss add for high alumina cement
- Single blend of high alumina cement simplified planning and operations
- Keying in on basics for both operations was key to success on both wells

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Well Bore Integrity Workshop

- Presentations
  - Hosted on IEA GHG web site
    - www.co2captureandstorage.info
    - Listed under Technical Workshops
    - Notification by e-mail when they are available
  - Detailed report available later
- Please leave your badges!

Well Bore Integrity Workshop

- Launch meeting of the Risk Assessment Network
  - Follow on from London Workshop, Feb 2004
  - Well bore integrity as key activity area
  - *Date:* 23rd/24th August 2005
  - *Location:* TNO-NITG offices in Utrecht, Netherlands
  - Details to follow by e-mail