different forces as indicated in the figure (buoyancy forces, capillary forces, convection etc). Due to (mainly) buoyancy, the CO_2 might invade into the atmosphere.

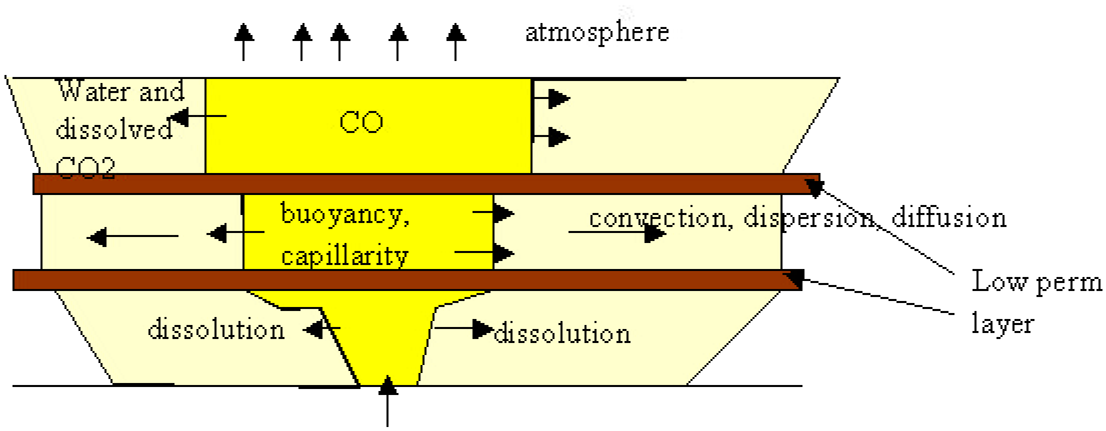

Figure 7 Conceptual model for the shallow subsurface

The dissolved CO_2 in the groundwater may cause heavy metals to become mobile which may contaminate the groundwater in the aquifers. The specific equations that describe the transport and behaviour of CO_2 in the shallow aquifers are given by Battistelli et al (1997), Oldenburg and Unger (2003) and Pruess et al (2001).

In contrast to the shallow subsurface model presented in the first phase of the SAMCARDS project (Wildenborg et al, 2003), the model presented here includes CO_2 flow into the atmosphere and the effect of salinity on CO_2 dissolution. Buoyancy and cappilarity still play a major role.

The model domain is shown in fig. 8 . It is radial symmetric with a depth of 300 m and a horizontal extension of 15,000 m.. The soil surface shows a depression in a radius of 20 m around the center of the domain. The soil characteristics are based on the geology of the western parts of the Netherlands. The soil consists of 4 high permeable layers separated by low permeable layers. CO_2 enters the model through the lower boundary and in the center of the domain with a radial extension R.

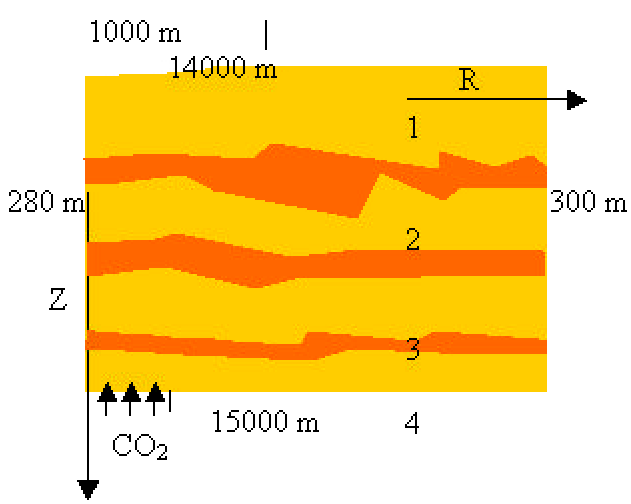

Figure 8 Layering in the shallow subsurface model

Dissolution of CO_2 is included in the model assuming local equilibrium. Advection, dispersion, diffusion and the effect of capillarity are taken into account. There is no natural groundwater flow and the background CO_2 concentration in the groundwater is assumed to be zero. Due to lack of data a temperature in the entire model of 10 degrees Celsius is assumed. The beginning of the calculation is at the time of the first CO_2 arrival after injection: 1300 yr. The total time of the calculation is 4000 yr.

Table 3 Hydraulic properties of layers in shallow subsurface

	High perm layers	Low perm layer
K (m^2)	1.4 10-12	1.4 10-14
λ	2	2
Pe (m)	0.3	2.0
Porosity	0.35	0.4

Table 3 gives the hydraulic properties of the high and low permeability layers in the system. Brooks and Corey type of functions are used to describe the capillary pressure-saturation relations, while the relative permeability-saturation relationship are given by the ones proposed by Burdine (Wipfler, 2003). λ is a dimensionless parameter that controls the steepness of the Brooks-Corey relation. Pe is the entry pressure for the different soil types. The layers are assumed to be incompressible.

The distribution of the salinity is based on the Dutch DINO groundwater database which shows a linear profile of 0 mg/l at 50 m below ground level to 1000 mg/l at 300 m below ground level. Fluid properties are given as known functions of salinity, CO_2 concentration, temperature and pressure.

Transport of CO_2 in the atmosphere is described by a convection-dispersion equation. Only density driven flow and diffusion will be considered. The wind velocity is approximately zero.

Controlling parameters

Based on the conceptual model the parameters that need to be varied in addition to the ones already included in the Monte Carlo simulation for the reservoir-seal model are the ratio of the permeabilities of the different soil types, and the ratio of the entry pressures. The range of variation still has to be determined.

Required output

The output that should be obtained from the model calculations will have to describe the development of the CO_2 concentration in time and space. However, it will be impossible to handle the complete spatial and temporal distribution of this concentration. This distribution will be approximated by four numbers:

1. the maximum CO_2 concentration in the atmosphere;
2. time required to reach this maximum;
3. characteristic time of decline from maximum CO_2 concentration;
4. the dispersion constant.

With these four numbers, a time-dependent Gaussian spatial distribution of CO_2 can be constructed. A similar approach can be defined for the concentration in the shallow aquifer.

Status

The first modeling results obtained from LBNL are now being evaluated. In contrast to what was reported in the Phase 1 report (Wildenborg et al, 2003), CO_2 spreads much further in the aquifer and enters the atmosphere. That has to do with an error in the definition of the CO_2 flux boundary conditions in the previous simulations. The first results obtained now indicate a strong dependence of the results on the calculational grid used. Further discussions with LBNL are required to solve that problem.

2.1.1.6.2.4 Probabilistic PA model

General considerations.

In the previous status report (Wildenborg et al, 2003) the data flow for a particular scenario was described. When data have been processed in the various compartments they will have been transformed into a CO_2 concentration field which depends on time. Each particular set of initial and boundary conditions leads to such a time dependent field.

These data have to be dealt with in a probabilistic way. The reason is obvious: there is no infinitely precise information on the subsurface available. Although the methodology developed here should be applied to a *specific* site, and CO_2 will be stored into a part of the subsurface that is relatively well-known, the information is still incomplete.

The insufficient knowledge of a specific site has to be transformed into a probability density function (pdf) of the crucial physical and chemical quantities that describe the CO_2 distribution in space and time. Parameter values have to be drawn from various distributions, which will easily lead to at least some thousand cases that have to be investigated (see also the section on the reservoir-seal model). None of these cases will represent the site as is, and a probabilistic approach has to be adopted.

The sheer magnitude of the output of the simulations required to address the problem of parameter uncertainty forces us to present the contents of this data in a compact way. A minimum set of numbers to accomplish this is four:

1. the maximum CO_2 concentration in the atmosphere;
2. time required to reach this maximum;
3. characteristic time of decline from maximum CO_2 concentration;
4. the dispersion constant.

Likewise, the same minimum set of numbers must be determined for the impact on groundwater of a CO_2 hazard.

Consequently, the effect of parameter uncertainty on the CO_2 distribution in the atmosphere or the shallow groundwater will be summarized in a pdf of four variables.

Probabilistic issues.

It was decided early-on that probabilistic inferences would be made with help of the PARDENS tool, developed by Wojcik and Torfs. (2003a, 2003b)
In the tool the user possesses freedom to choose the balance between the data wielding local influence and influencing on larger scale. That is done by choosing a value of the "globality" parameter. Then, an iterative procedure gives the best fit, and returns a value ("validcrit") of a certain functional to be maximized in the iterative process (Wojcik and Torfs, 2003a, 2003b).

It might be thought that the *optimum fit* of a dataset is governed by the globality parameter giving maximum "validcrit". This view is not taken here. It is true that there exists an optimal choice for a pdf once the globality parameter has been chosen, but the choice of this parameter itself may be guided by scientific considerations. In fact, constructing a pdf is not a "one-solution-problem".
For example, consider the following problem:

1. two different physical mechanisms brought about certain data. A pdf consisting of two "humps" rather than one overall Gaussian may be considered if it is known that different mechanisms work in different parameter ranges.

2. the same data, but nothing is known about the mechanism(s) that brought them about. In fact, only the order of magnitudes of variations in the parameters is “certain”. In such a case looking for an overall Gaussian distribution might be the best translation of the prior knowledge (Jaynes, 2003).

In a scientific context producing PDFs is not the responsibility of the mathematics alone, even though mathematicians may come up with tools to do so.

Therefore, it is assumed that different values of the globality parameter give equally likely PDFs. For subsequent manipulations all of them will be used as a check on how (in)sensitive certain answers will be on the chosen pdf. In case of large sensitivity, a choice as to the globality parameters to pick has to be made. This philosophy conforms to a Bayesian viewpoint.

The PDFs are constructed with an eye on subsequent questions to be answered. The theoretical tool to be used to do the answering is Monte Carlo simulation.

Each and every question must be answered from the PDFs that have been constructed, and correlations that have been “spotted “ during construction must be taken into account. Usually, answering questions boils down to integrating the PDFs over a part of parameter space that is bounded in an intricate way. Analytical methods are not the method of choice, therefore, and we have to resort to Monte Carlo techniques.

In the PARDENS tool there is the explicit possibility to sample points from a (given, constructed) Parzen density. Wit help of this and logic binary operations performing Monte Carlo computations is surprisingly easy (and not too time-consuming in the cases treated so far).

The role of the PDFs is auxiliary. They are used in the computations. In the type of problems of interest, there is no possibility of making a picture of the distribution (which would be 5-dimensional in the case described). The best one could do is to make the various 1D marginal distributions and picturize them.

Application

In the section on the reservoir-seal model, the stochastic simulation for the leaking seal mode is described.

1000 runs were made with quantities drawn from the parameter PDFs described in that section. 983 runs gave useable answers,. Just for experimental purposes a 3D probability distribution was constructed out of “build-up time”, “decline time” and maximum CO_2 flux, three quantities that could be constructed from the grid results of the 983 runs.

Now the question is asked: “what is the probability that the maximum CO_2 flux is more than one standard deviation above the average value?”

In answering this question 40,000 samples were randomly drawn from the constructed pdf. This was repeated for 10 different “globality” parameters evenly distributed in the range 0.1-0.999.

Table 4 Effect of globality parameter on probabilities

globality	Prob (max CO_2 flux > average + 1 σ)
0.1	0.178
0.2	0.178
0.3	0.176
0.4	0.175
0.5	0.175
0.6	0.174
0.7	0.171
0.8	0.165
0.9	0.159
1.0	0.160

Table 4 shows the results of this exercise. It appears that the results are not critically dependent on the globality parameter, and that the probability is somewhere in the range 0.16-0.18. The results in the last two lines resemble what might be expected from a 1D Gaussian distribution. Whether this does mean that the distribution of the max. CO_2 flux is a Gaussian, independent on the distribution of the other variables, could be further investigated this with the PARDENS tool. However, this matter will not be pursued here.

2.1.1.7 Results and Discussion

In the period reported here, tools have been developed that allow a consistent analysis of the FEP database, and hence the development of methods to identify groups of scenario defining FEPs. Testing during a two-day workshop in June 2003 showed, that small adjustments in both the tools as in the FEP database are still needed. With these adjustments the base case scenario and variant scenarios can be defined.

Monte Carlo simulations with the reservoir-seal model have been carried out for some 1,000 combinations of parameter values. No major problems were encountered in carrying out these simulations.

Simulations for the shallow subsurface model, including the atmosphere, are carried out by LBNL. The first results of these simulations are now being evaluated and discussed. These results indicate that there is a grid convergence problem, i.e. results are still dependent on spatial resolution of the model. Monte Carlo simulations with the shallow subsurface have not been carried out yet. They are waiting for a solution of the grid resolution problem, since Monte Carlo simulations cannot be carried out for a fine grid, because of large computer times required.

The probabilistic tool that will form the basis of the Performance Assessment model has been finalized. The first tests show that the tool is easy and fast to work with. One of the major parameters in the model is the globality parameter that determines the “radius of influence” of the different data points. Choosing this parameter is a question of expert judgment. It needs to be seen how sensitive answers of the probabilistic tool are for the choice of this globality parameter.

2.1.1.8 Conclusion

Based on the results of the two-day workshop in June 2003, we can conclude that the analysis of the FEP database in order to define groups of scenario defining FEPs should be possible in a short time.

Carrying out Monte Carlo simulation with the reservoir-seal model for the leaking seal mode did not pose any problem. It is expected, that the same will be true for the leaking well mode and the leaking fault mode.

Monte Carlo simulation with the shallow subsurface model has not been carried out. These simulations will be carried out by LBNL. The progress of this work is a bit hampered by the logistics of discussing results and possibilities with co-workers of LBNL. The first results, that are being evaluated now, show grid dependence of the CO_2 distribution for this shallow subsurface model. This problem has to be resolved before Monte Carlo simulations can be carried out.

The probabilistic Performance Assessment model is operational and well documented. First tests show that the model is easy to work with and require little CPU time.

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2.1.1.10 Publications

None at this time.

2.1.1.11 Bibliography

None at this time.

2.1.1.12 List of Acronyms and Abbreviations

None at this time.

2.1.1.13 Report Appendices

Appendix A: FEP analysis

FEP analysis (Fig. 9) starts with a comprehensive inventory of all possible FEPs that may influence the safety of the sequestration facility. As the inventory is essentially not case specific this leads to a huge number (in the order of hundreds) of FEPs. This large number needs to be cut down to a tractable amount. The reduced set of FEPs makes it possible to define relevant scenarios. This is the objective of the FEP analysis.

The first two stages of the FEP analysis, i.e. identification and classification, are generic. The ranking, however, is case specific and depends on the terms and conditions defined in the assessment basis. For each HS&E study the FEPs need to be ranked by experts.

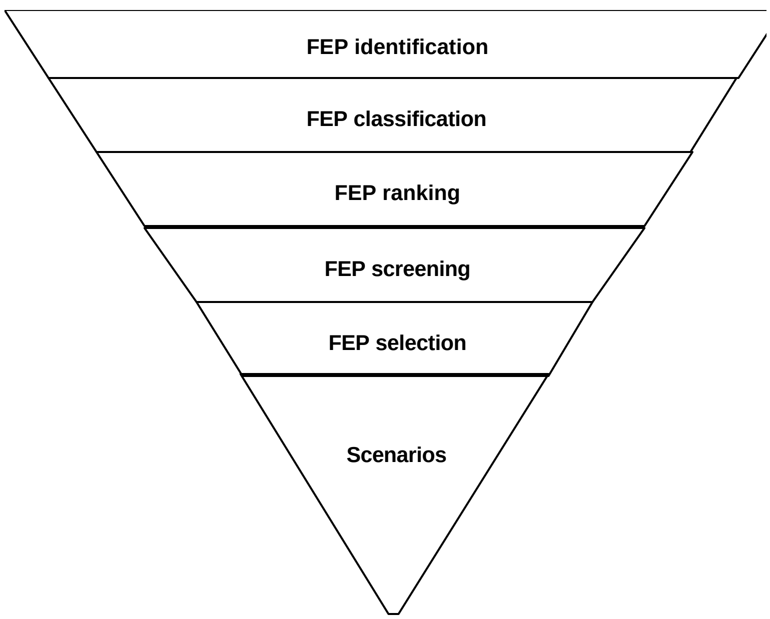


Figure 9 Scheme of stages in the FEP analysis.

The fourth step involves screening out of the FEPs, which appear to be irrelevant for the HS&E assessment. FEPs can appear to be irrelevant for many reasons. Examples are:

low likelihood
low impact
irrelevant time scale.

The product *risk = probability x impact* is used to select a restricted number of FEPs that subsequently are qualified as either *base-case* or *scenario defining*. Base-case FEPs will be included in all subsequent scenarios, including the base scenario. They have been qualified as “Very likely” (table 5). Scenario defining FEPs are FEPs with a high and medium risk other than base-case FEPs.

Table 5 Semi-quantitative risk matrix.

Potential Impact	*Significant*	High risk	High risk	Medium risk	Low risk
	Marginal	Medium risk	Medium risk	Medium risk	Low risk
	Negligible	Low risk	Low risk	Low risk	Very low risk
		Very likely	*Likely*	*Unlikely*	*Very unlikely*
		Likelihood			

By default, the features have a probability of 'unity' and are defined as base-case FEPs. They do not need to be evaluated during the ranking procedure, as they are always included in all scenarios. They are the basic input parameters for the subsequent numerical modeling phase.

A variant scenario is defined as a possible evolution of the sequestration facility. It includes all FEPs from the base scenario and, in addition, one or multiple scenario defining FEPs.

Often the number of scenario-defining FEPs is too large to define a restricted number of variant scenarios. Out of 10 scenario-defining FEPs more than 1,000 variant scenarios (210) can be defined. A further reduction of the number of scenario-defining FEPs might be opportune. This is achieved through grouping FEPs with similar effects on the underground facility and its surrounding environment. FEP interactions are accounted for during this process. Initiating events and processes that may result in CO_2 bypassing the boundary of the sequestration facility (i.e. the seal) are distinguished from other FEPs.

Selection of combination(s) of FEP groups is the last stage of the FEP analysis. This stage comprises the formation of a limited number of scenarios that describe the possible future evolution of the sequestration facility. A scenario is build-up by a number of scenario elements. Scenario elements are alternative future states that each model compartment may adopt and that affect the integrity of that compartment. The model compartments under consideration are: reservoir, seal, well zone, fault zone, overburden, fresh-water zone, marine and atmosphere (Fig. 10).

<u>Scenario formation</u>

The approach pursued here is to divide the sequestration facility into several components: reservoir, seal, well, fault, overburden and biosphere, termed model elements, and then to postulate a comprehensive set of alternative states which each model element may adopt that affect the integrity of that compartment.

The stages to follow are:

- Define potential model elements comprising specific FEP groups.
- Construct an influence diagram or interaction matrix showing dependencies between model elements (see Fig. 11 as an example).
- Define a comprehensive set of states for each model element.
- Form a model element state tree in which each combination of states defines a potential scenario. The base scenario comprises of base case FEPs that have been defined during the ranking process. The base case refers to the most probable development of the CO_2 sequestration system. Variant scenarios comprise of scenario defining groups of FEPs. Variant scenarios are alternative features, events and processes, about which considerable uncertainty exists.
- Screen the combination of model element states by rejecting non-physical and unimportant combinations to arrive at a set of scenarios for consequence analysis.
- Assign weights (alternatively 'degrees of belief' or probabilities) to each model element state taking account of states of other model elements via the influence diagram (see Fig. 12 as an example) and hence derive scenario probabilities.

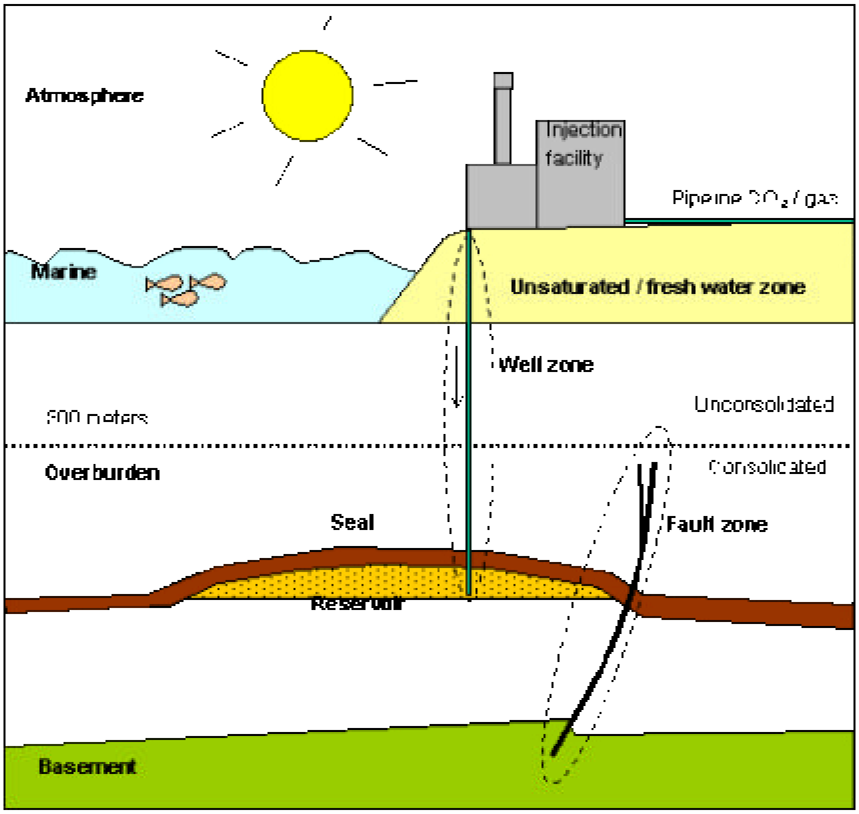


Figure 10 Schematic representation of model compartments.

The main advantages of the top-down approach are that the model element states can be defined to be intrinsically comprehensive, and thus weights ('degrees of belief' or probabilities) can be coherently assigned using expert judgment.

An important part of the developmental work is directed to a computerized scenario database and is of special importance for constructive iterations, review and transparency of the whole scenario formation process. In this way the complete chain of scenario development can be documented.

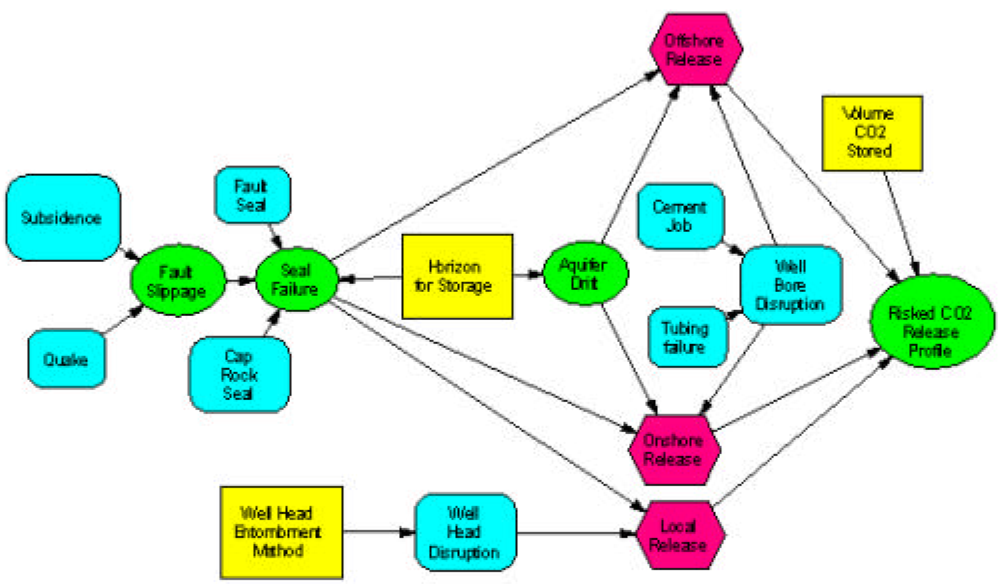


Figure 11 Example of an influence diagram.

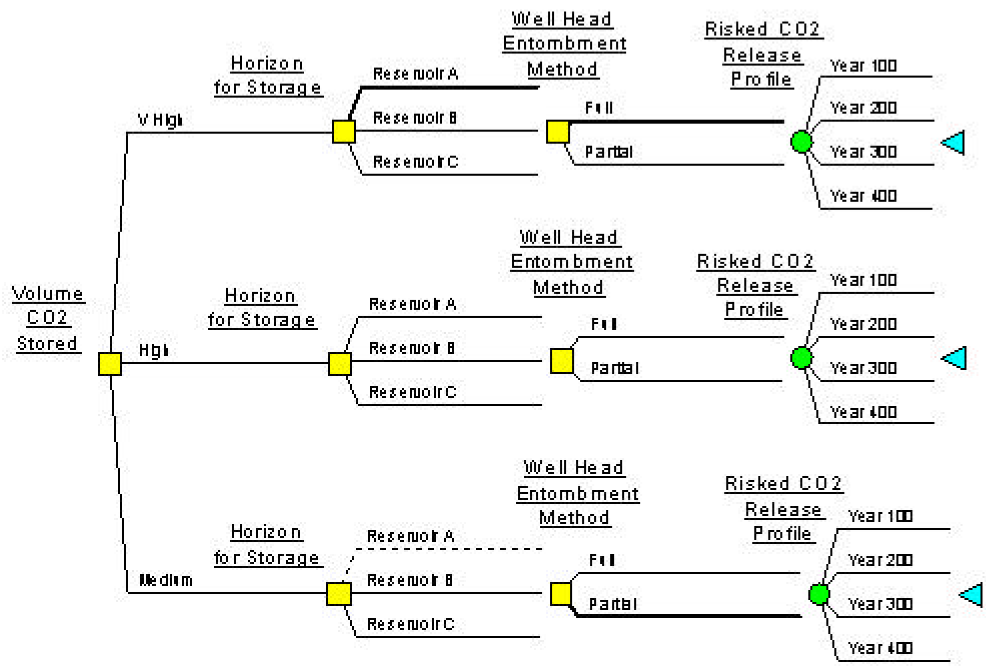


Figure 12 Example of a tree diagram.

Appendix B: Scenario Workshop Document

This document serves as an introduction to the scenario workshop of 18 and 19 June 2003 organized by TNO-NITG. The workshop will focus on the last stages of the FEP analysis process: FEP grouping and scenario construction. The workshop is a follow-up of the FEP workshop held on 4 December 2002.

Background

To determine whether geological storage of CO_2 is a viable option to contribute significantly to the Kyoto targets it is essential to show that suffic iently large amounts can be stored safely and with acceptable costs. It was recognized that the long-term safety required more research to make underground CO_2 storage acceptable for governments, public and environmental organizations.

Introduction

The currently ongoing SAMCARDS project (Wildenborg et al, 2003) focuses on the safety assessment of underground storage of CO_2. A methodology for the HSE (Health, Safety and Environment) risk assessment of CO_2 sequestration is being developed, and will be demonstrated in practice for two real CO_2 sequestration cases. The methodology under development is new in the CO_2 application area. It is based on the scenario approach (Fig. 13) which has been successfully applied in safety assessment studies (NIREX, 2000; PROSA, 1993) of hazardous waste disposal.

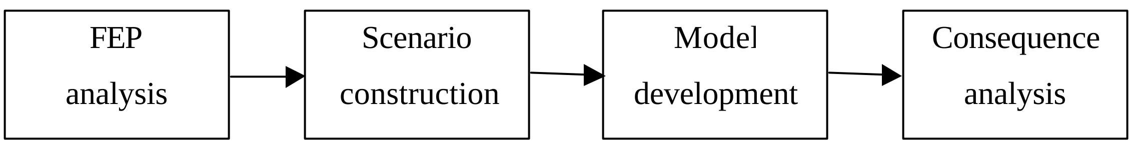


Figure 13 The main phases of the scenario approach for risk assessment.

During the workshop we will apply the newly developed meth od in practice. The workshop will particularly focus on the first stages of the scenario approach: FEP analysis and scenario construction.

The objective of the workshop is twofold:
Performing several exercises on the basis of the selected FEPs in the previous workshop to define a limited number of future risk scenarios. FEPs will be grouped into scenario elements. Risk scenarios will be defined by combination of several scenario elements.
Testing the methodology and tools developed by TNO-NITG to examine the applicability of the proposed method and, possibly, to improve certain aspects of the method.

General approach

The core of the scenario approach (Fig. 13) is a systematic development of a limited number of scenarios that describe the potential long-term evolution of a CO_2 sequestration site. Once the scenarios have been defined they need to be evaluated in modeling terms i.e. development of conceptual models and related model codes. The developed models are used to quantitatively assess the consequences with respect to HSE.

The basic elements for the development of scenarios are the *FEPs* (NIREX, 2000; PROSA, 1993). The term FEP is an acronym for Feature, Event and Process. A scenario consists of an assemblage of interdependent FEPs that describe the long-term fate of the sequestration system.

The development of an appropriate set of scenarios comprises many stages as illustrated in Fig. 14 . The first stage involves a comprehensive inventory of the FEPs that are related to the long-term fate of the sequestered CO_2. As this inventory is essentially not case specific this leads to a huge amount (in the order of hundreds) of FEPs. This large number needs to be cut down to a tractable amount. The reduction of FEPs makes it possible to define relevant scenarios. This is the objective of the FEP analysis.

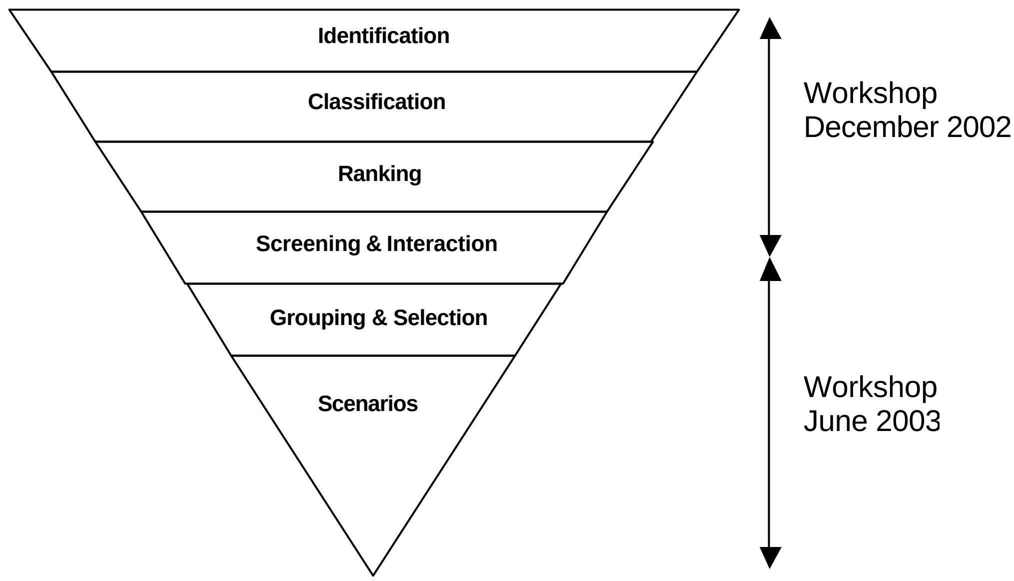


Figure 14 Scheme of stages of the FEP analysis.

The FEPs need to be evaluated by experts using the "assessment basis". The assessment basis specifies HSE risk criteria, the sequestration concept, site characterization and other boundary conditions for the CO_2 sequestration case under study (enclosure 1). During the evaluation the probability and potential impact of the FEP with respect to the assessment basis is estimated in semi-quantitative terms. Screening and selection will lead to a tractable number of FEPs that are input to the forecast scenarios.
Workshop approach

During the workshop of 4 December 2002, the four three stages of the FEP analysis procedure have been highlighted (Fig. 14). The current workshop in June will continue with the screening and will focus on the last three stages: interaction, grouping and scenario construction. Starting point is a collection of FEPs that were selected as "scenario defining FEPs" in December 2002 (enclosure 2). These FEPs need to be evaluated further in order to construct scenarios. FEPs that were selected for the base case (reference scenario) will not be part of the present workshop.
Possible interdependence between the scenario defining FEPs will be analyzed for each compartment. The FEPs will be grouped into scenario elements on the basis of interaction and common classification attributes in the FEP database. The scenario elements will be combined into risk scenarios. Finally the model representation of the scenarios will be discussed. During the workshop we will not reflect on the mathematical modeling of scenarios and subsequent consequence analysis.

Day 1

The results of the first three stages of the FEP analysis process elaborated during the workshop of December 2002 will be discussed. After the plenary session, the participants will be divided over disciplinary groups. During the group sessions the interdependence between FEPs will be discussed. At the end of the day the participants will group the scenario defining FEPs into scenario elements (Fig. 15).

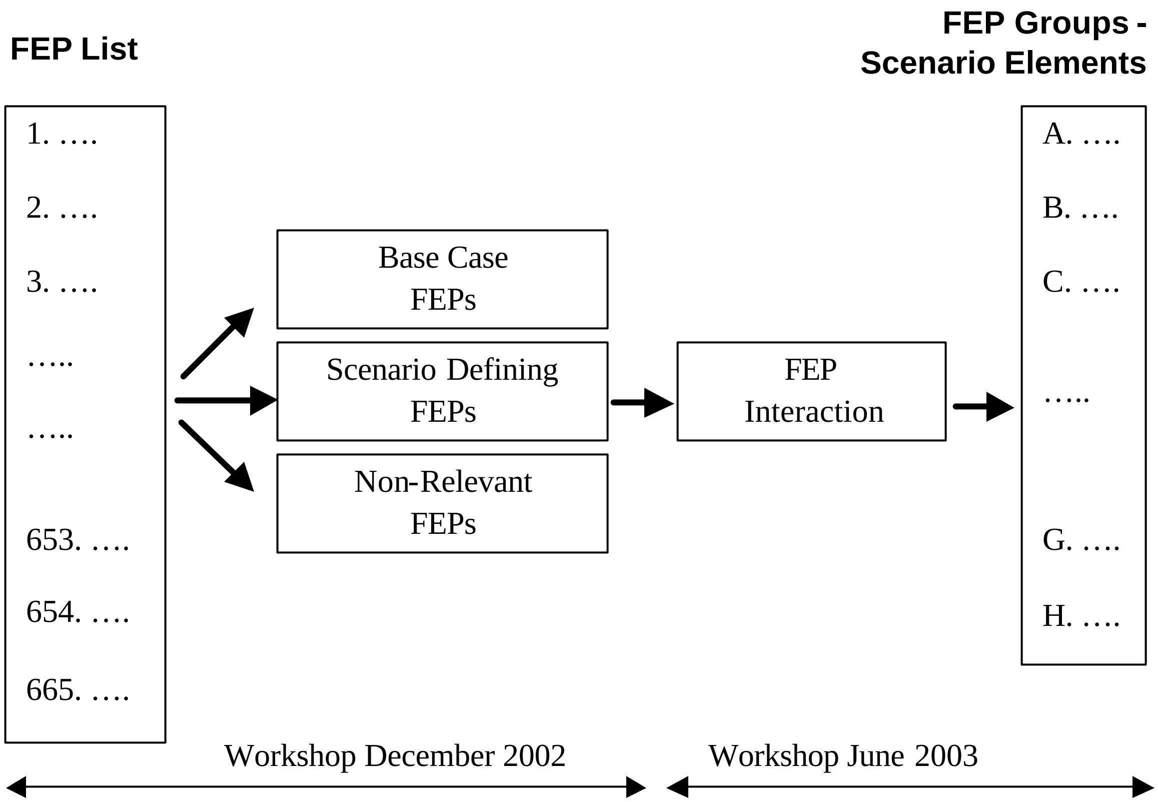


Figure 15 Workflow topics of December 2002 and June 2003 (day 1).

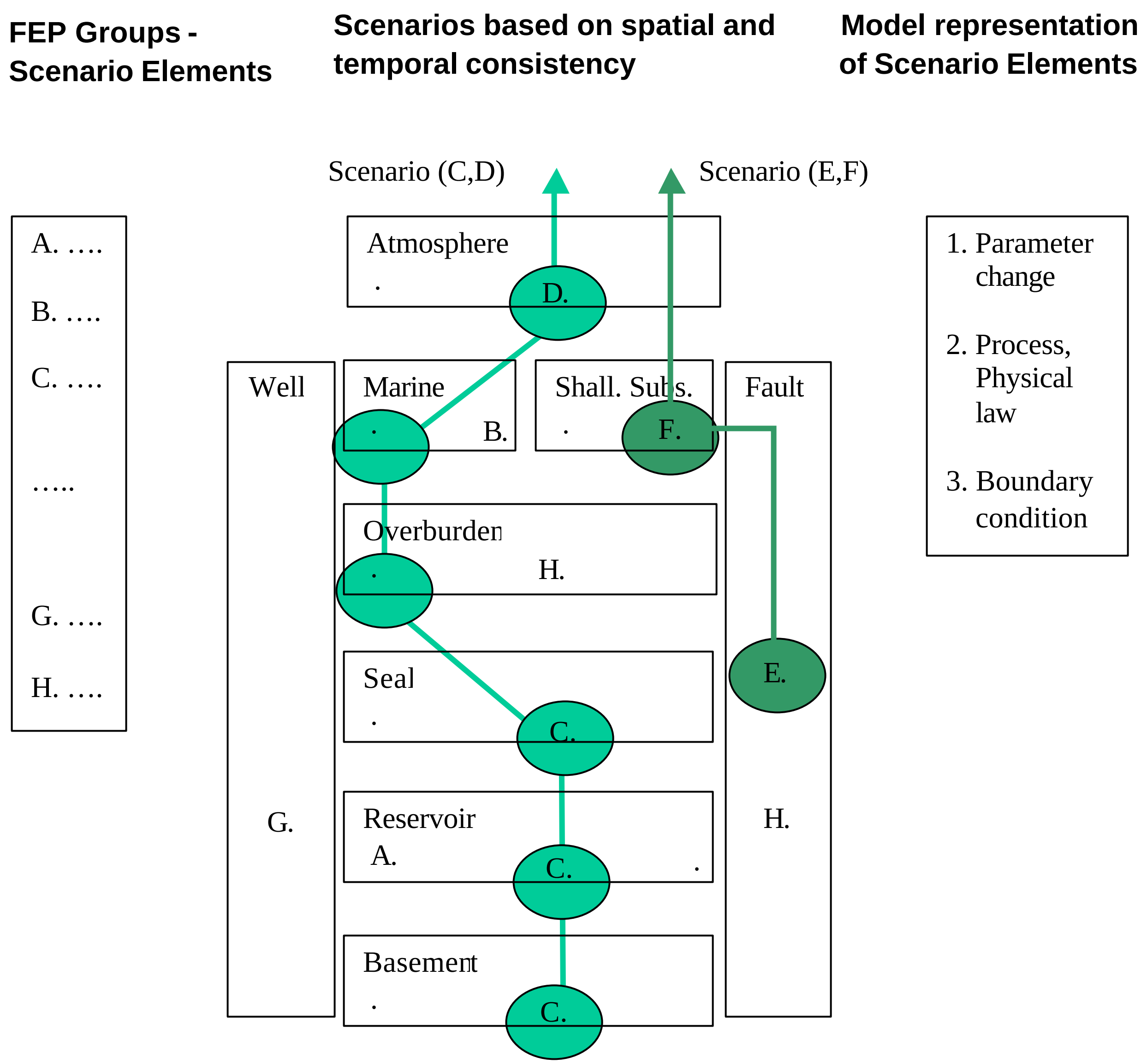


Figure 16 Overview of workshop topics June 2003 (day 2)

Day 2

The development of scenarios will be the main topic of day 2. In the morning the results of day 1 will be presented by the group chairmen. During the group sessions, the scenario elements that have been assigned to the model compartments will be analyzed in more detail (Fig. 16). Interaction between scenario elements will be evaluated. Risk scenarios will be constructed with the aid of the scenario elements based on spatial and temporal consistency. The model representation of the risk scenarios and scenario groups will be discussed. At the end of the day, the applicability of the FEP methodology and tools will be evaluated.

A post-workshop document will be sent to all participants. It will summarize the hands-on experience with regard to the FEP methodology, the FEP analysis tools, possible bottlenecks and recommendations.

Enclosures:
Assessment basis
List of scenario defining FEPs

2.1.2 HSE Probabilistic Risk Assessment Methodology

Report Title

CO_2 Capture Project - An Integrated, Collaborative Technology Development Project for Next Generation CO_2 Separation, Capture and Geologic Sequestration

HSE Probabilistic Risk Assessment Methodology

Report Reference

2.1.2

Type of Report:	Semi-Annual Report
Reporting Period Start Date:	February 2003
Reporting Period End Date:	July 2003
Principal Author(s):	Jenn-Tai Liang, Shaochang Wo (INEEL) and Larry Myer (LBNL)
Date Report was issued:	August 2003
DOE Award Number:	DE-FC26-01NT41145
Submitting Organization:	Idaho National Engineering and Environmental Laboratory
Address:	P.O. Box 1625 2525 North Fremont Ave. Idaho Falls, ID 83415

2.1.2.1 Abstract

A geomechanical study was performed to evaluate geomechanical factors that need to be taken into account in assessing the risk of CO_2 leakage in CO_2 sequestration in coal beds. The study revealed that geomechanical processes lead to risks of developing leakage paths for CO_2 at each step in the process of CO_2 sequestration in coal beds. Risk of leakage is higher for old wells converted to injectors. Risks of leakage is much higher for open cavity completions than for cased well completions. Coal properties and available technology should minimize the risk that hydrofractures, used as part of completion, will grow out of interval. The processes of depressurization during dewatering and methane production, followed by repressurization during CO_2 injection, lead to risks of leakage path formation by failure of the coal and slip on discontinuities in the coal and overburden. The most likely mechanism for leakage path formation is slip on pre-existing discontinuities that cut across the coal seam. The predictive quantitative modeling study consists of a simulation history match and forecast in an actual field case (Tiffany field), a sensitivity study of key coal reservoir properties, and a CO_2 seepage assessment from outcrops. This approach establishes a linkage between the first-hand knowledge of the actual field performance and a more realistic CO_2 seepage forecast. By matching the nitrogen breakthrough times and nitrogen cut in Tiffany field, simulation revealed that the elevated pressure by N_2 injection caused the coal fractures on the preferred permeability trends not only to expand but also to extend from injectors to producers. Even in the low-pressure regions near the producers, the permeabilities were higher than expected. The model also predicted early inert gas (N_2 plus CO_2) breakthrough and high inert gas cut during future gas injections. The high volume of inert gas produced could overwhelm the reprocessing capability resulting in early termination of the project. Under preferable scenarios, if CO_2 injection wells are placed below and at least 2 miles away from the water table, no significant change in methane seepage from outcrop has been predicted by simulations with various CO_2 injection schemes. However, under certain conditions, simulation predicted that a large CO_2 and methane breakthrough could happen if the CO_2 injection wells are too close, within 2 miles, to the outcrop. Consequently, any CO_2 injection within a distance of 3 miles from outcrop should be considered with high risk.

2.1.2.2 Table of Contents

2.1.2.3 Lists of Graphical Materials

2.1.2.3.1 List of Figures

2.1.2.3.1 List of Tables

2.1.2.4 Introduction

There is a growing consensus in the international community that CO_2 emissions from burning fossil fuels play an important role in global climate change. Despite the recent controversy of who should bear the burden in reducing the CO_2 emissions, it appears inevitable that deep cuts in CO_2 emission will be required in the near future. Recent efforts in reducing the carbon content in fuels and improving the energy efficiency can certainly help in reducing the amount of CO_2 released into the atmosphere. However, large-scale carbon sequestration will definitely be required to achieve the targeted atmospheric CO_2 level of 550 ppm by 2025. The first large-scale opportunities for carbon dioxide sequestration are likely to be associated with storage in geologic formations. These geologic formations include oil and natural gas reservoirs, saline aquifers, and coal beds. In some instances, the recovery of a saleable commodity will offset the cost of sequestration. Naturally, these projects will be favored over non-income generating projects. Included within this category are CO_2 injection for enhanced oil recovery, pressure maintenance of oil or gas reservoirs, and enhanced methane production from coal seams. Of the sequestration options available, geologic sequestration of CO_2 in coal formations is considered one of the methods with the greatest short-term potential. Coal beds typically contain a large amount of methane-rich gas that is adsorbed onto the surface of the coal. Tests have shown that CO_2 is roughly twice as adsorbing on coal as methane, giving it the potential to efficiently displace methane and remain sequestered in the coal bed.

The goal of this project is to provide a methodology acceptable to regulators and the public alike by which to conduct a meaningful probability based risk assessment of CO_2 injection and storage in coal beds. Consequently, the work will develop the necessary knowledge, tools, and strategies for risk evaluation, risk mitigation, and monitoring and verification. The work is conducted within the context of an actual field demonstration of the technology employing field data from BP's Tiffany project in the San Juan Basin, Colorado. To date, BP's Tiffany project is the only commercial scale enhanced coal bed methane recovery by gas injection in the US.

2.1.2.4.1 Project Workscope

The work scope of this project includes three major task areas:

<u>2.1.2.4.1.1 Task 1. Data acquisition/knowledge gaps.</u>

A systems engineering study using a master-logic diagram will be performed to identify possible event initiators. Geomechanical studies will be performed to evaluate the effect of geomechanical properties and processes on the movement of CO_2 in a coal seam and the potential of leakage of CO_2 from the coal seam.

<u>2.1.2.4.1.2 Task 2. Predictive quantitative modeling.</u>
Predictive reservoir models for the Tiffany field will be built using BP's proprietary GCOMP simulator to estimate the storage capacity, in-situ *concentration, transport velocity, contacted volume, and the timeframe for filling, monitoring, and storage. In the risk assessment phase the above model will be used to predict CO_2 transport during and after CO_2 injection, inside and outside the immediate boundary of the field.*

<u>2.1.2.4.1.3 Task 3. Consequence analysis and risk characterization.</u>
The physical consequences of the risk initiating events will be quantified. Both normal operation risk and accident risk will be included. The above predictive model(s) will be used to conduct probabilistic simulations for each risk scenario identified.

2.1.2.4.2 Project Milestones

Figure 1 is a Gannt Diagram that shows the project milestones. The project is current on schedule and on budget.

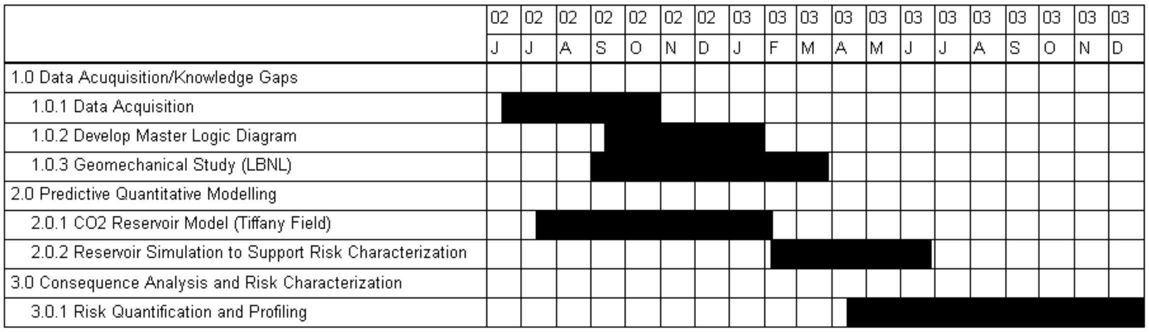


Figure 1. Project Gannt Diagram

2.1.2.5 Executive Summary

This semi-annual report describes work completed during the period between February 2003 and July 2003 of the project "Methodology for Conducting Probabilistic Risk Assessment of CO_2 Storage in Coal Beds." The objective of this project is to provide a methodology acceptable to regulators and the public alike by which to conduct a meaningful probability-based risk assessment of CO_2 injection and storage in coal beds. The work is conducted within the context of an actual field demonstration of the technology employing field data from BP's Tiffany project in the San Juan Basin, Colorado.

2.1.2.5.1 Geomechanical Study (Task 1.0.3)
In order to evaluate the geomechanical issues in CO_2 sequestration in coal beds, it is necessary to review each step in the process of development of such a project and evaluate its geomechanical impact. A coal bed methane production/CO_2 sequestration project will be developed in four steps:

- Drilling and completion of wells
- Formation dewatering and methane production
- CO_2 injection with accompanying methane production
- Possible CO_2 injection for sequestration only

2.1.2.5.1.1 Drilling and Completion Issues
Wellbore stability is a geomechanical problem that can be encountered during drilling of the well. Weak shale layers, weak coal layers, overpressure, and faults zones are common causes. Rock failure and displacements associated with wellbore instability generate potential leakage paths in the vicinity of the well. The risk of leakage will be minimized by cementing the casing. Risks of leakage are much higher for open cavity completions than for cased well completions. Careful selection of fracturing technology for well completion that account for the specific coal properties should minimize the risk that hydrofractures grow out of interval. Techniques to monitor fracture height need further development.

2.1.2.5.1.2 Production and Pressurization Risks
The processes of depressurization during dewatering and methane production, followed by repressurization during CO_2 injection, lead to risks of leakage path formation by failure of the coal and slip on discontinuities in the coal and overburden. The most likely mechanism for leakage path formation is slip on pre-existing discontinuities which cut across the coal seam. Relationships between the amount of slip and the increase in flow (if any) along a discontinuity need to be developed.

2.1.2.5.2 Predictive Quantitative Modeling (Task 2)
Quantitative risk assessment of CO_2 sequestration in coal formations is fundamentally linked to predictive reservoir models. These models are necessary to estimate storage capacity, *in-situ* concentration, transport velocity, contacted volume, and the timeframe for filling, monitoring, and storage. The actual CO_2 sequestration capacity of coal is largely dictated by how effectively injected gases contact and interact with the reservoir over the active project lifetime. The economic limit for methane recovery and CO_2 storage is usually dictated by CO_2 breakthrough, poor injectivity or a variety of other factors that make further operation economically prohibitive. In this study, the focus of quantitative modeling was placed on an actual field case (Tiffany field), the sensitivity study of key coal reservoir properties, and CO_2 seepage from outcrops. This approach establishes a linkage between the first-hand knowledge of the actual field performance and a more realistic CO_2 seepage forecast. For comparison and validation purpose, two reservoir simulators were used, the BP-Amoco GCOMP and the COMET2, developed by Advanced Resources International.

2.1.2.5.2.1 CO_2 Sequestration Modeling in Coal Formation – Tiffany Field
A mechanistic field model was developed to match the field performance of a 5-spot pattern in the northern part of the Tiffany Field where BP-Amoco is conducting nitrogen injection to enhance methane

recovery and plans to perform a micro-pilot CO_2 injection test. By matching the nitrogen breakthrough times and nitrogen cut, simulation revealed that the elevated pressure by N_2 injection caused the coal fractures on the preferred permeability trends not only to expand but also to extend from injectors to producers. Even in the low-pressure regions near the producers, the permeabilities were higher than expected. The model suggests that the future gas injection and CO_2 sequestration may be restricted to only one third of the total available pay. The model also predicted early inert gas (N_2 plus CO_2) breakthrough and high inert gas cut during future gas injections. The high volume of inert gas produced could overwhelm the reprocessing capability resulting in early termination of the project.

2.1.2.5.2.2 Effects of Coal Formation Properties

The findings from a sensitivity simulation study of key coal reservoir properties include: 1) Laboratory measured isotherms on dry coals should be rescaled by matching field history performance. Without rescaling, incorrect estimates of initial methane content calculation, CO_2 sequestration capacity in coal, and CO_2 or N_2 injection performance could result. 2) During the primary production, the gas to water production ratio is very sensitive to cleat porosity because the cleat porosity is usually very small and initially filled with water. 3) The permeability aspect ratio of face cleat permeability to butt cleat permeability could have a significant effect on gas and water production rates as demonstrated in history matching the five production wells in the Tiffany pilot area. 4) The early N_2 breakthrough and high N_2 cut observed in the Tiffany field suggest that the elevated pressure during gas injection caused the coal fractures on the preferred permeability trends not only to expand but also to extend from injectors to producers. Consequently, the injected inert gas (CO_2 or N_2) may only contact a small portion of the entire pay volume. A dual model with one injection well and one production well on a 160-acre well spacing was used to simulate the effect of coal net pay thickness thereby the coal volume on the inert gas production cut. In comparison with the actual field performance, it suggests that only about one tenth to one fifth of the total pay interval may be contacted by injected inert gas (CO_2 or N_2).

2.1.2.5.2.3 Assessment of CO_2 Seepage from Outcrop

A representative seepage model was developed for the Fruitland coal in Colorado portion of the San Juan basin. The model is a two-layer, 1.25 mile by 12 mile strip with a down dip of 2.92 degree from the up outcrop to the bottom of the basin. The model consists of two seepage wells to represent the 1.25 mile outcrop and three water recharge wells placed just below the water table to represent the ground water recharge. Under preferable scenarios, if CO_2 injection wells are placed below and at least 2 miles away from the water table, no significant change in methane seepage from outcrop has been predicted by simulations with various CO_2 injection schemes. To simulate the worst case scenarios, CO_2 injection wells have been placed above the water table. The results show that a large CO_2 and methane breakthrough could happen if the CO_2 injection wells are too close, within 2 miles, to the outcrop. Consequently, any CO_2 injection within a distance of 3 miles from outcrop should be considered with high risk.

2.1.2.6 Geomechanical Study

The purpose of this report is to summarize and evaluate geomechanical factors which should be taken into account in assessing the risk of leakage of CO_2 from coal bed sequestration projects. The various steps in developing such a project will generate stresses and displacements in the coal seam and the adjacent overburden. The question is whether these stresses and displacements will generate new leakage pathways by failure of the rock or slip on pre-existing discontinuities such as fractures and faults.

To evaluate the geomechanical issues in CO_2 sequestration in coal beds, it is necessary to review each step in the process of development of such a project and evaluate its geomechanical impact. A coal bed methane production/CO_2 sequestration project will be developed in four steps:

- Drilling and completion of wells
- Formation dewatering and methane production
- CO_2 injection with accompanying methane production
- Possible CO_2 injection for sequestration only

The approach taken in this study was to review each step: Identify the geomechanical processes associated with it, and assess the risks that leakage would result from these processes.

2.1.2.6.1 Drilling and Completion Risks

2.1.2.6.1.1 Drilling Issues

Wellbore stability is a geomechanical problem which can be encountered during drilling of the well. Weak shale layers, weak coal layers, overpressure, and faults zones are common causes. Rock failure and displacements associated with wellbore instability generate potential leakage paths in the vicinity of the well. The risk of leakage will be minimized by cementing the casing. It is conventional practice to place cement behind production casing, and the depth over which it is placed is subject to state regulations. Title 19 chapter 15 of the New Mexico Admin istrative Code states "cement shall be placed throughout all oil-and gas-bearing zones and shall extend upward a minimum of 500 feet above the uppermost perforation or, in the case of open-hole completion 500 feet above the production casing shoe". Alabama's regulations specific to coalbed methane operations have been used by other states as a model. Section 400-3 of the Rules and Regulations of the State Oil and Gas Board of Alabama states that the casing shall be cemented for 200 feet above the top of the uppermost coalbed which is to be completed, or for 200 feet above the production casing shoe in open hole completions. The production interval in cased hole completions need not be cemented.

When a coalbed methane project is converted to CO_2 sequestration, CO_2 will be injected under pressure. Wells used for injection in oil and gas formations are subject to additional regulations requiring periodic testing for leakage in the cased section. The type of testing which is required is set by individual states. In New Mexico, these tests can include the use of tracers to test for leakage in the annulus.

Injection of CO_2 also increases the risk of leakage in the annulus between casing and formation due to chemical dissolution of the cement. Experience in enhanced oil recovery has lead to development of additives for cement used for CO_2 injectors. This experience should be applicable to coal bed methane CO_2 projects.

If old production wells or idle wells are used for CO_2 injection there is a risk that leakage paths may be present in the annular space between the casing and the rock due to deteriorated or missing cement. Casing bond logs and tracer tests can be used to evaluate the integrity of the cement in the annulus or the contact between casing and formation. If it is found that leaks may occur, cement can be injection (squeezed) into the annulus. However, the process of seal formation in the annulus by cement squeeze behind casing is expensive and often only partially successful.

Because of the importance of the casing cement in minimizing the risk of CO_2 leakage, additional work should be directed toward development of recommendations for best practices. In particular, criteria for setting the height of the cement behind casing needs further study. Because of the substantial industry experience in water flooding and CO_2 enhanced oil recovery, a case history study of the performance of production casing cement would provide valuable data for a best practices study.

2.1.2.6.1.2 Conventional Completions

A conventional completion for a coal bed methane project involves perforating or slotting the casing in the coal seam (Figure 2). Since the permeability of coal matrix is low, hydrofracturing is used to enhance permeability during dewatering and primary production. If the project is converted to CO_2 enhanced recovery and sequestration, pre-existing hydrofractures will enhance the injectivity of the CO_2. However, the risk of CO_2 leakage is also increased if hydrofractures extend into the overburden. Growth into the overburden can happen when the hydrofracture is initially created. Since CO_2 is injected under pressure, there is risk that growth into the overburden could also occur during the enhanced recovery and sequestration phases of the project.

The potential for vertical extension of a hydraulic fracture is dependent upon several factors (Ben-Naceur 1989):

- In-situ stress state
  Higher horizontal stress in surrounding layers will impede vertical fracture growth, while lower horizontal stress tends to accelerate it. Higher pore pressure will enhance fracture growth. On average, horizontal stress increases with depth due to gravity but it is known that lithology can affect in-situ stress values. Pore pressures can also depart significantly from a “normal” hydrostatic gradient depending on numerous natural hydrostratigraphic conditions as well as previous production and injection activities in the field.

- Elastic moduli
  Vertical growth is impeded if the adjacent layer is stiffer than the coal seam. This is most likely to be the case if limestone or sandstone are the bounding strata. Siltstones and shale can vary widely in properties, but many are also stiffer than coals.

- Toughness
  Higher fracture toughness will impede fracture growth. For large fractures, tensile strength is not a major factor (Ben-Naceur 1989). The fracture toughness of coal is not well known. Atkinson and Meredith (1987) compiled results of tests on four different coals. For Latrobe Valley Brown and Pittsburgh coal, values of “stress intensity resistance” ranged from 0.006 $MPam^{½}$ to 0.063 $MPam^{½}$. However, for Queensland semi-anthracite and New South Wales black coal, values ranged from 0.13 $MPam^{½}$ to 0.44 $MPam^{½}$. For comparison, values for sandstone, shale and limestone ranged from about 0.4 $MPam^{½}$ to 1.7 $MPam^{½}$, with values for limestone generally being higher. This data indicates that some coals will have significantly lower fracture toughness than typical bounding formations, and, therefore, low risk of fracture growth out of interval.

- Leakoff
  High fluid loss in the bounding layer will retard growth of a fracture propagating into it.

- Fluid flow
  Vertical fracture propagation will also be affected by the vertical component of fluid flow, which is affected by fracture opening and fluid properties. Non-Newtonian fracture fluids can have significant impacts on fracture growth. Carbon dioxide is normally modeled on a Newtonian fluid. However, it will generally be in the non-wetting phase. The effects of

the fluid properties of CO_2 (particularly the non-wetting characteristics) on fracture propagation are a topic for further research.

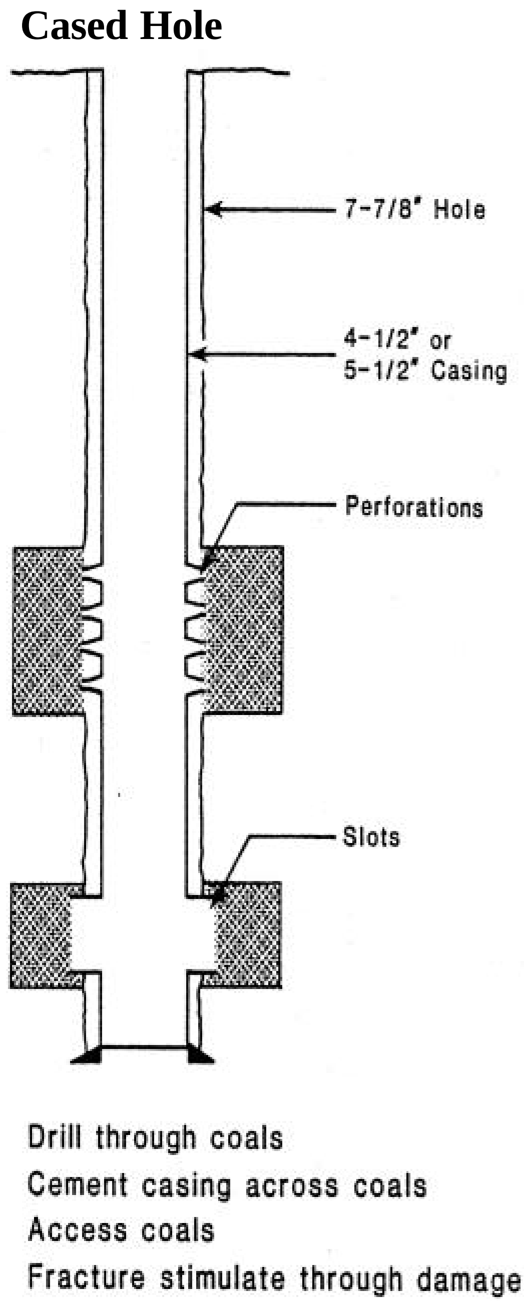


Figure 2. Schematic diagram of core hole completion for coal bed methane well. (Murray 1993)

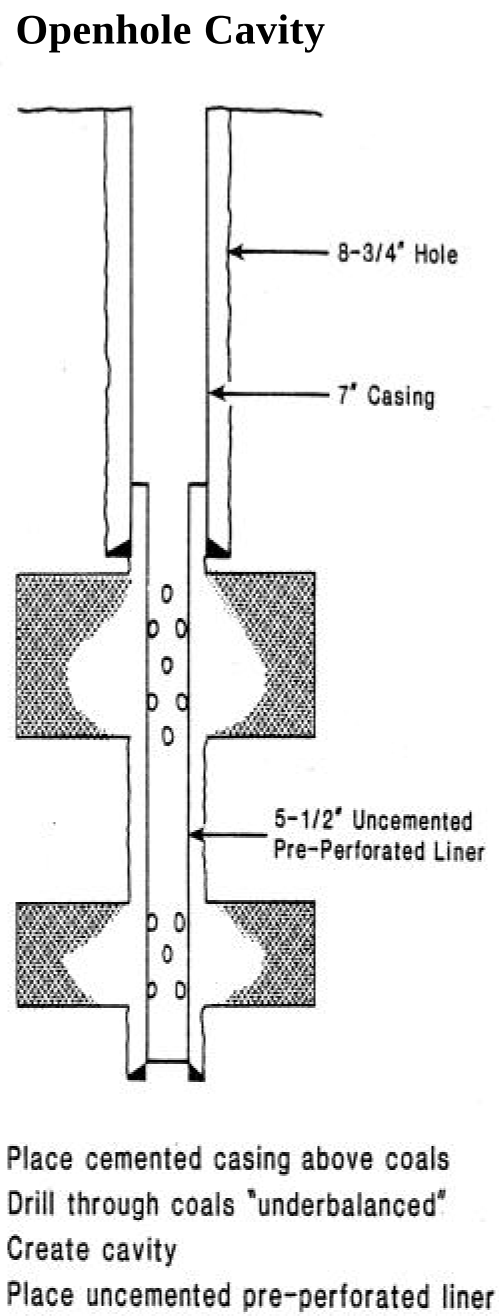


Figure 3. Schematic diagram of cavity completion for coal bed methane well. (Murray 1993)

Linear elastic fracture mechanics models have been developed to predict vertical fracture growth (see Ahmed 1989 for summary). Ahmed et al (1985) developed expressions specifically for design in multiple zones. The approach is to first calculate the stress intensity factors for the top and bottom of the fracture. The stress intensity factor is a function of the height of the fracture the in-situ horizontal effective stress, and the fluid pressure in the fracture. Fracture growth is predicted when the stress intensity factor exceeds a critical value given by the fracture toughness of the rock.

Risk of leakage will be reduced if the vertical extent of hydrofractures can be monitored. In cased wells measurement of fracture height, or detection of vertical propagation into bounding formations, is a challenging undertaking. Ahmed 1989, and Anderson et al 1986, describes the use of radioactive tracers in conjunction with gamma ray logging. However, this technique only provides information in the near wellbore region.

In principle, seismic methods could be used to monitor the extension of a hydrofracture. Passive seismic techniques use seismic “events” generated by the fracturing process to locate the fracture. The fracture can also be imaged by a number of active seismic techniques. Though field experiments have been conducted, there is as yet no generally accepted seismic technique for determining fracture height. Nolte and Economides (1989) describe a method for interpreting the downhole pressure decline during pumping to determine if a fracture has propagated into a bounding layer. Pressure analyses are complicated by a number of factors which influence the pressure response.

2.1.2.6.1.3 Open Cavity Completions

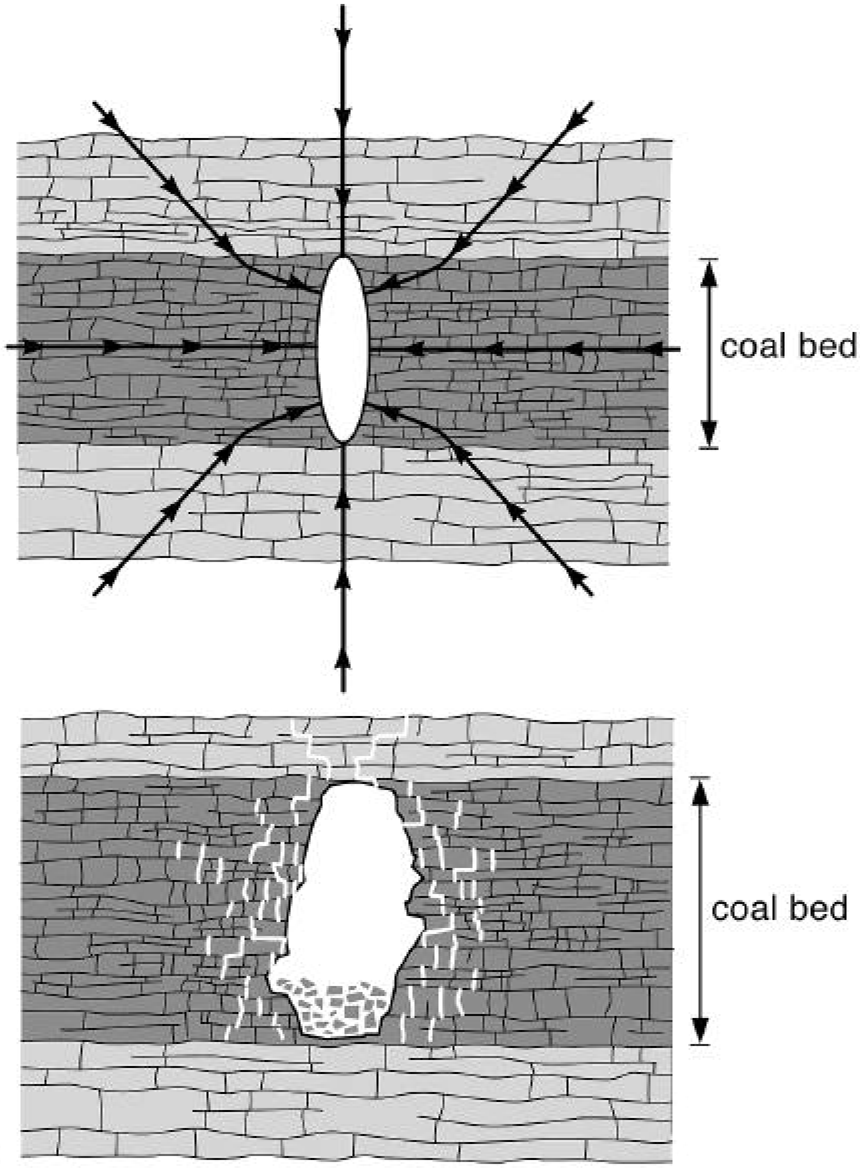
A second type of completion for coal bed methane projects is the open hole cavity method (Figure 3). This technique was developed in the San Juan basin and is advantageous in areas where reservoir pressures are higher than normal. In such areas, casing is set above the coal seam and a cavity is generated by one of two methods (Bland 1992). The first method is to drill through the coal seam underbalanced with water, air or foam. The excess formation pressure causes the coal to collapse into the wellbore. The coal is removed by displacing with drilling fluid and a perforated screen is set.

The second method uses pressure surges to collapse the coal. The well is shut in to build up pressure and then is abruptly released. Collapsed coal is then removed. This process can be repeated several times until the coal no longer collapses. Bland (1992) reported that the effect could extend as much as 100 m into the coal seam.

Creation of a cavity can potentially cause failure and displacements in the overlying strata which provide pathways for CO_2, and increase the risk of leakage. Factors which influence the amount of disturbance in the overburden include the size and shape of the cavity, surge pressures, depth and in-situ stress, layer thickness, rock strength and degree of natural fracturing in the overburden.

The process of pressure surging sets up high pore pressure gradients in the rock and corresponding flow lines as schematically illustrated in Figure 4a. Underbalanced drilling has the same affect though the pore pressure gradients would be lower. These pressure gradients cause fractures, joints, and cleats oriented perpendicular to the flow lines to open, leading to sloughing of the coal into the opening. The pressure gradients are also present in the overburden, so there is risk that this rock will also collapse into the cavity. The risk is highest for weak, thinly bedded, highly fractured shale. The risk is least for massively bedded sandstone and limestone.

The risk of overburden collapsing into the cavity increases as the cavity grows in width. As shown in Figure 4b, removal of coal results in an unsupported span of layered overburden. As the span increases, so does the likelihood of finding fractures which define blocks. These blocks can be moved or removed by repeated surging. Since the interfaces between rock layers are weak, repeated surging would also tend to cause separation between layers producing more fluid pathways.



a)
b)

Figure 4. Schematic illustration of rock mass behavior associated with cavity completions in coal beds

a) Flow lines for water movement during surging
b) b) Growth of cavity and fracturing in the coal and overburden

Creation of a cavity also results in a redistribution of the in-situ stresses. This redistribution is very dependent upon the shape of the cavity as well as the relative magnitude of the vertical and horizontal far field stresses. The shape of the cavity formed by surging can be approximated by an ellipsoid with major axis equal to the thickness of the seam. The stress distribution around an elliptical (2-D) cavity with major axis oriented parallel to the vertical far field stress is shown in Figure 5. It is seen that near the opening, in a direction along the minor axis the horizontal stress is less than the far field stress. Thus the stress redistribution would be acting to further open fractures already opened by pressure surging. Similarly, along the major axis the vertical stress is less than the far field, increasing the risk that pressure surges would cause bedding plane partings.

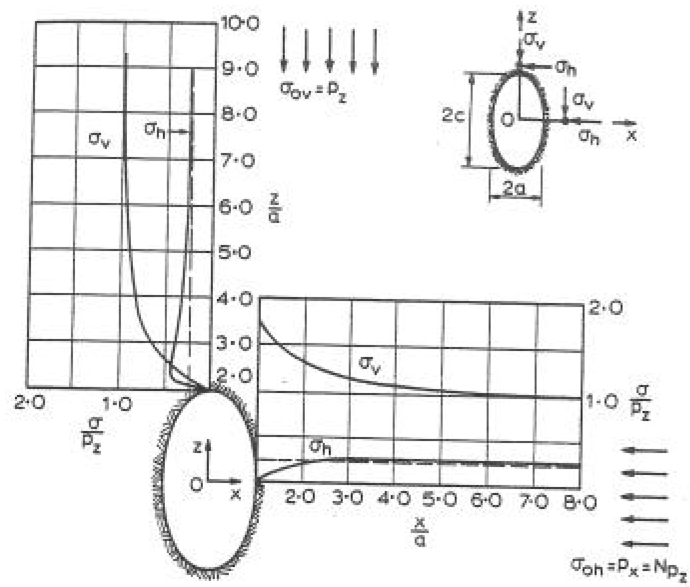


Figure 5. Stresses around an elliptical cavity (a/c=½) in homogeneous stress fields (N=0.25) (Poulos and Davis, 1974, Terzaghi and Richart, 1952)

2.1.2.6.2 Production and repressurization risks

The pore pressure reductions which occur during dewatering and methane production and pore pressure increase which occur during CO_2 injection, cause displacements in the reservoir and surrounding rock. A conservative assumption (to be discussed further) is that leakage will result if the rock fails or if slip occurs on pre-existing faults or discontinuities.

2.1.2.6.2.1 Failure and Slip in a Coal Seam

A convenient way of assessing the potential for failure or slip is the Mohr diagram (Figure 6). A simple two-dimensional linear Mohr-Coulomb failure criterion is shown for illustration. The effective principal stress defined as total stress minus pore pressure is plotted on the horizontal axis and referred to as "normal stress". It is commonly assumed that an increase in pore pressure in the reservoir has an equal effect on both components of principal stress, causing the Mohr circle to shift to the left, closer to failure, that is, from I? II in Figure 6. This assumption has been employed in previous assessments of the potential for fault slip due to reservoir pressurization by CO_2 injection (Gibson-Poole et al, 2002). If pore pressures are reduced, it follows from this model that both components of effective stress would be increased by the same amount, moving the Mohr circle away from failure.

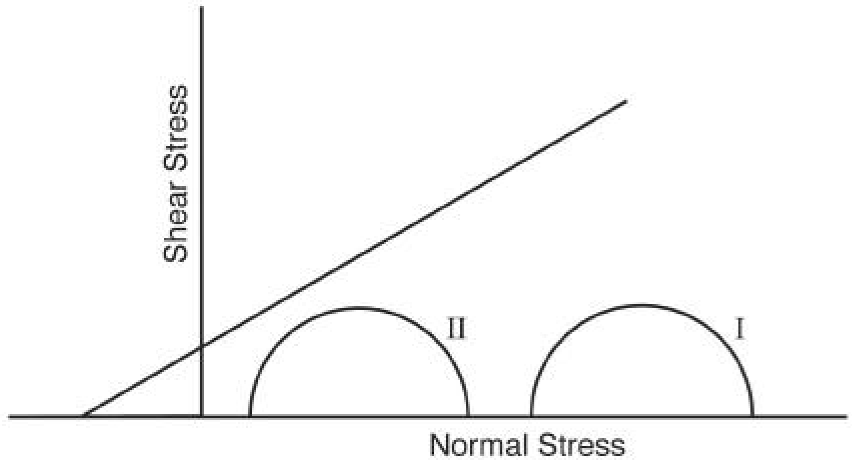


Figure 6. Mohr circles for initial (I) and final (II) stress state when it is assumed that a pore pressure increase affects both principal stresses equally.

Observations in a number of petroleum reservoirs (Addis, 1997 a, b) have shown that the reduction in pore pressure due to production causes a smaller change in horizontal stress than in vertical stress. The effect on the potential for failure is shown in Figure 7. Since pore pressures are decreasing, the Mohr circle moves to the right. However, since the change in horizontal effective stress is less than in the vertical effective stress, the circle actually gets closer to failure that is from I? III in Figure 7. Teufel, et al, 1991, showed that these effects were large enough to cause failure of the high porosity chalk in the North Sea Ekofisk reservoir. Streit and Hillis, 2002, further analyzed the effects on fault slip.

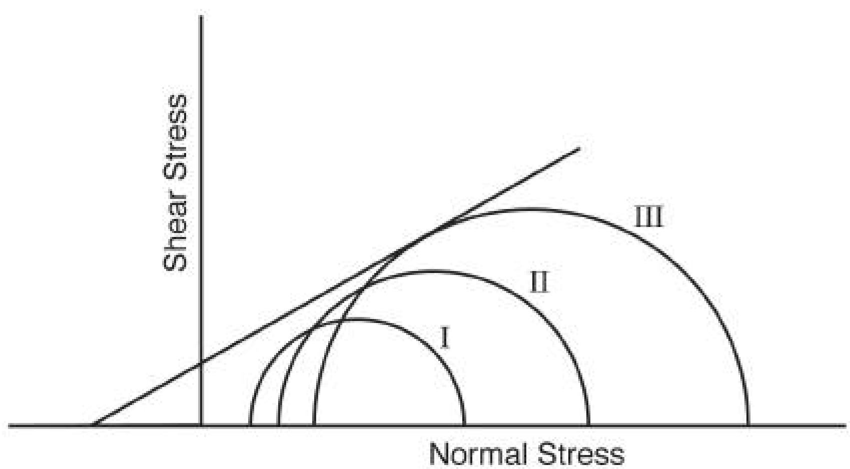


Figure 7. Mohr circles for initial (I), intermediate (II), and final (III) stress states for pore pressure reduction assuming that horizontal stresses are less affected than vertical stresses. Failure or slip occurs at III.

These relative changes in horizontal and vertical effective stresses are the result of the effects of far field (in-situ) boundary conditions and poroelastic properties of the rock. Figure 8 shows that the rate of change in horizontal stress with pore pressure, i.e. $\Delta\sigma_h/\Delta P$ where σ_h is horizontal stress and P is pore pressure, decreases as Poisson's Ratio of the reservoir rock increases. Touloukian and Ho, 1981, report measured values of Poisson's Ratio for coal of 0.2 to 0.4.

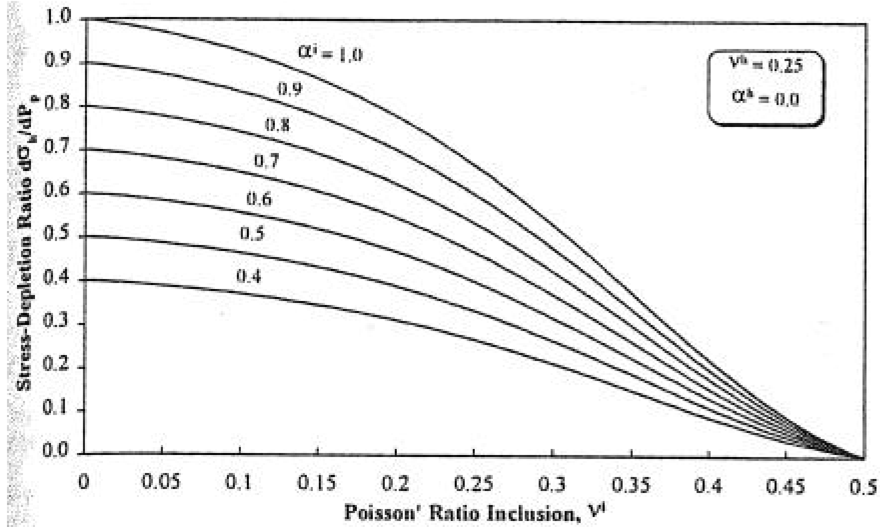


Figure 8. Effect of Poisson's ratio of the reservoir rock on rate of change in horizontal stress with pore pressure for a disc-shaped reservoir modeled as an inclusion (i) in a host (h) rock. And various Biot coefficient (Addis et al, 1998).

The risk of failure or slip in the coal will depend on depth, in-situ stress state, pressure drawdown, and coal strength and poroelastic properties. Conditions which result in large principal stress differences increase the risk of failure and slip. Tectonic activity will result in increased differential far field stresses. Large pore pressure drawdown will increase differential stress. Risk of failure increases for low strength coal. In-situ stresses increase with depth, but the strength of rock increases with level of confinement. The risk of failure may or may not increase with depth depending on the amount of pore pressure drawdown and the magnitude of differences between components of in-situ stress. The risk of slip on pre-existing discontinuities is increased for low cohesion and low frictional sliding resistance.

Injection of CO_2 for enhanced methane production and sequestration will increase pore pressures in the coal seam. In a poroelastic system, effective stress changes due to pore pressure drawdown are simply reversed by pore pressure increase due to injection. Thus, a Mohr circle which had moved closer to failure under drawdown would move farther from failure during injection until the original, pre-development pore pressures are obtained. Failure, however, is an inelastic process and, in general, results in a complex redistribution of stress in the system.

If pore pressures from CO_2 injection exceed pre-development levels, then there is a risk that slip will occur even though it had not occurred under drawdown conditions. This is conceptually illustrated in Figure 9, where the Mohr circle for pre-development stress state is labeled I. Dewatering and methane production moves the Mohr circle to the right (state II) under conditions in which the change in horizontal effective stress is less than the change in vertical effective stress. The maximum stress difference is not sufficient to cause failure or slip. Upon repressurization, assuming no inelastic effects, the Mohr circle returns to state I. If pressurization continues so that pore pressures rise above pre-development levels the Mohr circle moves to the left, resulting in the condition for failure or slip as indicated by state III in the figure. It has been assumed in this construction that the vertical effective stress changes more rapidly than the horizontal effective stress during pore pressure increase.

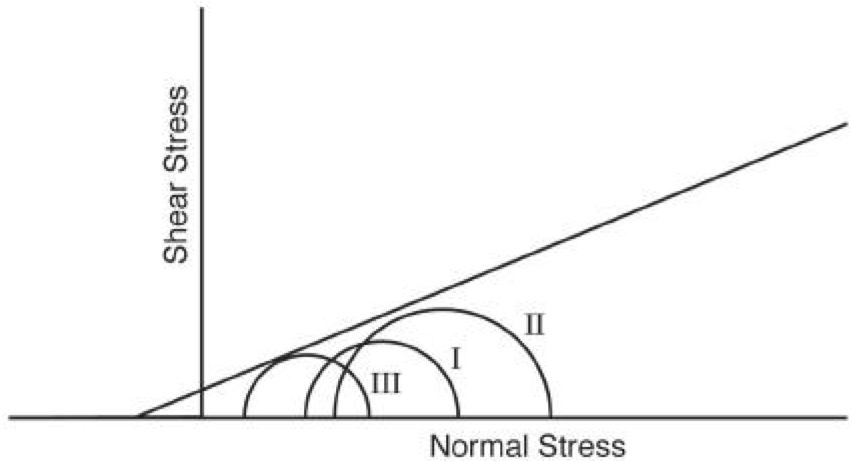


Figure 9. Mohr circles for initial (I), intermediate (II) and final (III) stress state when pore pressure first decreases (II) and then increases (III) with respect to initial conditions. Failure or slip occurs at III.

The approach outlined above can be used to make a preliminary assessment of the potential for slip on pre-existing discontinuities in the coal in the San Juan basin. Values of parameters used in the analysis are summarized in Table 1. A mean depth of 3,200 feet and an initial reservoir pressure of 1,500 psi before dewatering and methane production are assumed. The reservoir pressure is consistent with a normal hydrostatic gradient and observations in some areas of the San Juan basin. It is assumed that the maximum principal stress is vertical (S_V) and the density gradient is one psi per foot of depth. For purpose of this calculation the in-situ stress, S_{hmin}/S_V, where S_{hmin} is the minimum horizontal stress, is assumed to be 0.7. The condition for slip on the discontinuity is given by a linear Mohr-Coulomb criteria with the conservative assumption the cohesion is zero. A coefficient of friction, μ, of 0.6 is assumed. This value is frequently assumed in analyses of slip on faults in petroleum reservoirs (Gibson-Poole, et al, 2002, Peska and Zobach, 1995). It is also consistent with laboratory measurements of the strength of coal under confining pressures of several thousand psi (Murrell 1958).

Table 2. Slip Analysis Parameter

Parameter	Value
Mean reservoir depth	3,200 feet
Initial reservoir pressure	1,500 psi
Post drawdown reservoir pressure	500 psi
Reservoir pressure after CO_2 injection	2,000 psi
Poisson's ratio for coal	0.3, 0.4
Coefficient of friction for slip	0.6
In-situ stress ratio (S_{hmin}/S_V)	0.7

The Mohr circle labeled by I in Figure 10 represents the initial stress conditions. It is assumed that pore pressures have equilibrated over a large area over time, so the initial major and minor principal effective stresses, σ_1 and σ_3, are given by subtracting 1500 psi from both S_V and S_{hmin}. It is then assumed that reservoir pressures are drawn down to 500 psi and there is a poroelastic effect in a finite-sized reservoir. From Figure 8, if the Poisson's ratio of the coal is 0.3, then $\Delta S_{hmin} = -0.53\Delta P$ (where P is reservoir pressure and – refers to a decrease in P) and the Mohr circle moves to position labeled II. As seen in the figure, there is no slip. For a Poisson's ratio of 0.4, $\Delta S_{hmin} = -0.23\Delta P$ and the Mohr circle is given by II' which is a more stable condition than that attained for Poisson's ratio of 0.3

Finally, it is assumed that CO_2 injection increases reservoir pressure to 2,000 psi. Taking account of poroelastic effects and assuming a Poisson's ratio of 0.3 for the coal, the Mohr circle moves from II to III. For this case, there is still no slip on discontinuities. However, for Poisson's ratio of 0.4, $\Delta S_{hmin}=0.23\ \Delta P$, and the Mohr circle moves from II' to III'; intersecting the criterion for slip. During repressurization more stable conditions are attained if the Poisson's ratio of the reservoir material is low.

The dip of discontinuities upon which slip would occur can be determined from the intersection of the Mohr circle with the failure criteria. The equations for the two values of β corresponding to the points of intersection are (Jaeger and Cook 1971)

$$2\beta_1=\pi+\varphi-\sin^{-1}[(\sigma_m/\tau_m)\sin\varphi]$$

and $$2\beta_2=\varphi+\sin^{-1}[(\sigma_m/\tau_m)\sin\varphi]$$

where $$\varphi=\tan^{-1}\mu$$

$$\sigma_m=½(\sigma_1+\sigma_3)$$

$$\tau_m=½(\sigma_1-\sigma_3)$$

For conditions represented by the circle III' in Figure 10, slip would occur on discontinuities with dips between 50° and 70°.

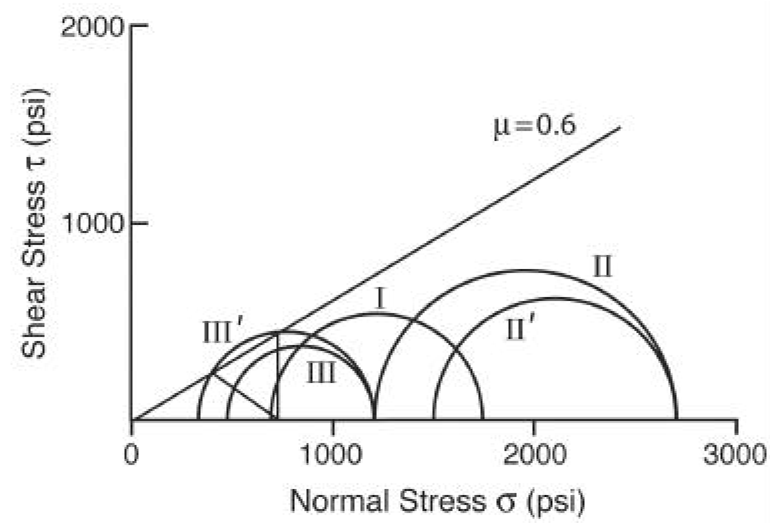


Figure 10. Mohr circles for slip on a discontinuity in a coal seam under conditions representative of the San Juan basin.

Results of these analyses are very sensitive to the in-situ stress state. The risk of slip is significantly reduced as $S_{hmin}/S_V \rightarrow 1$. If the stability analysis is repeated assuming $S_{hmin}/S_V=1$, a common assumption in reservoir simulation, then no slip would be predicted for any of the reservoir pressure conditions.

However, if $S_{hmin}/S_V=0.6$, slip is predicted even under the assumed initial reservoir pressure of 1,500 psi.

<u>2.1.2.6.2.2 Failure and Slip in the Overburden</u>

So far, the discussion has focused only on the risk of failure or slip within the coal seam. However, potential leakage paths require failure in slip in the bounding rock layers as well as in the coal seam. A possible, though least likely mechanism, is the propagation of a shear failure from the coal into the bounding rock. As discussed previously, fracture propagation into the bounding rock is impeded when the coal strength is less than the strength of the bounding rock.

Volumetric changes in the reservoir have an important influence on displacements in the overburden. During production, there is a volumetric decrease in the reservoir due to pore pressure reduction. The amount of volumetric decrease is a function of the compressibility of the reservoir rock and its thickness.

In coal there is an added component due to shrinkage from desorption of the methane. The volumetric decrease in the reservoir causes subsidence of the overburden. On the flanks of the reservoir, bending of the overburden layers results in shear stresses which can cause failure or slip on pre-existing discontinuities. If the pore pressure distribution, and hence, volumetric deformation, in the reservoir is not uniform, shear displacements in the overburden will be introduced at places other than the flanks.

Repressurization of the reservoir causes volumetric expansion and upward displacement, or heave, in the overburden. The effect on shear displacements is to reverse the sense of motion. Thus, shear displacement on a discontinuity can move in one direction during drawdown and reverse and move in the opposite direction during injection. An example of this is shown in Figure 11. The figure shows modeled well displacements due to shear on a weak zone in the overburden above the South Belridge oil reservoir. This reservoir has undergone pressure drawdown from production and then repressurization from aggressive water injection.