Potential for CO_2 sequestration
and Enhanced Coalbed Methane production
in the Netherlands

Colophon

ISBN 90-5847-020-4

NOVEM Programme number 234.1: This work has been performed under contract with Novem BV, the Netherlands Agency for Energy and the Environment, in the framework of the programme “Feasibility of Carbon Dioxide Disposal and Coal Bed Methane Production in The Netherlands”, which is financed by the Ministry of Economic Affairs and the Ministry of Housing, Spatial Planning and the Environment.

Authors:

Carlo N. Hamelinck	Science, Technology and Society/Utrecht University
André P.C. Faaij	Science, Technology and Society/Utrecht University
Gerrit Jan Ruijg	Energy Research Foundation
Daan Jansen	Energy Research Foundation
Henk Pagnier	Netherlands Institute of Applied Geoscience TNO – *National Geological Survey*
Frank van Bergen	Netherlands Institute of Applied Geoscience TNO – *National Geological Survey*
Karl-Heinz Wolf	Applied Earth Sciences/Delft University of Technology
Omar Barzandji	Applied Earth Sciences/Delft University of Technology
Hans Bruining	Applied Earth Sciences/Delft University of Technology
Harry Schreurs	Netherlands Agency for Energy and the Environment

Utrecht, March 2001

Preambule

According to the Kyoto Protocol and the agreements made inside the European Union, the emission of carbon dioxide in The Netherlands has to be reduced by 6% in the year 2008. Related to the base year for these calculations, i.e. the year 1990, this means a reduction of 50 Mtonne of carbon dioxide. As decided by Government 25 Mtonne should be realised inside The Netherlands, whereas 25 Mtonne are to be realised outside the country through Joint Implementation and/or Clean Development Mechanism projects.
In the White Paper on Climate Change a list of options to reach the goal set is presented. Options are ranked according to applicability, readiness of the respective technology and contribution to the carbon dioxide reduction. Most probable options to reach the goal set are change of the type of fossil fuel (towards lowest carbon dioxide emission), reduction of the use of fossil fuels by high-efficiency processes and energy saving methods and the substitution of these fuels by so-called renewables and biomass.
In the context of that paper (the so-called Options Document) the disposal of carbon dioxide was named as one of the options for eventual future application. On the way of implementing the carbon dioxide reduction strategy the option of storage of carbon dioxide, with a focus on reuse or 'taken-advantage-of', has got an emerging position (W.J. Lenstra "Climate Policy, CO_2 Storage and Public Perception", 5th GHGC Conference, August 2000).

In co-operation between the Department of Economic Affairs and that of Housing, Spatial Planning and Environment in the Netherlands assignment was given to Novem to conduct a feasibility study and research. Goal was to research possibilities for storage of carbon dioxide in deep coal layers and parallel production of coal bed methane from these layers; the methane should be made profitable in an energy conversion system, based on (today available) best technology.
The execution of this combination of study and laboratory research was done in a consortium of the Netherlands Institute of Applied Geoscience TNO (TNO-NITG, National Geological Survey), Delft University of Technology (Applied Earth Science), University of Utrecht (Science, Technology and Society) and the Netherlands Energy Research Foundation ECN.
TNO-NITG and DUT concentrated on subsurface activities, UU and ECN concentrated on the surface activities; Novem took care for the overall co-ordination and international contacts. In addition a innovative research programme in co-operation between Novem and the Netherlands Organisation for Scientific Research (NWO), named “Transition to Sustainable Use of Fossil Fuels”, is on the go. A by-product of this exercise is the funding of a close operational partnership between parties of different working attitude and background; a special "thank you" to all partners should be given here.

The results of this project are encouraging. In clear language: this is a cheap and positive method to reduce emissions of carbon dioxide; as a by-product it delivers 'emission free' natural gas. This option can also offer a huge storage capacity for carbon dioxide, important to The Netherlands as some other options for storage are not applicable.
The exercise also showed several uncertainties on the technology side as on the jurisdictional side, whereas public acceptance and safety (transport, leakage) should be handled also. These items can be of influence on the economics and the applicability. Further study and research is necessary to minimise the margins and the risks before entering the realisation phase.
This document reflects the findings of this project. On this basis the government will make her decision if and how this option will be taken into real development.

Harry Schreurs, Novem BV

Abstract

This study investigated the technical and economic feasibility of using CO_2 for the enhanced production of coal bed methane (ECBM) in the Netherlands. This concept could lead to both CO_2 storage by adsorbing CO_2 in deep coal layers that are not suitable for mining, as well as production of methane. For every two molecules of CO_2 injected, roughly one molecule of methane is produced.

The work included an investigation of the potential CBM reserves in the Dutch underground and the related CO_2 storage potential in deep coal layers. The latter was also supported by laboratory experiments on the adsorption capacity of coal. Furthermore, an economic evaluation of ECBM recovery was made by analysing the costs of capturing CO_2 from major stationary sources and CO_2 transport, modelling the production of ECBM using CO_2 injection with reservoir simulations and system analyses to investigate the costs (and it's sensitivities) of gas production. Furthermore, the costs of on-site hydrogen and power production (including on site CO_2 removal and injection) were evaluated.

CO_2 sources in the Netherlands have been inventoried. Annually 3.4 Mtonne CO_2 can be captured from chemical installations and transported to sequestration locations at 15 €/tonne. Another 55 Mtonne from power generating facilities can be delivered at 40 to 80 €/tonne.

The technical potential of CBM in the Dutch underground is significant: a maximum reserve of about 60 EJ is stored in coal layers up to a depth of 2000 m. This figure should be compared to the current annual energy consumption of the Netherlands (about 3 EJ) or the known reserves of natural gas in the Netherlands (about 70 EJ in 1994). These reserves are concentrated in four main areas in the Netherlands: Zuid Limburg, the Peel area, the Achterhoek area and Zeeland.

The CO_2 storage potential could be about 8 Gtonne. This storage potential should be compared to the annual CO_2 emissions of the Netherlands: about 180 Mtonne. This means, theoretically, that the total CO_2 emissions of the Netherlands could be stored in coal layers for over 40 years and that CBM could meet the total national energy demand of the Netherlands for 20 years.

However, it is still uncertain to what extent these reserves can be accessed. With conservative assumptions regarding the potential completion and recovery rate of CBM from coal layers by means of drilling and CO_2 injection, as well as by limiting the ECBM recovery to a depth range of 500 – 1500 metres, the 'proven' reserves could be limited to 0.3 EJ and the 'possible' reserves up to about 3.9 EJ. The accompanying CO_2 that can be sequestrated than lays between 54 Mtonne and 0.6 Gtonne.

Although those figures are far more modest than the 'theoretical' potential, they are still significant. In case the 'possible' reserves can be accessed, ECBM could supply 5% of the current national energy use on a more than carbon neutral basis for over 25 years. Given the Kyoto targets for 2010, or the national targets for renewable energy, this is a very significant amount.

Without any subsidies or carbon taxes, the cost levels for ECBM recovery ranges from 3.5 to 6.5 €/GJ methane produced. These costs levels come close to the projected natural gas prices in Europe in a timeframe of 10 to 20 years, which are projected to be between 2.5 and 3.2 €/GJ. Inclusion of a carbon tax (or bonus) of 25 €/tonne CO_2 sequestrated, lowers the price of ECBM to a competitive 1.5 to 4 €/GJ. The cost level of CO_2 sequestration through ECBM is comparable with projected cost levels for CO_2 storage in aquifer traps(Steinberg and Cheng 1989) in case the CBM would be sold for current natural gas prices.

If the produced CBM is used for electricity or hydrogen production on top of the CBM field, the resulting CO_2 can be injected in the coal directly (thereby eliminating CO_2 transport costs). CO_2 removal from a gas engine or a combined cycle is currently more expensive when compared to CO_2 from industrial processes that must be transported to the CBM field. But a (SOFC) fuel cell produces a pure and therefore much cheaper CO_2 stream. Although SOFC fuel cells are not fully commercially available and have high capital costs, they could lead to somewhat lower costs of electricity. Without CO_2 bonus, on site power generation is more expensive than grid prices for the systems considered. But when a CO_2 bonus of 25 €/tonne CO_2 is assumed, power generation costs are reduced below 3 € cent/kWh, which is lower than the current average 3.2 € cent/kWh. On the longer term, when SOFC fuel cells could become cheaper, on site power generation could become a (very) attractive alternative.

On site (smaller scale) hydrogen production gives similar results. Capital costs for smaller scale on site hydrogen production are relatively high, but with a CO_2 bonus of 25 €/tonne, hydrogen costs could be lower than current production costs from coal and comparable to production costs from natural gas.

Overall, the results of the economic evaluation indicate that CBM by means of enhanced recovery by CO_2 injection in deep coal layers can be performed at competitive cost levels when the right system

configurations are chosen. A, relatively modest, carbon tax (or 'bonus') of 25 €/tonne could easily tick the balance in favour of ECBM recovery in Dutch conditions on short term already.

However, a number of important (geo) technical and geological factors play a key role in whether these cost levels can be obtained or not. The dominating factors in the costs are the drilling costs. In case the costs per wellhead appear to be higher than assumed here, the economic performance of the system deteriorates. On the other hand innovations in drilling techniques, gaining more experience with the required drilling methods over time and obtaining 'economies of scale' by drilling relatively large numbers of wells in a short time to exploit larger CBM fields may bring drilling costs (and thus CBM production costs) down considerably.
Regarding to the geology, the CBM potential and the actual accessibility of the, theoretical, coal reserves and the predicted presence of producable CBM gas in the coal layers is subject to broad ranges. More detailed surveys of the Dutch underground are needed to reduce uncertainties about CBM gas reserves. This can be obtained by seismic research and obtaining more and better samples of the Dutch underground. Such research is absolutely essential before ECBM is developed in the Netherlands on a significant scale.

In conclusion, this study showed that ECBM is likely to become an economically feasible option for the Netherlands on relatively short term. It could at least play a significant (and potentially very large) role in reducing greenhouse gas emission levels for a time period of about 50 years. Although the estimates of energy reserves in the form of CBM are uncertain, they are potentially very significant (varying from 6 – 60 EJ). The potential CO_2 storage capacity is (very) large as well (1-8 Gtonne of CO_2). Given the fact that CO_2 binds well to the coal matrix, that deep coal layers are unlikely to be accessed for mining or other activities in the future and that CO_2 storage with ECBM delivers a clean fossil fuel as a by-product, coal layers may be a preferable CO_2 storage medium when compared to (saline) aquifers, empty gas fields or in deep oceans.
Therefore, this option deserves further development and study. A mix of more detailed geological surveys combined with getting good quality samples, laboratory experiments, system studies on implementation scenarios and a pilot project (with a special focus on drilling techniques) is recommended.

Samenvatting

Deze studie heeft de technische en economische haalbaarheid onderzocht van CO_2 opslag in combinatie met koolbed methaangas winning (ECBM) in Nederland. Bij ECBM fungeren diepe ondergrondse kolenlagen als veilige netto koolstofopslagplaats, terwijl tegelijkertijd netto energie wordt geproduceerd. Iedere twee geïnjecteerde koolstofmoleculen leveren ongeveer één methaanmolecuul op. Het potentieel aan CBM reserves en CO_2 opslagcapaciteit in Nederland is geïnventariseerd. De opslagcapaciteit is mede onderbouwd door laboratorium experimenten aan de adsorptie eigenschappen van steenkool. Voorts is een economische evaluatie van ECBM uitgevoerd. De kosten van gasproductie en de bijbehorende gevoeligheden zijn onderzocht door het bepalen van de afvang en transportkosten van CO_2 uit stationaire bronnen, het modelleren van CO_2 gedreven CBM productie met behulp van reservoir simulaties, en een analyses van mogelijke systemen. De mogelijkheden voor on-site waterstof- en elektriciteitsproductie, waarbij gecoproduceerde CO_2 direct in de steenkool kan geïnjecteerd, is ook onderzocht.

CO_2 bronnen in Nederland zijn in kaart gebracht. Jaarlijks kan 3.4 Mton CO_2 afkomstig van chemische installaties à 15 €/ton worden geleverd op opslaglocaties. Nog eens 55 Mton afkomstig van kracht installaties kost tussen de 40 en 80 €/ton.

Het technisch potentieel van CBM in de Nederlandse ondergrond is significant; tot 60 EJ ligt opgeslagen in steenkoollagen tot een diepte van 2000 m. Ter vergelijking, het huidige energiegebruik in Nederland is ongeveer 3 EJ per jaar, in 1994 was de aardgasvoorraad 70 EJ. De CBM reserves bevinden zich met name in Zuid Limburg, de Peel, de Achterhoek en Zeeland.
Het CO_2 opslagpotentieel is 8 Gton. Dit getal moet vergeleken worden met de jaarlijkse nationale CO_2 emissies, ongeveer 180 Mton. Theoretisch kan dus de gehele nationale CO_2 uitstoot van 40 jaar in ondergrondse steenkool worden opgeslagen en met het geproduceerde CBM kan de nationale energievraag gedurende 20 jaar worden geledigd.
In hoeverre dit potentieel kan worden benut is echter onzeker. Met conservatieve aannamen voor welk gedeelte van de steenkool technisch aanboorbaar is tussen 500 en 1500 m en hoeveel van de hierin

aanwezige CBM gewonnen kan worden, daalt het ‘bewezen’ CBM potentieel tot 0.3 EJ en het ‘mogelijk’ potentieel tot 3.9 EJ. Tussen 54 Mton en 0.6 Gton aan CO_2 kan dan worden opgeslagen.
Ook al zijn deze getallen veel bescheidener dan de technische potentiëlen, zij zijn nog altijd belangrijk. Wanneer de ‘mogelijke’ reserves kunnen worden aangesproken, kan ECBM 5% van de nationale energievraag CO_2 neutraal leveren gedurende 25 jaar. In het licht van de Kyoto afspraken voor 2010, of de nationale doelen voor duurzame energie, is dit een belangrijke hoeveelheid.

Zonder subsidies of CO_2 heffing, kost het produceren van CBM door middel van CO_2 injectie tussen 3.5 en 6.5 €/GJ. Dit komt dicht in de buurt van verwachte aardgas prijzen in Europa over 10 tot 20 jaar (2.5 tot 3.2 €/GJ). Met een CO_2 heffing of bonus van 25 € per opgeslagen ton, daalt de prijs van ECBM tot een concurrerende 1.5 to 4 €/GJ. De kosten van CO_2 opslag in ECBM projecten, waarbij de CBM aan marktprijs wordt verkocht, zijn vergelijkbaar met verwachte kosten voor CO_2 opslag in aquifers.
Als de geproduceerde CBM wordt gebruikt voor elektriciteits- of waterstofproductie boven op het CBM veld, dan kan de gecoproduceerde CO_2 direct weer in de steenkool worden geïnjecteerd en worden transportkosten vermeden. CO_2 verwijderd aan een gasmotor of een STEG is duurder dan CO_2 uit industriële processen die naar het CBM veld moet worden vervoerd. Maar een SOFC brandstofcel produceert pure en daardoor goedkopere CO_2. Hoewel SOFC brandstofcellen nog niet breed commercieel verkrijgbaar en vooralsnog duur zijn, kunnen ze toch leiden tot lagere elektriciteitskosten. Zonder CO_2 bonus is on-site geproduceerde elektriciteit duurder dan elektriciteit uit het net. Maar 25 €/ton CO_2 bonus dalen de kosten voor opwekking tot minder dan 3 € cent/kWh, elektriciteit kost nu gemiddeld 3.2 € cent per kWh. Op de langere termijn, met goedkoper beschikbare brandstofcellen, kan opwekking ter plaatse een zeer aantrekkelijk alternatief worden.
On-site waterstofproductie op kleine schaal geeft vergelijkbare resultaten. Hoewel de kapitaallasten voor kleine waterstoffabrieken relatief hoog zijn, kan met een 25 €/ton CO_2 bonus de waterstof productieprijs dalen tot het prijsniveau van waterstof uit aardgas.
In het algemeen volgt uit de economische evaluatie dat CO_2 gedreven CBM productie kan plaatsvinden op een concurrerend kostenniveau wanneer de juiste systeemconfiguratie wordt gekozen. Een bescheiden bonus of taks van 25 €/ton vermeden CO_2 kan ECBM in Nederland aantrekkelijk maken.

Echter, enkele belangrijke (geo)technische en geologische factoren bepalen of deze kostenniveaus kunnen worden bereikt of niet. De kosten van ECBM projecten worden gedomineerd door de boorkosten. Indien de boorkosten per put hoger blijken te zijn dan aangenomen in deze studie, wordt de economische aantrekkelijkheid van ECBM minder. Aan de andere kant kunnen boorkosten wellicht behoorlijk dalen door innovaties, meer ervaring en schaalvoordelen.
Ook het potentieel aan koolbed methaangas en de winbaarheid ervan is onderhevig aan onzekerheden. De bandbreedte tussen ‘bewezen’ en ‘mogelijke’ voorraden is groot. Meer gedetailleerde inventarisaties van de Nederlandse ondergrond zijn nodig om onzekerheden te reduceren. Seismisch onderzoek en experimenten aan meer representatieve steenkoolmonsters moeten worden gedaan. Dit soort onderzoek is absoluut noodzakelijk voordat ECBM in Nederland op redelijke schaal kan worden ontwikkeld.

Concluderend heeft deze studie aangetoond dat ECBM waarschijnlijk een economisch aantrekkelijke optie voor Nederland kan worden op relatief korte termijn. Het kan minstens een belangrijke, en mogelijk een grote rol spelen in de reductie van broeikas gas emissie niveaus gedurende 50 jaar. Hoewel de schattingen voor CBM reserves onzeker zijn, zijn ze mogelijk zeer belangrijk (variërend van 6 tot 60 EJ). De mogelijke CO_2 opslagcapaciteit is ook groot (1 – 8 Gton). Gegeven het feit dat CO_2 sterk bindt aan de steenkool matrix, dat diepe steenkoollagen waarschijnlijk niet worden gebruikt voor mijnbouw of andere toekomstige activiteiten en dat CO_2 opslag met ECBM een schone fossiele brandstof als product levert, zijn steenkoollagen als CO_2 opslagplaats te verkiezen boven aquifers, lege gasvelden of oceaanbodems.
Deze optie verdient dan ook verdere ontwikkeling en onderzoek. Een combinatie van meer gedetailleerde geologische inventarisaties, laboratoriumonderzoek aan betere steenkoolmonsters, systeemstudies naar implementatie scenario’s en een pilot project (gefocust op boortechnieken) wordt aanbevolen.

Related reports

Barzandji OH, Wolf K-HAA and Bruining J, 2000, Combination of laboratory experiments and field simulations on the improvement of CBM production by CO_2 injection, proceedings of Second International Conference on Methane Mitigation, Novosibirsk.

Bertheux, WB, Wolf K-HAA, Barzandji O, Bruining J, 2000, CO_2-Enhanced coalbed methane production in dry and water saturated coals: experiments, simulations and image analysis, TU-DELFT – NOVEM Technical Report, Contract nr. 234130/9001.

De Haan MFE, 1999, Enhanced coalbed methane production by carbon dioxide injection; theory, experiments and simulation, TU-DELFT – NOVEM Technical Report, Contract nr. 234130/9001.

Harkes MP, Reimer K, David P and Veld H, 2000, Analysis of organic matter for a CO_2/CBM feasisbility study: Vitrinite reflectance, maceral analysis and Rock Eval analysis of selected samples, report nr. NITG 00-104-C, NITG-TNO, Utrecht.

Krooss BM, Gensterblum Y, Siemons N, Prinz D, 2000, Adsorption of methane, carbon dioxide and mixtures on dry and moist Carboniferous coals of different rank (in preparation), RWTH Aachen, Aachen.

Turkenburg WC and Hendriks CA, 1999, Fossil fuels in a sustainable energy supply: the consequence of CO_2 removal (in Dutch), Science, Technology and Society/Utrecht University, Report No NWS-99032, Utrecht, 28 pp.

van Bergen F, Pagnier HJM and David P, 2000, Inventory of potential volumes of methane extraction and carbon dioxide storage in coallayers in the Dutch subsurface; TNO contribution to the Feasibility study of combined coal bed methane production and carbon dioxide storage in the Netherlands, NITG-TNO, Utrecht.

Wolf K-HAA, Barzandji O, Bruining J and De Rooij M, 1999, Feasibility study of CO_2-sequestration and Coalbed Methane Production. Report on modelling work, economics and related laboratory experiments on enhanced coalbed methane production by liquid carbon dioxide injection., TU-DELFT – NOVEM Technical Report, Contract nr. 234130/9001.

Wolf K-HAA, Westerink HHE, Van Delft PTP and Bruining J, 1997, Coalbed methane production in the Netherlands; an inventory, TU Delft/NOVEM, Delft.

Wolf K-HAA, Barzandji OH, Bertheux W, Bruining J, 2000, CO_2-sequestration in The Netherlands. CO_2 Injection and CH_4- Production as related to the Dutch situation: Laboratory Experiments and Field Simulations, paper D5-3, in: Williams D (ed.), proceedings of Fifth International Conference on Greenhouse Gas Control Technologies, CD-Rom, CSIRO Div. Of Energy Technology, Cairns, Australia.

0 Contents

1 Introduction

Background

For the Netherlands meeting the Kyoto targets for greenhouse gas emission reduction appears to be very difficult. Main explanations are: Steady economic growth combined with disappointing progress with respect to energy efficiency improvement and implementation of renewable energy. CO_2 capture and disposal could serve as a backstop option for CO_2 reduction targets. In recent years increasing attention has been given to geological (underground) storage. CO_2 injection for enhanced methane recovery from underground coal layers is identified as a potential option for initial efforts to sequester CO_2 in a profitable way (Steinberg and Cheng 1989; Turkenburg and Hendriks 1999). In enhanced coalbed methane or ECBM, CO_2 is injected in coal seams and displaces the sorbed methane present at the internal surface of coal layers. The idea is that, at least, two molecules of CO_2 can be sequestered for every released molecule of methane (Gunter et al. 1997). This implies that (deep) coal layers can be net carbon sinks, while at the same time be a net producer of energy. Furthermore, since the majority of CO_2 is adsorbed to the coal surface with a near liquid density, subsurface coalbeds may provide a inherently safe CO_2 storage medium.

Previous work on ECBM has been done in the United States' San Juan basin, New Mexico. Since 1996 the Texan company Burlington Resources has injected CO_2 into the basin and preliminary results show an increase of coalbed methane production of 75% after full field development. A second demonstration of ECBM is located in Alberta, Canada and run by the Alberta Research Council (Reichle et al. 1999).

The Netherlands is for the larger part underlain with Carboniferous deposits with numerous coal seams that are likely to contain methane. Earlier publications give estimates of total coalbed methane reserves in the Netherlands of 27 EJ, twice the original content of the Slochteren Natural Gas Field (Barzandji et al. 2000). Even if only a small part of this gas could be produced with ECBM with CO_2 sequestration, this would imply an enormous storage capacity for CO_2. The coal beds have the advantage that storage of CO_2 is combined with the production of energy that would otherwise not be utilised, since the coal resources in question are, under normal economic conditions, not commercially recoverable by mining.

This study

This study explores the technical and economic feasibility of ECBM in the Netherlands. The potential and the economic performance are worked out for several ECBM recovery concepts and technological issues are outlined. The research includes the following main activities:

- Inventory of CO_2 sources in the Netherlands and techno-economic analysis of CO_2 removal and transport. Several scenarios for CO_2 transport of different capacities and distances will be assessed.
- ECBM production locations are determined by analysis of coal reserves and their characteristics. Four potential areas are assessed: one in eastern Gelderland, two in Limburg and one in Zeeland.
- Description of ECBM theory and production technology resulting in a time dependent model for ECBM production and CO_2 injection.
- Selection and description of various ECBM production/CO_2 sequestration systems. Systems considered include direct delivery of methane to the natural gas grid, production of power (on various scales) and hydrogen.
- Information from the location assessment is combined with modelling results. Costs of CO_2 sequestration are calculated for various scales and configurations.
- Evaluation of main uncertainties, environmental impacts and sensitivity analyses.
- Comparison of CBM production systems with reference systems and exploration of potential implementation schemes in the Dutch context.

Organisation

This study was co-ordinated and tendered by NOVEM for the ministry of Economic Affairs (EZ) and the ministry of Housing, Spatial Planning and the Environment (VROM). The project was commented upon by an expert panel consisting of Gasunie, BP Amoco, EBN, Gastec, NAM, Nogepa, Shell, and professor Schuiling of Utrecht University.

The producible coalbed methane potential and the potential CO_2 storage capacity of the Dutch underground has been inventoried by the Netherlands Institute of Applied Geoscience TNO (TNO-NITG) and is reported in a separate report (van Bergen et al. 2000). Applied Earth Sciences of the Delft University of Technology investigated the diffusion behaviour of CO_2, CH_4 and water in coal, by means of laboratory experiments (published earlier: Wolf et al. 1999a) and performed field scale simulation of both primary and enhanced coalbed methane production (Barzandji et al. 2000). The relating work and reporting was carried out by Science, Technology and Society of the Utrecht University (STS-UU) in close co-operation with the Energy Research Foundation (ECN).

2 CO_2 supply in the Netherlands

2.1 Inventory of CO_2 sources

Operation of ECBM requires a supply of CO_2. Larger point sources and those with a high CO_2 concentration in flue or exhaust gases are of most interest, because CO_2 removal from small sources with low load factors is uneconomic on forehand. This chapter gives an inventory of CO_2 sources from power generation, waste incineration and several industries in the Netherlands, and their main characteristics. The aim of the inventory is to determine which point sources are economically most attractive.. With this information, including the location of these sources, one can determine the length and capacity of pipelines required for CO_2 transport to the possible CBM locations. The logistics will be dealt with in the next chapter.

Table 2-1 gives the main characteristics of the major categories of CO_2 sources. An inventory of sizes of power generating installations throughout the Netherlands was supplied (Bruggeman 1994). The range of 6 - 21 wt % CO_2 in the flue gas stream of power plants can be captured by chemical absorption with Monoethanolamine (this will be described in detail in §2.3.1). With this process between 84.5 and 86.2 % of the CO_2 can be captured (Stork Engineering Consultancy BV 1999). The annual amount of possibly captured CO_2 per installation follows from multiplying the size with the flue gas rate, the CO_2 concentration, capture percentage and the annual load. Some chemical plants emit CO_2 in a pure form and do not require an additional CO_2 removal step.

In Annex B all inventoried point sources are summarised. In cases where more installations where found on one site, a total CO_2 stream was calculated. More installations in one city but on different sites have been studied separately. Only sites with an annual emission of more than 40 ktonne CO_2 are taken into account. The total inventoried potential of captured CO_2 is 56 Mtonne annually, which is about 30% of the total CO_2 emission in the Netherlands (RIVM 1999). Also shown in the Annex are the parameters relevant for the cost calculation of CO_2 capture and preparation: the scale in Mtonne CO_2/year captured; the CO_2 fraction in the stream; the annual operation time of the plant; and the future period in which the plant is expected to remain operational.

Table 2-1. Characterisation of plant types, summarised CO2 flow per sector and range of costs for CO2 capture.

	Typical load (h/y)	**CO_2 concentration**	**Capture method**	**CO_2 total (Mtonne/yr)**	**CO2 cost (€/tonne CO_2)**
Power plants					
Pulverised Coal boiler	4000 – 8000	21 wt %	MEA	18	35 – 50
Integrated Coal Gasification Combined Cycle	8000	13 wt %	MEA	1.3	40
Gas fired Conventional Steam Cycle	500 – 4500	15 wt %	MEA	7.9	45 – 60
Gas fired Combined Cycle	5000-8000	6 wt %	MEA	11	45 – 60
Industrial power supply					
Combined Cycle	7000	6 wt %	MEA	14	45 – 80
Gas Turbine with exhaust boiler	7000	6 wt %	MEA	1.0	45 – 80
Steam Turbine	600 – 8500	15 wt %	MEA	0.5	45 – 80
Waste Incineration					
AVI	8000	17 wt %	MEA	3.1	40 – 50
Chemical plants					
NH3	8200	100 wt %	none	2.1	4 – 5
H2	8200	100 wt %	none	1.1	4 – 5
EO	8200	100 wt %	none	0.2	4 – 5

2.1.1 Power plants

Technical descriptions of different of power plant types are given by Stork Engineering Consultancy (1999), including plant efficiencies, flue gas flow rate and CO_2 content.

The pulverised coal fired power plants in the Netherlands have steam turbine cycles. These plants are typical base load units with an operation time of 7000 h/y, because of their low fuel costs. Most of the

PC power plants are originally planned to be decommissioned between 2010 and 2015, which can result in relatively short depreciation periods for CO_2 removal equipment.

The Netherlands has one integrated coal gasifier combined cycle (IGCC) in Buggenum. This is a base load unit with even lower fuel costs than pulverised coal fired power plants, due to the higher electrical efficiency. Average full load time is high: 8000 hours/year.

Two types of gas fired power plants are operational in the Netherlands. The older conventional gas fired steam cycle plants are gradually replaced by combined cycles. Velsen is the last conventional plant to be decommissioned, in 2011, too early to make it profitable to apply CO_2 capture. Moreover these conventional plants have higher marginal costs than combined cycles, so in the near future they will be increasingly used for peak load capacity.

Most combined cycle power plants are middle-load units. Typically, their average full load time is some 6000 hours/year. The smaller ones operate as district heating systems, and are heat demand controlled. Their full load time is generally shorter: about 5000 hours/year.

Future energy scenarios show a slow growth of the total installed power generating capacity (Kroon et al. 1998). All the central power production, which is not coal-fired, will consist of combined cycles by the year 2012 (EC scenario). Often the plants will be located near industrial sites for the delivery of process steam. After the year 2005 new combined cycle plants may be built in the Netherlands. Increase of average electrical efficiency is expected to cause a decline in the production of CO_2 in the electricity generating sector in the Netherlands. The CO_2 emissions of natural gas fired central power production are expected to decline from 37,4 Mtonne/year in the year 2000 to 37 Mtonne/y in the year 2005, 36 Mtonne/y in the year 2010, and 31 Mtonne/year in the year 2020 with a capture potential of respectively 32, 31½ , 30, and 26 Mtonne/year.

2.1.2 Industrial power supply

At present some 5,4 GW of CHP power is installed in industry (Bruggeman 1994). A diversity of conversion techniques is used. There are combined cycles, gas turbines with exhaust boilers, and steam turbine installations of different sizes. Since electric efficiencies and the load factors are not known in detail for all plants, these figures are estimated. The average efficiency of a stationary gas turbine is assumed to be 33%, and the average full load time 7000 h/yr. The total annual CO_2 emission of industrial power installations is 17 Mtonne.

There are three trends in industrial CHP, which compensate each other more or less. The first is an increase in installed electricity generating capacity. The other trends are increase in electric efficiency of the CHP units, and increase in process efficiency, leading to decrease of the heat demand. Because of this balance, CO_2 emissions on all locations in industry are expected to remain more or less constant on the current level over the next decades. In time most gas turbine and steam turbine installations will be replaced by combined cycles.

2.1.3 Waste incineration

Another important source of CO_2 in the Netherlands is waste incineration. 11 Waste incineration plants have an installed electricity generating capacity of 400 MW, and operate as base load facilities. Since half of the heating value of the waste is of organic origin, capture of CO_2 from waste incinerators can result in negative CO_2 emissions. Or in other words: more CO_2 is captured than the fossil carbon content of the fuel.

The flue gas from AVIs contains less CO_2 than the flue gas from Pulverised Coal boilers because of a larger excess air. We assume the CO_2 fraction to be 12 volume %. The existing incineration plants will not be decommissioned in the short term.

2.1.4 Industrial sources

Three kinds of industrial processes applied in the Netherlands deliver a pure CO_2 discharge because CO_2 is co-produced with the (intermediate) product and is separated in the process. These processes are: Fertiliser production, hydrogen production and ethylene oxide production.

NH_3: fertiliser

The production of nitrogen-fertilisers is a large-scale industrial activity and the production of ammonia for fertiliser is an important source of pure CO_2. In 1998 the annual ammonia production of the main three plants in the Netherlands amounted to 2.65 Mtonne (Chemical Week 1998).

By means of a chemical absorption process, approximately 1.2 tonne of carbon dioxide is removed during the production of 1 tonne of ammonia. The amount of CO_2 potentially available for applications such as CBM recovery depends on the form of the fertiliser produced. If the desired product is ammonium nitrate, all the by-product CO_2 is available. If instead the desired product is urea, part of the separated CO_2 is needed for urea manufacture (Williams 1998). Approximately 750 kg of CO_2 is used for the synthesis of 1 tonne of urea. If the urea is used for melamine production, part of the CO_2 and NH_3 (in a 1:2 ratio) is released and used over again in the urea process or elsewhere. There is also a diluted CO_2 emission from heating purposes (38 % of total plant CO_2 emission) which could be recovered by means of an absorption process. This emission is however not taken into account.

At present the recovered CO_2 part is vented to the atmosphere or liquefied in order to be sold (mainly to the food and beverages industry). Based on estimates of recovery and use, the amount of CO_2 that is recovered and subsequently vented to atmosphere amounts to approximately 3 Mtonne CO_2 per year (Farla et al. 1995). Production numbers of CO_2 for the three main plants are given by Wildenborg et al. (1999). The CO_2 is available at a pressure of 1.3 bar and a temperature of 35 °C; it is saturated with water (5%) and contains traces of nitrogen (300 ppm), hydrogen (1500 ppm) and traces of methane (Farla et al. 1995).

H_2: hydrogen

Hydrogen is used primarily in the oil and chemical industries for applications aimed at upgrading crude oil through desulphurising and hydrocracking to form lighter fractions. The chemical industry also uses hydrogen where it is required as a reactant in many large-scale processes. In the future hydrogen may become an important fuel for the transport sector and possibly an alternative for natural gas.

The production of hydrogen is mainly done by suppliers of industrial gasses like Air Liquide, Air Products and BOC. These companies steam reform natural gas. However, the most interesting are the bigger production sites: Shell Pernis, where residue gasification is applied in the Per^+ process; and Esso Rotterdam where catalytic reforming of natural gas is applied (Wildenborg et al. 1999). The eventually produced hydrogen is separated from the other components in the gas stream using two sets of pressure swing adsorption (PSA) beds. Nearly all CO_2 and water is separated in the first set. The second set separates 86 % of the hydrogen. By recycling some of the remaining gas from this second bed to the first, the overall hydrogen recovery can be higher. The PSA unit produces three separate streams: hydrogen up to 99.999% pure, an undiluted and combustible purge gas, and high purity CO_2 at about 1.3 bar (Blok et al. 1997).

EO: ethylene oxide

Ethylene oxide (also called oxirane) is mainly produced as a chemical intermediate to produce ethylene glycol and ethoxylates. The production of EO in the Netherlands, at Dow Terneuzen and Shell Chemicals Moerdijk, accounts for only a very small fraction of the total fuel consumption in the petrochemical industry. The process is of interest however, because a concentrated CO_2 stream is separated during production.

Per tonne of ethylene oxide, approximately 0.88 tonne of CO_2 is formed as a by-product, by complete oxidation of part of the ethylene (Farla et al. 1995). In 1998 the annual Dutch production of EO was 390 ktonne: 150 ktonne at Dow and 240 ktonne at Shell (Chemical Week 1998). Shell Moerdijk shows a large variation in capacity through the years. Since also part of the CO_2 is sold, it is assumed that only 100 ktonne CO_2 will be available annually. For Dow the availability of CO_2 is assumed to be 130 ktonne/year (Wildenborg et al. 1999).

The CO_2 flow is released at atmospheric conditions and contains only traces of methane, ethylene and ethylene oxide; the moisture content is high. After recovery the only steps needed for transport, will be water removal and compression.

2.2 Other CO_2 sources

Steel production at Corus, formerly Hoogovens, IJmuiden is a large source of CO_2. At present the CO_2 rich blast furnace gas and basic oxygen furnace gas are partly reused as a fuel in the steel production process. Hence the CO_2 is emitted at various points in the process and becomes expensive to capture. The remaining part, with a carbon content equivalent to over 3.6 Mtonne of CO_2, is sold to the Velsen IJmond power station and, as such, included in Table B-1. Even when this power station is decommissioned, the CO_2 emission will remain for longer time into the future (Farla et al. 1995).
Small point sources like the heavy chemicals industry (1.5 Mtonne/year divided over 71 plants) and the construction materials, pottery and glass industry (1 Mtonne/year, 74 plants) are not included in this study, because those sources are considered too small in terms of CO2 volume to be economic.

2.3 Capture and preparation

2.3.1 CO_2 capture

In some cases CO_2 is released as a pure process stream and can directly be prepared for transport (see §2.3.2). In most cases, however, when CO_2 becomes available in diluted form (as in flue gas after combustion), it first has to be captured from the gas. For this purpose different physical and chemical processes are available. A more extensive overview of such processes is given in Annex A. Chemical absorption using amines is the most conventional and commercially best-proven option. Physical absorption, using Selexol, has been developed since the seventies and is an economically more attractive technology when the flue gas contains higher concentrations of CO_2. As a result of technological development the choice for one technology or another could change in time, e.g. membrane technology or still better amine combinations could play an important role in future. Such advanced technologies are not considered in this study though.

The capture method used in this study is chemical absorption using amines because this method is especially suitable when CO_2 partial pressures are around 0.1 bar. Figure 2-1 gives a simple process diagram of a MEA based system. It is a technology that makes use of chemical equilibria, shifting with temperature rise or decline. Basically, CO_2 binds chemically to the absorbent at lower temperatures and is later stripped off by hot steam.

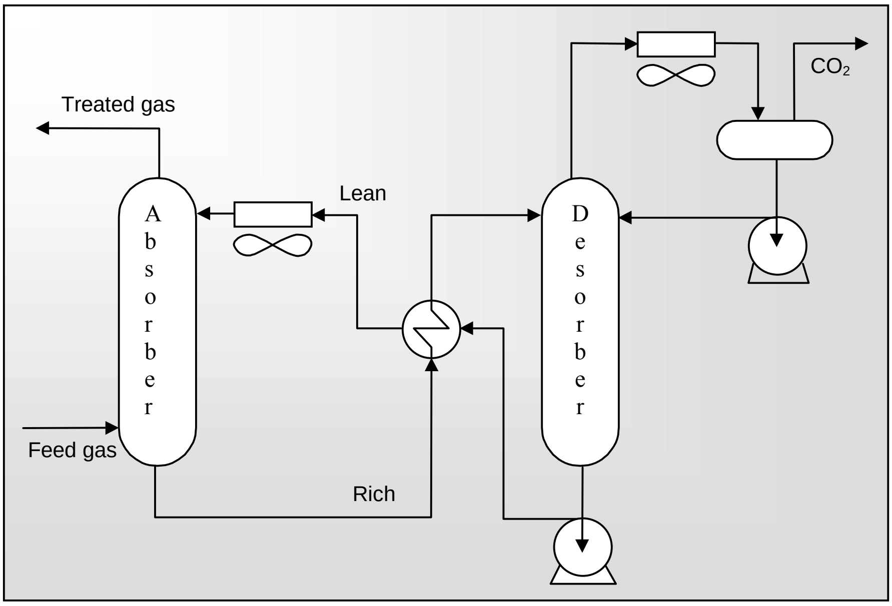


Figure 2-1. The Fluor Daniel Econamine system (Hydrocarbon Processing 1998).

The cost of amine based capture are determined by the cost of the installation, the annual use of amines, the steam required for scrubbing and the electric power. Cost figures from the commercially applied Fluor Daniel Econamine process are used in this study (see Annex A). There is influence of scale and a strong dependence on the CO_2 concentration as can be seen in Table 2-2.

Table 2-2. Total investment in €/annual tonne CO_2 for an amine based capture system. For two different CO_2 levels. Annual load is 7000 hours.

	Concentration	4.0 %	13 %
CO_2 captured			
0.50 Mtonne/year		115	69
5.0 Mtonne/year		73	44

2.3.2 Compressing, drying and cooling

For transportation the carbon dioxide should have a high density. Assuming a temperature between 10 and 20 ° C in the pipeline, the CO_2 pressure needs to be at least 80 bar at the pipeline entrance, given a maximum pressure drop of 10 bar during transport. The transported CO_2 will be in supercritical conditions and is not allowed to cross to the gas phase, because this would cause cavitation and a rise in volume. The CO_2 must be dried to a water content of 10 ppm in order to prevent corrosion in the pipeline (Hendriks 1994; Wildenborg et al. 1999).

The compression is performed by using a multistage compressor with a cooling step after each stage. At least four stages, with each a compression ratio of 3, are necessary for compression from atmospheric to 80 bar, but depending on the throughput and set-up, five or six stages could be necessary. With available cooling water at 20 ° C the intercooling can be down to 35 °C. Since the carbon dioxide / water mixture is corrosive, the material used is stainless steel. Investment costs amount 23 M€ for a compressor with a capacity of 250 tonne CO_2 / hour (Wildenborg et al. 1999); a scaling factor of 0.75 has been applied (Faaij et al. 1998). The required shaft power is 340 kJ/kg CO_2, delivered as electricity or, when available, steam.

Most CO_2 streams are saturated with water, but most of this water will be removed during the first compression stages. After the second stage the water content of the CO_2 will be very low (approx. 1000 ppm up to saturated: 2600 ppm). However, additional drying is necessary to meet the specifications for transport. Therefore the CO_2 passes through a drying tower containing a solid desiccant, where the CO_2 is dried to a water content of 10 ppm. Per tonne of CO_2, 0.8 kg of water is removed during dehydration. The desiccant is regenerated by passing hot CO_2 through the drying tower. Dehydration requires 8 kJ/kg CO_2 in the form of steam (Farla et al. 1995).

After the last compression stage, the carbon dioxide is cooled to 20 °C with cooling water. For cooling further to 10 °C a small refrigeration step is needed. The energy demand for circulating and compressing the refrigeration fluids is estimated to be 8 kJ_s/kg CO_2 (Farla et al. 1995).

2.4 CO_2 costs at major point sources

The investment costs for CO_2 capture and preparation installations are a function of the volume of CO_2 recovered per unit or time and the CO_2 concentration in the flue gas stream. The annual capital costs depend on the lifetime of the installation in question. The interest rate used is 5%; the average lifetime is 18 years. Operating and maintenance costs amount 5 % of total investment per annum. Further costs are represented by MEA demand for the capture system and in the energy demand; the capture system consumes a small amount of electricity, and all parts of the installation consume steam. Electricity costs 5 € cent/kWh_e and steam 2 € cent/kWh_s.

The annual costs of a capture and preparation system divided by the annual CO_2 stream gives the costs per tonne of CO_2 captured. Costs for CO_2 removal at some typical point sources are given in Table 2-3.

Table 2-3. Typical costs for CO_2 capture and preparation for transport.

	amount CO_2 captured	**Capture €/tonne**	**Preparation €/tonne**
130 ktonne H2/year plant	1 Mtonne	-	3,6
600 MW PC boiler	2,4 Mtonne	36	3,7
50 MW waste incinerator	330 ktonne	37,5	4,3
20 MW industrial CC	54 ktonne	49,2	5,5

The costs of captured CO_2 ready for transport for all inventoried major point sources of CO_2 in the Netherlands are listed in Table B-1. From the data in this table a supply curve is constructed (Figure 2-2). The point sources are arranged in order of increasing CO_2 price and represented with a horizontal line in the marginal cost curve. The average gate price for the first N cheapest Mtonne can be found in the lower curve.

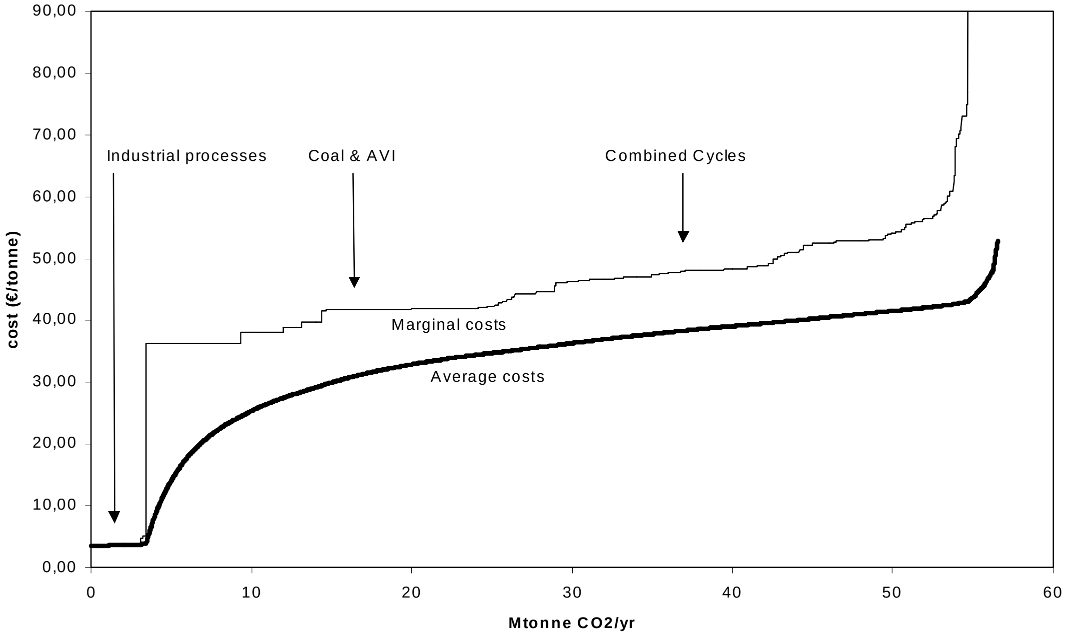


Figure 2-2. Supply curve of CO_2 in the Netherlands.

The supply of pure CO_2 from industrial processes for hydrogen, ammonia or ethylene oxide production costs around 4 €/tonne. CO_2 from coal fired power generating facilities and waste incinerators is more expensive: 36 to 50 €/tonne and CO_2 from combined cycles costs 45 to 70 €/tonne. Farla et al. (1995) previously reported CO_2 supply costs of 8 US$_{1995}$/tonne CO_2 in ammonia production, 9 US$_{1995}$ in EO production and 13 US$_{1995}$ in hydrogen production. The difference may be explained by the higher pressure, 110 bar in stead of 80 bar, and the use of electricity in stead of steam for driving the compressor.

Hendriks investigated the CO_2 capture possibilities from an Integrated Coal Gasifier/Combined Cycle plant, using the physical absorbent Selexol. Between the gasification section and the gas turbine, the CO in the fuel gas is first shifted to CO_2, after which the CO_2 is removed. In this way overall carbon recovery rates of over 96 % can be reached. This approach strongly influences the heating value of the coal gas as well as the heat balance of the system, but on the other hand the CO_2 capturing method is cheap and relatively efficient. Taking into account the efficiency loss and the costs for shift and Selexol, the CO_2 'ready for transport' from ICGCC would cost between 14 and 20 US$_{1990}$, or 19 and 27 €$_{2000}$ (Hendriks 1994).

3 CO_2 Transport

Figure 3-1 shows the locations of CO_2 point sources plotted on a map of the Netherlands. Suitable locations for ECBM with CO_2 sequestration are Dorth (Achterhoek), Kessel (Peel), and Geleen (Zuid Limburg) as will be explained in detail in §4.2. The aquifer near Hoogkarspel was studied as a sequestering location by (Wildenborg et al. 1999).

CO_2 is transported from a point source to a sequestering location by means of a pipeline. Independent of the distance the pressure drop on the track is allowed to be 10 bar (from 80 to 70 bar) maximally. There are no booster stations. Depending on the transported quantity and the distance, the pipe diameter varies from ten centimetres up to sixty-five. The algorithm to calculate the required pipe diameter is described in Annex C.

Investment costs for a pipeline consist of material and construction costs. They are a proportional function of the distance and depend less than proportional on the diameter. Investment ranges from 0.22 M€/km (15 cm diameter) to 0.86 M€/km (70 cm) (Wildenborg et al. 1999). Operating and maintenance amount 2.1 % of the total investment. Table 3-1 shows several typical values for the costs of CO_2 transport in relation to capacity and distance.

Table 3-1. Pipeline diameter and price per tonne CO_2 transported (IR = 5%, payback in 20 years).

Distance	50 km		300 km	
Volume				
0.1 Mtonne/year	0.10 m	9.2 €/tonne	0.15 m	66 €/tonne
0.5 Mtonne/year	0.20 m	2.6 €/tonne	0.30 m	21 €/tonne
1 Mtonne/year	0.25 m	1.5 €/tonne	0.35 m	12 €/tonne
5 Mtonne/year	0.45 m	0.5 €/tonne	0.65 m	4.7 €/tonne

The transported CO_2 could amount between 40 ktonne/year for an ECBM pilot and several Mtonne/year for a fully developed area, for a period of 40 years. This will be discussed in detail in chapter 4 and 5. In these cases one pipeline from a cheap CO_2 source in Geleen or the Europoort to a sequestering location would be sufficient for operating an ECBM production scheme.

In the situation that CO_2 storage would be applied on larger scale in the Netherlands, with not only more ECBM production but also large scale sequestration in aquifers, a CO_2 grid could become a reality. This implies that numerous CO_2 emitting point sources are connected to a CO_2 transport network, leading to an on average large-scale collection and transport system. In such a situation, CO_2 transport needed for ECBM would become relatively cheap due to economies of scale. In this case the lower cost figures mentioned in Table 3-1 would apply. Such a CO_2 infrastructure could have a layout as suggested in Figure 3-1. This layout is roughly based on the current natural gas distribution network. The distances mentioned in Figure 3-1 are used to calculate CO_2 supply costs from point sources to potential ECBM production fields.

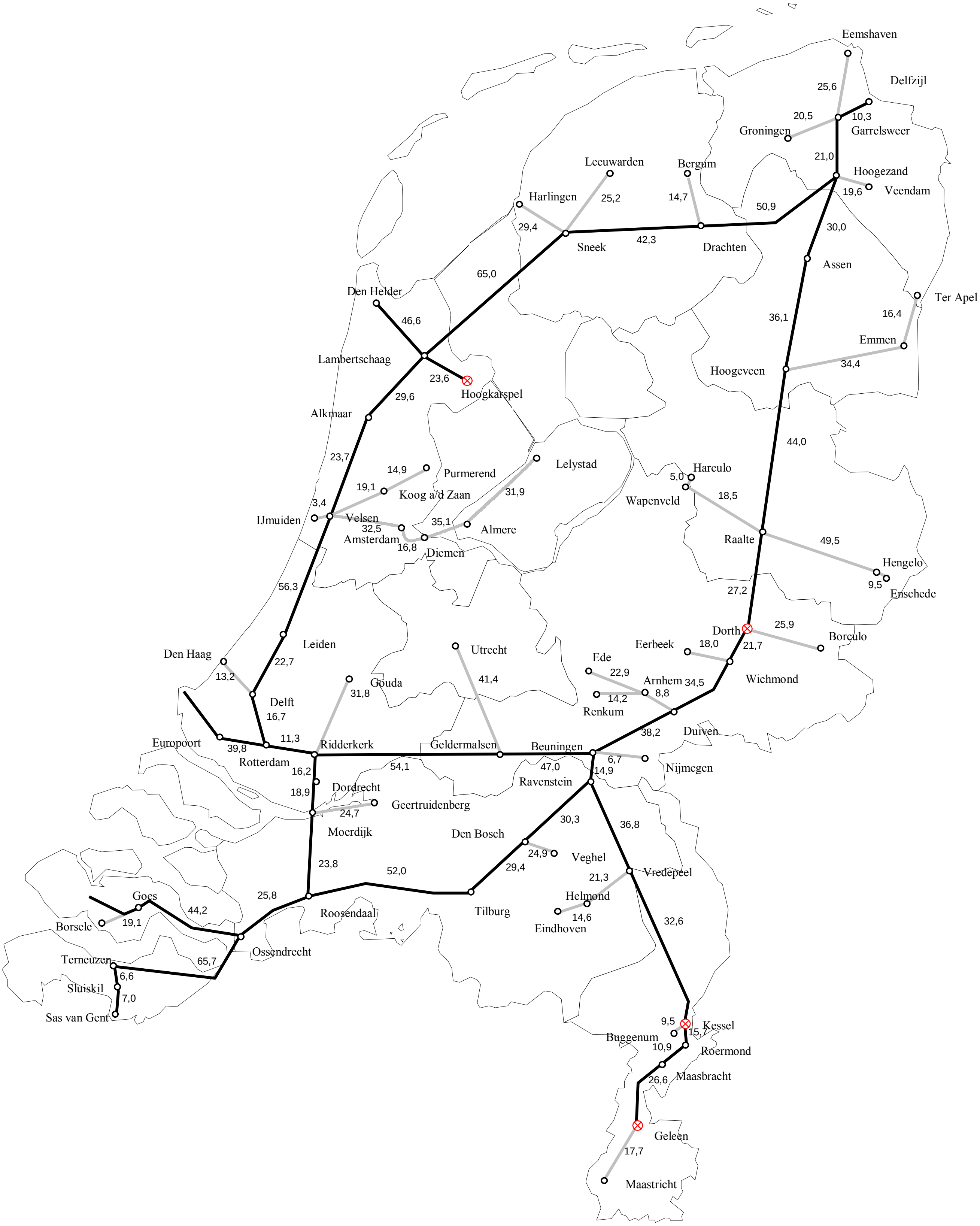


Figure 3-1. Spreading of CO_2 point sources over the Netherlands, distances in km (centre to centre, via main roads).

4 Potential of Enhanced Coalbed Bed Methane

4.1 Introduction

Coal forms by the compaction of plant material over a long period in time. Gases, including methane, are generated during this process and are either adsorbed on the coal surface or are dispersed into the pore spaces around the coal seam. The amount of gas formed depends on the temperature and pressure conditions that the coal was subjected to during geological history. The great benefit of a coal as a reservoir rock is that it, up to a certain depth, can contain much more gas than a sandstone gas reservoir with comparable volume and porosity Disadvantage is that it is much more difficult to produce the gas from the reservoir.

Originally, in the early 1940s in Europe, coalbed methane extraction was used for degassing exploitable coal, in order to improve safety for the miners. Degassing is carried out by pumping away the groundwater until the reservoir pressure in the coal is low enough to initiate desorption of methane and cause the gas flow. When hard coal production declined, the interest in recovery and utilisation of coalbed methane increased (CBM) as an alternative for the exploitation of former coal mining areas. Better well stimulation techniques and special drilling techniques were developed (Schneider and Preuße 1995).

Production of coalbed methane can be enhanced by means of CO_2 injection. Carbon dioxide adsorbs more easily to the coal matrix than methane. Therefore, injected carbon dioxide drives extra CBM from the coal seams while at the same time reservoir pressure is maintained. Enhanced coalbed methane (ECBM) production is currently demonstrated in the United States and Canada. Results indicate that with ECBM up to 75% more methane can be recovered than with CBM degassing only (Reichle et al. 1999; IEA Greenhouse 1998).

Experiments at the Delft University of Technology show that, under optimal pressure and temperature conditions, each adsorbed methane molecule in the coal can be replaced by at least two carbon dioxide molecules (see Annex F and §4.3.2). In addition to replacing CH_4 by CO_2, the coal cleats can be filled up with CO_2, which increases the CO_2 storage potential further. This makes the coal a net CO_2 sink, because more carbon can be stored than CH_4 is produced. Therefore ECBM could be an economically attractive CO_2 disposal technique: CO_2 injection costs could be offset by CH_4 yields. Coalbeds have proven that they are able to hold gas for millions of years. This could make CO_2 storage in coalbeds more attractive than storage in other potential subsurface media, e.g. aquifers, which naturally do not contain gas and have therefore not yet proven their gas storage capacity.

This chapter first assesses the potential for ECBM in the Netherlands by studying the coal, its producible coalbed methane content and carbon dioxide storage capacity. In §4.3 CO_2/CH_4 exchange theory is combined with ECBM production technology, leading to a model describing CO_2 enhanced coalbed methane production throughout time.

4.2 Dutch potential for ECBM

Not all coal in the underground is suitable for ECBM. (IEA Greenhouse 1998) give a list of reservoir characteristics that are important for ECBM recovery:

- The coal seam should be laterally continuous and vertically isolated from surrounding strata.
- It should be minimally faulted and folded.
- Moderate permeability is necessary for effective ECBM (1 to 5 mDarcy).
- Coal seam depths of 300 – 1500 m are considered appropriate for CBM, shallower reservoirs tend to be low in reservoir pressure and thus low in gas content, whereas deeper reservoirs suffer from diminished permeability.
- Concentrated coal deposits (few, thick seams) are generally favoured over stratigraphically dispersed (multiple, thin seams) measures.
- Coal reservoirs that are saturated with methane are preferred from an economic point of view. Undersaturated areas can experience delay in methane production, although CO_2 injection could reduce delays by increasing saturation. With respect to CO_2 sequestration, undersaturated coal seams can still serve as effective reservoirs.

4.2.1 Area selection

For this study the Netherlands Institute of Applied Geosciences TNO made an inventory of potential CBM and CO_2 storage in the Netherlands. The method used and results are more extensively reported in (van Bergen et al. 2000); a description of the applied method is given in Annex D. First those areas that have potential for Enhanced Coalbed Methane Production with CO_2 storage are identified. Only those areas with top of the Carboniferous within 2000 m of depth, are considered. Below this depth the permeability of the coal seams will be too low for both CBM production and CO_2 injection and drilling costs too high. Based on this depth criterion four areas have been selected for further study: the Zuid-Limburg area, the Peel area, the Zeeland area, and the Achterhoek area (Figure 4-1). Of these four areas only the Zuid-Limburg area has been actively mined in the past. Within the four areas fault-bounded blocks were determined using seismics. Extension of the coal seams is assumed to be continuous within these fault-bounded blocks. Blocks were defined, if possible, by fault throws of ca. 50 meter, based on available seismics and seismic resolution. In the Zeeland area, which is structurally a relatively stable area, there are only a few seismic lines available. Therefore the area is not divided into smaller blocks.

The major part of the Dutch territory lies within the Northwestern European Coal Basin. The most important coal bearing deposits in the Netherlands are the Upper Carboniferous (Westphalian A to Late Westphalian C) sequences. These sequences are present throughout the major part of the Netherlands at various depths with total thickness up to 3000 m. Potentially every tenth meter in the Westphalian A and B sequences a coal horizon can be expected (Pagnier et al. 1987).

The thickness of the coalbeds is of great importance for ECBM production, because thick coalbeds mean larger volumes and thus more gas. Also advanced production techniques are easier to implement in thick coalbeds. The available data that can be used for the determination of the (thickness of the) coal seams are limited. The resolution of the seismic data is too low to be used for thickness evaluation of individual coal seams. The thickness information used in this study was mainly derived from exploration wells for oil, gas and coal. Only in the Zuid-Limburg area data from the old mining activities are available. Based on five wells drilled for a coal inventory study in the Achterhoek and the Zuid-Limburg areas, the mean thickness is known to be 1 m for coal seams (> 50cm), with a maximum of ca. 3.5 m.

The limited number of exploration wells for oil and gas that reached the Carboniferous were evaluated for coal using geophysical well logs. For log interpretation, and especially for coal thickness evaluation, a recently developed statistical tool was applied, based on Bayesian statistics.

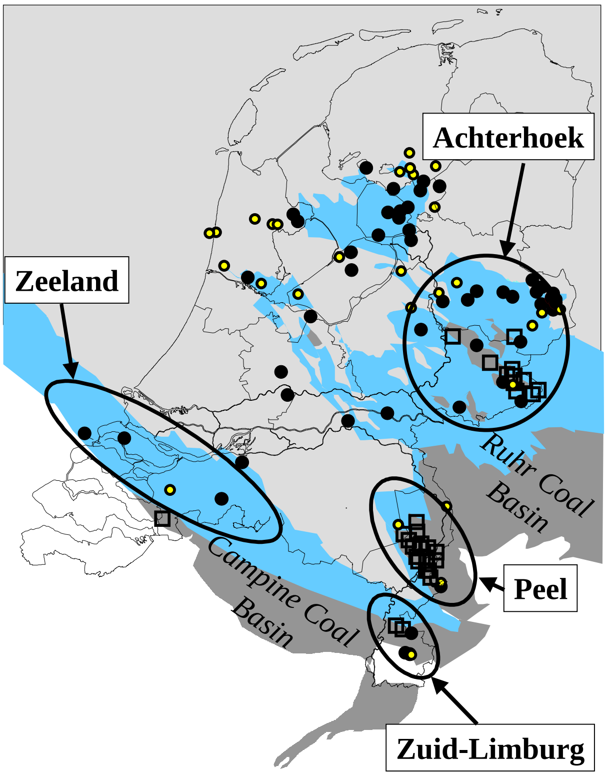


Figure 4-1. Map of the top of the Carboniferous with selected wells for the inventory. All indicated wells have top Carboniferous not deeper than 2000m. Based on this map four areas have been selected and indicated on the map.

4.2.2 In situ gas content

The major part of the methane in the coal is in the adsorbed phase. In this study only existing information and old coal samples are available, excluding direct measurements of the gas content of the coals. The gas content is therefore estimated by indirect methods, using Langmuir adsorption isotherms as main input data. The Langmuir isotherm displays an increase of the gas sorption capacity (GSC) with increasing pressure, until a certain maximum is reached at high pressures (over 20 MPa). This behaviour reflects mono-layer adsorption on a surface, where the maximum represents the state of a completely covered surface that can not adsorb any more molecules. In the literature the gas adsorption capacity of coal is generally assumed, next to pressure, to be dependent on temperature and on coal characteristics (Bustin and Clarkson 1998). The effect of these parameters on the GSC of methane is currently a matter of debate.

With increasing temperature the GSC shows a reverse trend (e.g. Bustin and Clarkson 1998; Levy et al. 1997). Both pressure and temperature increase with depth and their opposed effects are superimposed on each other (Kim 1977), resulting in a maximum in GSC at a certain depth.

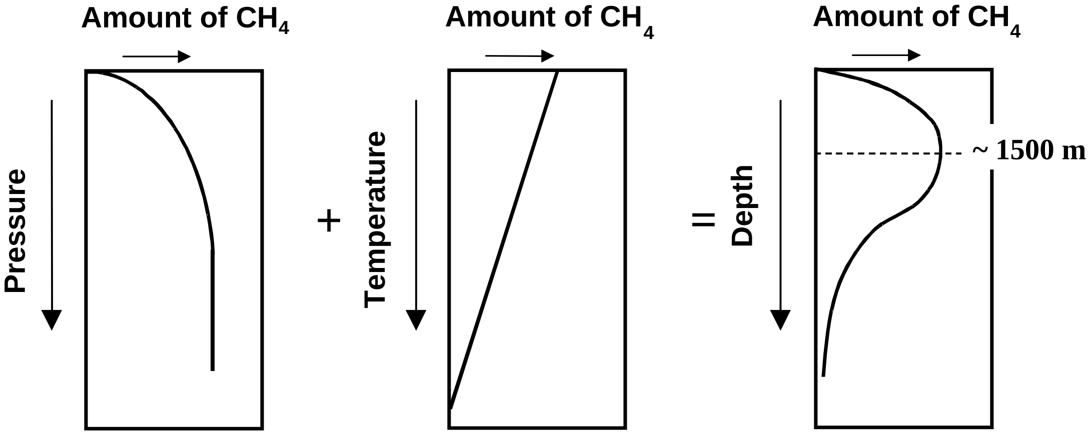


Figure 4-2 Combined effect of pressure and temperature increase with increasing depth on the amount of methane, assuming normal geothermal gradient and hydrostatic pressure.

The coal characteristics that affect the GSC of coal are composition, rank, ash content and moisture content of the coal. These parameters are not independent, which makes it complex to define the impact of the parameters separately. An experimental program is has been executed, on old coal samples from the subsurface of The Netherlands to establish generic relations between the GSC of pure CH_4, pure CO_2, and for mixtures of these gases versus the different variables. These relations need to be determined for areas with a similar geological history within a sedimentary basin. This experimental program is unique because it involves experiments with pressures up to 20 MPa (200 bar).

It must be noted that the gas content, calculated with the Langmuir isotherm, is the maximum amount of gas that can be present in the coal seams under these conditions. The coals can be undersaturated (depleted) with methane due to a degassing in geological history. In this case the methane content is lower than calculated. To correct for a possible degassing in the geological past, burial history graphs of the different areas are constructed, using the paleo hydrostatic pressure (at the time of shallowest burial) for the calculations. The storage potential for CO_2 is independent of methane saturation; therefore the present day hydrostatic pressure are used for calculation of CO_2 amounts.

A generally accepted formula to calculate the Gas-In-Place (GIP) reserves is the following:

$$GIP = A \times h \times \rho_c \times G_c \qquad \text{Equation 4-1}$$

with: GIP = Gas-In-Place (10^6 m^3)
A = area (km^2)
h = cumulative height of coal in the area (m)
ρ_C = density of the coal (tonne/m^3)
G_c = gas content of the coal (m^3/tonne)

More important than the current total amount of gas present, is the amount of CH_4 that can be produced from the coal seams and the amount of CO_2 that can take its place. Therefore this function is extended with the completion and the recovery factor:

$$PGIP = GIP \times C \times R \qquad \text{Equation 4-2}$$

with: PGIP = Producable-Gas-In-Place (10^6 m^3)
C = completion factor (-)
R = recovery factor (-)

The **completion factor** is an estimation of the part of the net cumulative coal thickness within the drilled strata that will contribute to the gas production. The completion factor therefore strongly depends on the thickness of the separate coal seams and the distance between the coal seams. Depending on the application of stimulation techniques and the costs that come with it the completion factor can be increased.

The **recovery factor** is the amount of gas that can be produced from a contributing coal seam. In conventional CBM production this depends strongly on the pressure drop that can be realised by pumping of large volumes of water. The production of CBM by conventional methods is often inefficient: normally only about 20% to 60% of original GIP can be recovered. With the process of ECBM with gas injection the recovery can be increased, theoretically up to 100 % (Stevens and Pekot 1999). In a reasonable timeframe of 20 years, about 90 % of this Producable Gas in Place can really be produced. The progress in recovery over time will be dealt with in §5.1.

4.2.3 Monte Carlo calculations

It is very obvious that there are many uncertainties in the values of the parameters used. Monte Carlo simulation analysis is applied in this study. This analysis allows, in a probabilistic manner, the prediction of the expected average PGIP and the expected amount of CO_2 to be stored and their distribution of reserves. The resulting uncertainty quantification of producible gas content and storable CO_2 can be used for economic studies. Triangular distributions are used (with a minimum, median, and maximum) for G_{LC}, P, P_{LC}, h, ρ_C, C, R, ER. The values for the variables vary per area. All areas and fault bounded blocks, as defined in the area selection, are evaluated using Monte Carlo simulation analysis.

The results are presented in a probability curve (Figure 4-3). Qualitative terms are used to indicate the degree of certainty: proved (a certainty of 90%), probable (50%) and possible reserves (10%).

Table 4-1 shows CBM reserves for the researched areas. The total producible gas content is the maximum amount of CBM that can be produced using the methods that will be described in this chapter.

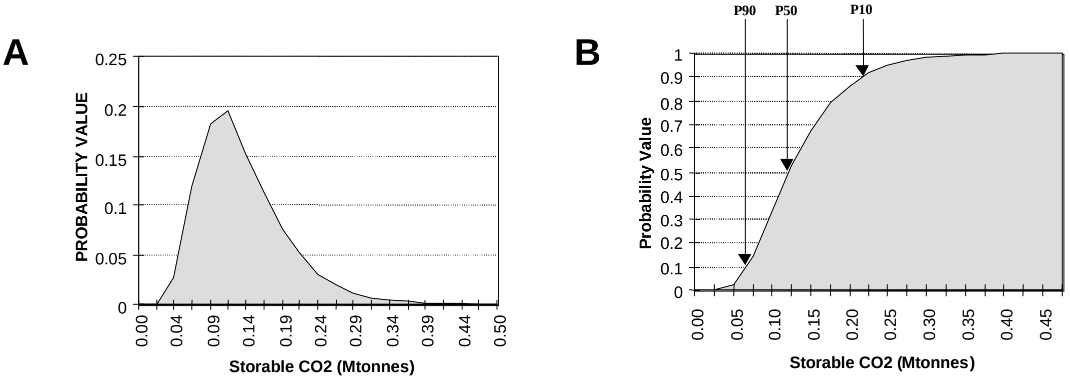


Figure 4-3. Results of the Monte Carlo Analysis of the 600-1000m interval of Block 4 in the Zuid Limburg area. A) probability curve and B) cumulative probability curve of the methane reserves. The reserve estimations indicated at P90, P50 and P10 give respectively an increasing uncertainty in the reserve estimation of 10, 50, and 90%.

The Producible Gas in Place of the four areas up to 1500 m depth, ranges from $9{\cdot}10^9$ m^3 or 0.31 EJ (proven) to $109{\cdot}10^9$ m^3 or 3.9 EJ (possible), or, up to 2000 m from $60{\cdot}10^9$ m^3 (2.2 EJ) to $518{\cdot}10^9$ m^3 (19 EJ). For comparison, the known reserve of natural gas in the Netherlands was $2{\cdot}10^{12}$ m^3 (72 EJ) in 1994 (Ministerie van Economische Zaken 1995). It can be concluded that the potentially accessible CBM reserves of the Netherlands have a high potential. Details for the sectors Peel 3 and Achterhoek 2 are given because these sectors have a combination of high average CBM reserve and large surface. A more detailed table can be found in Annex D.

The actual Gas in Place and theoretical storable CO_2 are much higher: GIP ranges to maximally 60 EJ, the corresponding storable CO_2 would be 8 Gtonne. These amounts, however, are not producible with current available exploitation techniques.

Table 4-1. Producible Gas in Place for the Peel, Zuid Limburg, Achterhoek and Zeeland area, plus details for sector 2 in the Achterhoek and sector 3 in the Peel. Note that the volumes for the areas are per km^2, while the energy reserves and total volumes are for the entire surface.

			Proved Reserve		Probable Reserve		Possible Reserve	
Area	**Surface(km^2)**	**Interval (m)**	**(Mm^3/km^2)**	**(EJ)**	**(Mm^3/km^2)**	**(EJ)**	**(Mm^3/km^2)**	**(EJ)**
Peel	536	<1500	8.4	0.16	21	0.40	43.8	0.84
Zuid Limburg	48.4	<1500	25.6	0.04	53	0.09	102	0.18
Achterhoek	3796	<1500	0.80	0.11	5.6	0.76	21.1	2.88
		1500-2000	1.80	0.24	12.2	1.66	46.4	6.30
Zeeland	2346	1500-2000	19.1	1.60	48.0	4.03	99.2	8.34
Achterhoek 2	718	<1500	3.61	0.09	25.5	0.66	96.1	2.47
Peel 3	152	<1500	11.5	0.06	29.6	0.16	62.4	0.34
			Proved Reserve		**Probable Reserve**		**Possible Reserve**	
			(Gm^3)	**(EJ)**	**(Gm^3)**	**(EJ)**	**(Gm^3)**	**(EJ)**
Areas Total		<2000	60.3	2.16	194	6.95	518	18.5

The Zuid Limburg area has the highest estimated (producible) methane contents per km^2. Considering the total available surface per area, the Achterhoek 2 area has the highest estimated potential for producible methane. This implies that Zuid Limburg is probably the best location for a test site, whereas the Achterhoek probably has more potential for large scale CO_2 sequestration. The Peel 3 area probably is a good intermediate, with fairly high methane content and an intermediate sized area.

The amount of storable CO_2 for the investigated areas is summarised in Table 4-2, it is calculated by multiplying the Producible Gas in Place with the CO_2/CH_4 exchange ratio.

Table 4-2. Amount of Storable CO2 for the Peel, Zuid Limburg, Achterhoek and Zeeland area.

Area	Interval (m)	**Proved Storable (Mtonne)**	**Probable Storable (Mtonne)**	**Possible Storable (Mtonne)**
Peel	<1500	31	76	156
Zuid Limburg	<1500	6	13	25
Achterhoek	<1500	17	116	431
	1500-2000	36	249	938
Zeeland	1500-2000	214	561	1184
Areas Total	<2000	304	1015	2734

4.3 CO_2 storage and production of ECBM

4.3.1 Theory

Carbon dioxide adsorbs more easily to coal than methane, roughly twice as much CO_2 than CH_4. This is illustrated by the sorption isotherms in Figure 4-4. At partial pressures greater than the desorption pressure, no desorption occurs (see Annex D, Figure D-2). Under this pressure equilibrium exists, based on the adsorbed gas concentration in the coal matrix and the free gas pressure in a cleat.

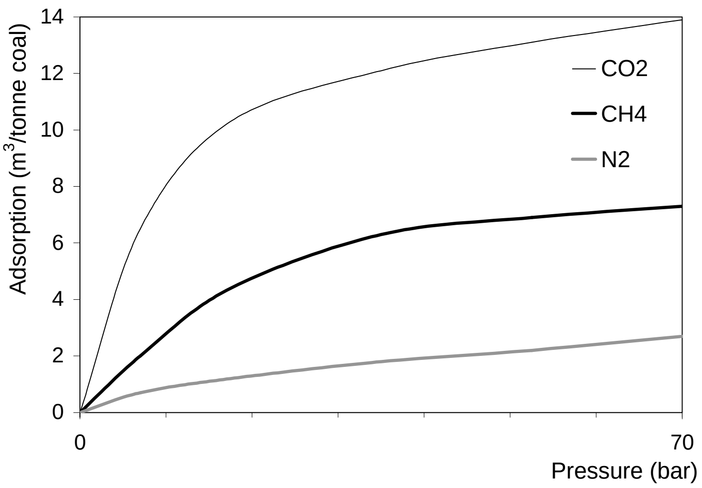


Figure 4-4. Sorption isotherms at T = 294 K.

When all the desorbed methane is being carried away, theoretically all methane originally adsorbed on the coal surface can be recovered. However, its desorption rate will decline at a lower CH_4 content and as not every pore is reached by the CO_2 (100 % sweep efficiency), the methane desorption will not fully reach its maximum. The fraction actually desorbed and replaced is called the recovery factor.

Given that the sorption isotherm of CO_2 is about twice as high as that of CH_4, the coal seam surface can sequester approximately two molecules CO_2 for one CH_4. After stopping the methane production, even more CO_2 can be put into the coal seam, due to channelling of CO_2 through faults and other high-permeability pathways. Apart from this, the coal seam could originally have been methane-undersaturated, which also increases the CO_2/CBM ratio (IEA Greenhouse 1998). The department of Applied Earth Sciences at the Delft University of Technology showed on basis of laboratory tests that, depending on the pressure in the coal seam, two or more molecules of CO_2 replace one molecule of CH_4 and the present water. This has also been shown by experiments at Aachen University of Technology (Krooss et al. 2000).

4.3.2 Major results of the laboratory experiments

In the foregoing 3 years at the sections of Petroleum Engineering and Petrophysics of Delft University of Technology, various methane / carbon dioxide replacement experiments have been completed, to investigate the production and storage behaviour of coals under in-situ conditions. The depth of investigation that could be simulated under laboratory conditions was about 700 m. The results of the experiments provide information on the in-situ permeability of the coal, the CH_4 and CO_2 capacity of dry and water saturated coal and the fracture dimensions of two coal types. Since one experiment normally takes at least two months only the extreme situations, as can be expected in the sub-surface at the mentioned depth, are considered. Methane saturated wet and dry coals, are flushed with gas phase, liquid phase or super critical carbon dioxide. The results of these tests (Figure 4-5) explain the behaviour of coal, its fracture system and the present fluids/gases in a transition zone between the original CH_4 bearing seam and the flushed CO_2-rich area. An abstract of this work can be found in appendix F and the technical report (Bertheux et al. 2000); the main results and findings are described below.

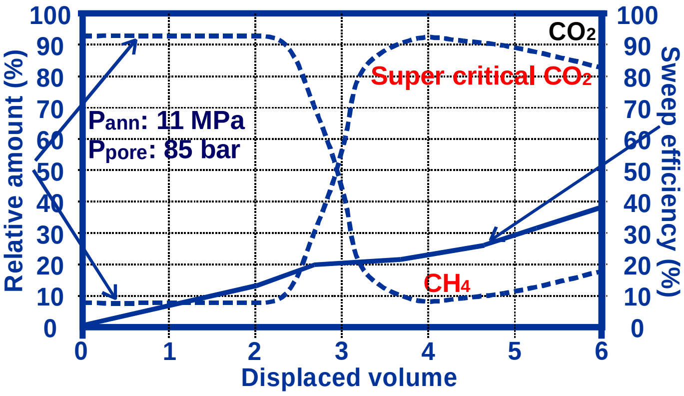


Figure 4-5. Result of a CH4-CO2 replacement experiment in a water saturated coal; example

Coal cleat permeability

The fracture pattern, or cleat system of a coal is the major transport system of the fluids and gases. At an increase of overburden load the cleats are rapidly closed. When the pore pressure is increased, the fractures are reopened and permeability improves. The cleat patterns of the studied coals are quantified on their length, orientation and distances by image analysis. The results are used in preliminary modelling studies and will be used in upcoming reservoir studies at seam/cleat level. Two types of cleat systems have been recognised (Annex F, image analysis); a rectangular pattern and a rhomboidal pattern. The rectangular pattern gives a more rapidly more tight closure and lower stress dependent permeabilities (up to 0.1 mD). The best results are achieved when the differential pressure (lithostatic stress minus pore fluid pressure) is less than 20 bar. In that case, on the whole, the permeability will be higher than about 1 mD and the coal can be compared with a fractured natural tight gas reservoir. As a result, injection of CO_2 gives an increase of the fracture permeability, which can be used at the CO_2 front to improve the replacement of methane and water by carbon dioxide and to increase the sweep efficiency.

CO_2 replacement experiments

The first round of laboratory experiments are extensively described in appendix F and in the TU Delft - Novem technical reports of Bertheux et al. (2000), de Haan (1999), Wolf et al. (1999a). Table 4-3 gives the sweep efficiencies of gaseous/liquid/supercritical CO_2 in wet and dry coal.

Table 4-3. Sweep efficiency results at 90 % CO_2-production.

	Methane sweep efficiency ratio (-)	**Displaced volume (mole/mole)**	**Running time (sec)**
A: Dry coal, CO_2 gas	52	1.65	$7.5 \cdot 10^5$
B: Water wet coal, CO_2 gas	26	0.55	$1.05 \cdot 10^5$
C: Dry coal, CO_2 liquid	48	4.9	$2.07 \cdot 10^6$
D: Water wet coal, CO_2 liquid	30	3.0	$8.6 \cdot 10^5$
E: Water wet coal, CO_2 super critical*	> 40*	3.82	$1.9 \cdot 10^6$

*After reaching a maximum of 92 vol.% of CO_2, the methane content slowly increased again after a DV of ~ 4

The main results of these tests are:

- **For water free coals:** CH_4/CO_2-production patterns from dry coal with the injection of gas, liquid or super critical CO_2 look very promising. The displacement volumes show that a transition zone from methane saturated to carbon dioxide saturated coal will be small, with a high sweep efficiency for CH_4-CO_2 replacements. So, on field scale especially dry coals swiftly exchange CH_4 for CO_2 and a high sweep efficiency appears to be easily created when the water is pumped away.
- **For water saturated coals:** In all water-wet systems, the major part of the water is rapidly removed from the cleat system. However, water seriously obstructs the CO_2 in reaching the matrix pores. Under water saturated conditions several times the original coal cleat/pore volume is needed to replace just a part of the methane for CO_2. The initial sweep efficiencies probably will be low. This translated to field scale, indicates that the transition zone from a CH_4-saturated to a CO_2-saturated coal most likely will be large (tens of meters).
- **Water saturated coals and supercritical CO_2:** The use of super critical CO_2 in wet coals shows satisfactory results. Despite a fast but very small breakthrough of CO_2, for a long time, methane is removed at high rates. After maximum CO_2 breakthrough again the production of methane is slowly recovering. This experiment can be compared with the results on the dry coals. Translated to field scale the experiment shows that, despite the creation of a relatively large transition zone, the drying effect of super critical CO_2 results in a higher sweep efficiency of methane and water and an improved CO_2-storage capacity.

Remarks with regard to the results

These preliminary laboratory results prove at laboratory scale, that the ECBM process is feasible under extreme conditions up to about 700 m depth. Tests that simulate the situation at greater depths (as desired up to at least 1500 meters) have not been performed so far. Further, dry or fully water saturated coals are usually not present, water will be saline and coal habitually contains minor amounts of SO_2, N_2 and/or CO_2, which might affect the replacement processes as mentioned before. In addition, the injection of flue gas instead of CO_2 could also be an option and should be investigated. Further the study concentrated on the processes in the coal seam, but the integrity (sealing capacity) of the coal roof rock should also be an issue.

4.3.3 ECBM production

For actual exploitation of CBM reserves, CO_2 injection production wells are placed and water is pumped out of the coal seam, which will reduce the reservoir pressure (see §4.3.5). The methane adsorbed on the coal matrix desorbs, and diffuses to the cleats, then flows with the water to the production well. After a period of time injection wells are drilled. The injection of CO_2 allows a further decrease of the CH_4 partial pressure, maintaining the reservoir pressure, while at the same time the methane is driven out to the production well.

Different set-ups are possible for the configuration of injection and production wells. All set-ups are repeatable in the horizontal plane. The 7 spot (6 injection / 1 production) has a honeycomb structure, which is most suitable for fast production of methane. The triangular 4 spot (3 injection / 1 production) is relatively inexpensive but more vulnerable when one of the wells is less successful. A 5 spot cubical set-up with 4 injection and 1 production well, as shown in Figure 4-6, seems the most suitable option and is used for further analyses in this report.

When considering a large ECBM field, each injection well is surrounded by production wells and vice versa (the cubicle set-up is an ideal situation). This set-up is also used in a model developed by TUD Applied Earth Sciences to simulate ECBM production over time, which is used in this study for predicting costs and yields of ECBM. The actual arrangement of wells on the field depends mainly on the structure of the underground. In general, because of decreasing well pressure, production of water and well stimulation, more production wells than injection wells are needed.

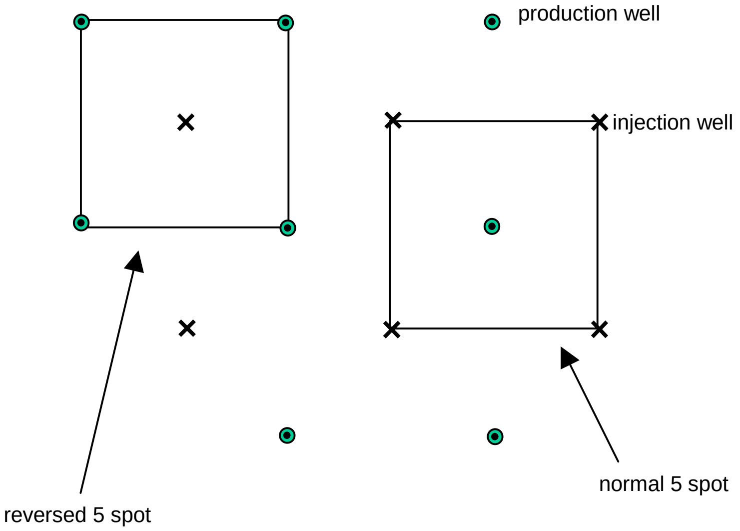


Figure 4-6. Cubicle set-up for production and injection wells.

4.3.4 Modelling and simulations

Sorption modelling at cleat scale and simulations at field scale are done at Technical Geoscience of Delft University. The modelling work at cleat level is described in appendix F. These results are matched with the laboratory experiments, and the outcomes on permeability, sorption and diffusion behaviour are used in a compositional simulator, STARS^{TM}, a multiphase reservoir simulator that incorporates a multicomponent gas option. The model can forecast ECBM production rates over time based on characterisation of the coal seam and set-up of production and injection wells. A more detailed description of this model is given in Annex G. For simulation of the CH_4 and CO_2 sorption on coal, the model makes use of the immobile oil concept. The coal surface is modelled as if it was covered with a thin oil layer in which initially methane is dissolved. Here, for the migration of methane and carbon dioxide, the sorption and diffusion data of the micro modelling work were used.

Typical values characterising the coal were obtained from coal bed methane tests in Peer, Belgium, the Black Warrior basin, USA, and laboratory studies at Delft University of Technology. The conditions in those tests are reasonably representative for ECBM in the Netherlands. These key values and variables used for the simulations on drilling and production are given in Table 4-4.

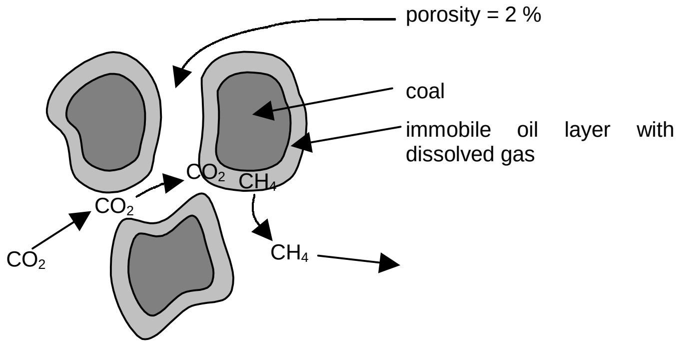


Figure 4-7. The immobile oil concept of the Delft ECBM model.

Table 4-4. Typical values in ECBM simulation.

Coal seam	
Average coal seam thickness (completed)	7.62 m
Total gas content	10 m^3/tonne
Porosity	2 %
Permeability	0.1-2.0 mD
Well	
Well Spacing	400×400 m^2 – 1000×1000 m^2
Skin stimulation	-3 – 0
In seam drilling	0 – 444 m
Well radius: casing through coal	5 ½ inch

The chosen coal seam thickness is the cumulative seam thickness of all the exploitable seams over 500 to 1500 meter depth. It was estimated that of all the coal in the depth range considered, 50 % can be exploited. Therefore a completion factor of 0.5 is applied. The total gas content of 10 m^3/tonne is a realistic value. In practice the thickness of the exploitable coal and its gas content will differ from area to area and application of a correction factor is necessary to make the Producible Gas in Place value of the model consistent with the value of the considered area (see §5.1).

The permeability in all directions (x, y, z) is taken the same. In reality this permeability depends very much on the coal type, local cleat structure and lateral continuity. The thickness of the seam influences the permeability in vertical direction. The permeability and porosity values used are relatively conservative.

Inseam drilling increases the contact area of the well with the coal seam. Depending on the exploited area, there is an optimal horizontal length of inseam drilling beyond which the costs of additional drilling do not offset additional revenues. When the well spacing is so small that inseam drilling does not increase the revenues, the well is stimulated by creating a large contact surface around the well. This is called skin removal.

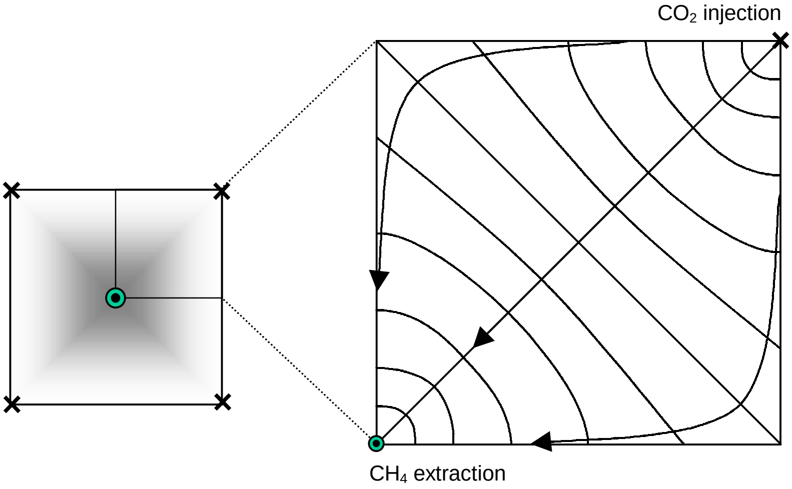


Figure 4-8. One quarter of the production quadrant. Advancing front of CO_2.

In the STARS model one quarter of the quadrant of a cubicle set-up of wells is simulated (see Figure 4-8). This quarter is the mirror image of the three other quarters. If the quadrant lays amidst other quadrants, there is no net gas diffusion through the sides of the quarter as the adjacent quarters must have the same geometry in diffusion.

The dimensions of the cubicles can be chosen varied. Wolf et al. (1999a) considered well spacings of 400×400, 570×570 and 800×800 m^2 in their study. For the present study also well spacing resulting in squares of 1 km^2 are included. The highest recovery of methane as a percentage of the initial gas content of the coal (called Gas in Place) is achieved with the smallest well spacing of 400×400 m^2. A consequence of this small spacing is that after 4 to 8 years the methane production of this set-up declines quickly. ECBM production from the 800×800 m^2 set-up however still peaks just after 12 years (Figure 4-9).

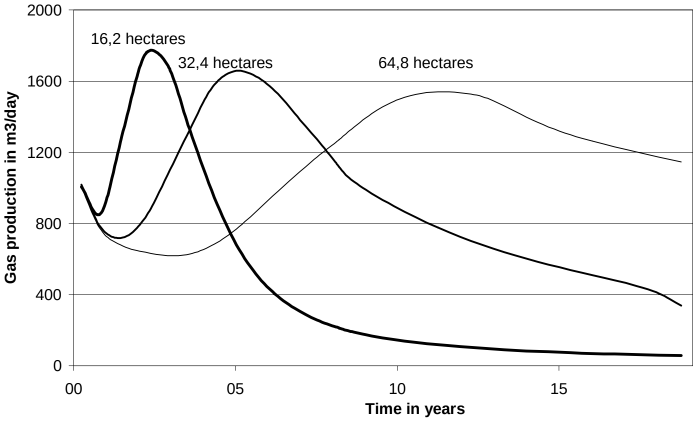


Figure 4-9. Primary methane production (CBM by groundwater pumping) rates as a function of time for different well spacings over a period of 20 years.

Figure 4-10 shows that the total methane production from the 800×800 m^2 field after 20 years of production is 2.3 times the production from a 400×400 m^2 field, where the initial gas in place for the bigger spacing was 4 times more than the initial gas for the smaller spacing. With a larger spacing it takes longer to produce the same amount of ECBM and the revenues are postponed. On the other hand when the well spacing is small much more wells are needed, which adds to the costs of ECBM. One

800×800 m^2 cubicle contains 4 cubicles of 400×400 m^2, the former has 5 wells and the latter 13. In a large area 4 times the number of wells are needed for the 400×400 m^2 well spacing compared to the 800×800 m^2 spacing. There is therefore a trade-off between slower gas production (and delay in revenues) and lower investment costs for wells. This will be analysed further in Chapter 5.

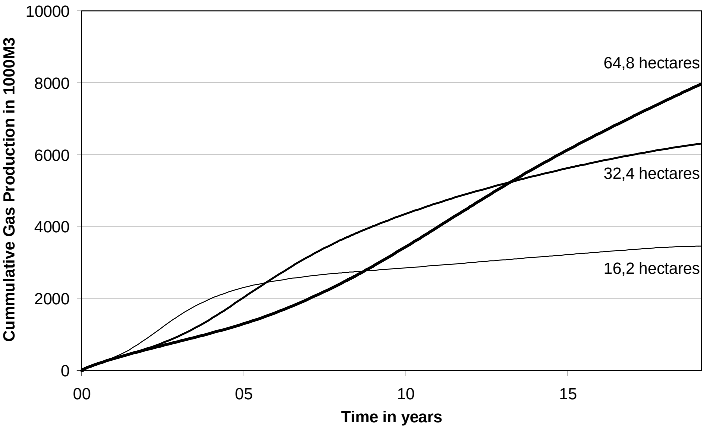


Figure 4-10. Cumulative enhanced methane production for different well spacing over 20 years.

4.3.5 Production technology

Drilling

Figure 4-11 schematically shows an example of an injection and production well system. First, the production wells are drilled; this process of completion and operation is described by Wolf et al. (1999a). Usually a multitude of smaller layer is accessed by the well pipes, adding up to a total coal layer thickness over a certain depth range. This depth range lays between about 500 to 1500 m for Dutch conditions because outside this range the amount of recoverable CBM rapidly decreases (see Annex D).

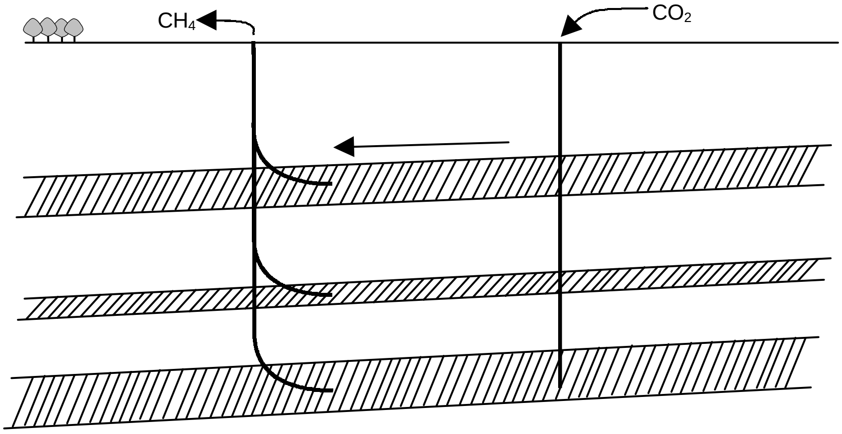


Figure 4-11. The production well with in-seam drilling (left) and the injection well.

Gas production is initiated by pumping off large volumes of formation water to lower reservoir pressure and allow methane desorption from the coal. Perforating the casing should allow both maximum stimulation and cleanup, as well as maximum production. Especially in larger production fields, the contact surface of the well with the coal seam has to be increased further by means of in-seam drilling. This is shown by the horizontal lines of the CH_4 wells: part of the coal seam is horizontally entered. Inseam drilling is a very effective way of stimulating the coal seam. As the length of a horizontal well is increased, its contact with the reservoir increases. Depending on the drainage area, there is an optimal horizontal length of inseam drilling, beyond which the additional drilling and maintenance costs do not offset additional revenues (Barzandji et al. 2000).

Instead of drilling straight vertical wells, modern techniques provide the possibility of drilling several wells commencing at one surface location. With deviated holes or drilling at an angle, as shown in Figure 4-12, a whole quadrant with production and injection wells can be addressed from one spot.

CO_2 injection

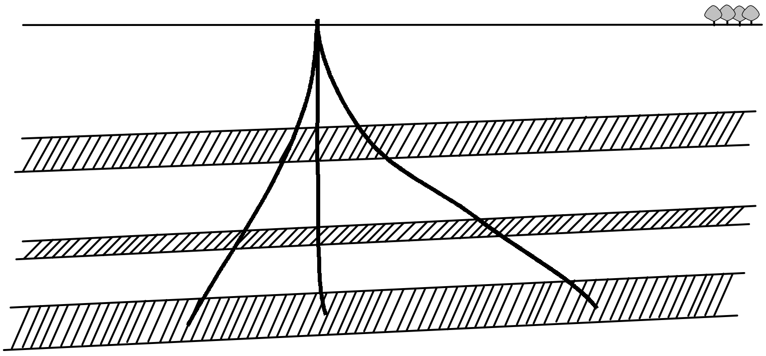


Figure 4-12. Deviated drilling.

For the injection of CO_2, additional pressurisation above the 8000 kPa transport pressure may be required if the reservoir shows a high pressure gradient. In this case compressors have to be installed at the storage site. The required injection pressure in the pit is a result of the delivery pressure at the wellhead plus the weight of the CO_2 column (Hendriks 1994). The cases which are investigated are set at a bottom hole pressure of about 4000 kPa. The injection well can be drilled at the same time as the production well, which has the advantage of quick ECBM revenues and CO_2 storage. Another option is to delay the drilling and thus the investment of the injection well until the time the production wells undergo primary recovery beyond the peak CH_4 production rate. Both cases are included in the economic analysis.

Improving gas quality

Gas and water with some coal fines are produced simultaneously and have to be separated. The water can not be disposed off directly and has to be cleaned. Crude oil has been reported to be present in some coalbed methane wells. Free oil may be removed by gravity separation at the wellhead or by a skim tank before further water treatment or discharge. Collected oil is typically treated off- site (Davidson et al. 1995). In the San Juan Fairway, the natural CO_2 concentration of produced coal seam gas is 6 to 12 %, hence CO_2 separation is necessary for some applications (Advanced Resources International Inc. 1998). The quality of Dutch CBM is not known.

The produced gas from the water/liquid separator should go through a filter to prevent coal fines (small particles) from giving downstream problems in the dehydrator, compressor and flow meter. Dehydration of CBM is based on conventional glycol systems developed for gas wells. Glycol adsorption of water vapour works best at low temperature and high operating pressure (Barzandji et al. 2000).

Water production and disposal

Coal gas wells usually produce large volumes of water, initially 1.5 to 15 m^3/d. Deeper coal seams, which are usually less permeable, generally produce smaller quantities of water compared with shallower seams. The produced water volumes decrease with time. Due to the high gas to liquid ratio, vertical separators work best, and handle large capacities.

The coal water contains dissolved salts, predominantly sodium chloride and bicarbonate. High concentrations of total dissolved solids (TDS), are considered a problem because they can cause undesirable effects on aquatic organisms and sweet water resources in addition to scale forming in the installation. In some cases, suspended solids may pose a problem. Other possible pollutants include mineral oil, which is present in the coal water of some areas. Just as the quantity of water pumped from the coal seam varies, so does its quality, depending on the geology associated with the coal beds, aquifers, and region. CBM water generally has much lower concentrations of dissolved organic compounds compared with water from natural gas wells. These differences in composition can strongly affect the water treatment options for the two types of produced water (Davidson et al. 1995).

The two most common solutions of dealing with the coalbed water are reinjection and surface discharge. In the San Juan Basin, reinjection is broadly applied; many disposal wells make use of depleted gas reservoirs that have fairly good porosity and permeability. But as their storage capacities will ultimately not be sufficient, other disposal methods are developed. In the Black Warrior Basin most of the formations have low permeability and surface discharge is a more cost-effective option in this case.

The storage capacity of reinjection wells exceeds the produced water volumes (Wolf et al. 1999a). Filtration of the produced water is usually required to prevent damage to a disposal well. The wells need to be cased and cemented to prevent the loss of injected fluids into unapproved zones, such as underground sources of drinking water. The injection pressure is an important parameter. However, fracturing within a formation during injection could allow injected water to communicate with other zones, including freshwater aquifers (Davidson et al. 1995). This aspect deserves further attention.

In case of discharge to surface water, the water quality must meet stringent environmental standards. Coalbed water can have a high salinity and contains various inorganic ions and organic traces. Therefore, direct discharge of coalbed water is not possible. The waste water treatment required depends on the geography and climate of a region that determine the capacity of water courses to accept discharges, and the regulations and permits that are enforced.

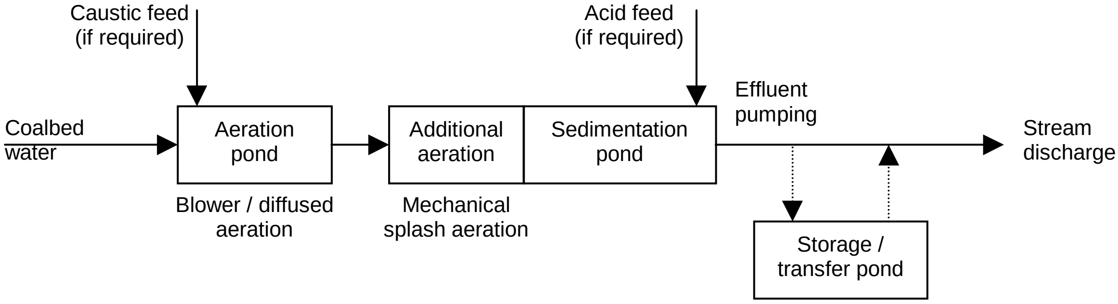


Figure 4-13. Aeration/sedimentation system for treating water produced during CBM (Davidson et al. 1995).

Treatment of the coalbed water before discharge typically follows the general scheme shown in Figure 4-13. Sedimentation and treatment ponds typically receive water from multiple wells. By means of aeration some of the soluble ions are oxidised and precipitated. Adding caustic or acid feed might be required for flocking salts. Bacteria and algae can breakdown complex organic substances into soluble matter and absorb the material as a source of energy and nutrition. In this study the costs for water treatment are taken 15 €/m^3, this is at the high end of values given by (Davidson et al. 1995).

Other processes for water disposal, like direct land application and surface evaporation are suggested by (Davidson et al. 1995), but these methods are not suitable for the Netherlands.

5 Economics

This chapter gives an economic analysis of ECBM. First, a set of 7 scenarios will be assessed. The CO_2 storage costs for producing competitive gas production will be calculated and compared with costs of other CO_2 storage options. Second, the influence of costs parameters and ECBM reserves will be investigated in a sensitivity analysis. Third, ECBM scenarios producing power or hydrogen on top of the field will be evaluated.

5.1 The price of ECBM gas

7 Scenarios for ECBM production have been evaluated; Table 5-1 gives the characteristics of each one. All scenarios use a form of well stimulation to keep the production and injection time within reasonable limits: Inseam drilling and/or negative skin. For the larger well spacing scenarios, the length of the inseam drilling has been varied from moderate to extreme. Larger inseam drilling is more expensive but also gives higher revenues in shorter time.

The smaller well spacings have the advantage of quicker CBM production and earlier revenues, but as much more wells per square kilometre are needed for the exploitation, these small spacing also result in high investment costs. The injection period is varied from direct injection to injection after the peak CBM production. The total injection volume sums up to 2.5 times the extracted CBM.

Table 5-1. Researched ECBM scenarios.

Scenario	**Field dimensions (m^2)**	**Inseam (m)**	**Skin**	**Exchange ratio (mole CO_2 / mole CH4)**	**CO2 injection Period** (years)	**CH4 production period** (years)
A	400x400		-3	1.3	11 until 25	1 until 32
B	600x600	27	0	1.9	14 until 41	1 until 44
C	800x800	107	0	1.4	11 until 25	1 until 30
D	800x800	330	-3	2.7	1 until 27	1 until 14
E	1000x1000	222	0	1.7	11 until 38	1 until 38
F	1000x1000	410	-3	2.6	1 until 42	1 until 23
G	1000x1000	444	0	1.4	16 until 60	1 until 42

Based on costs and revenues of ECBM production the price of the produced gas is calculated. Because of the rather complex dynamic nature of ECBM systems over time, the net present value – NPV method is used for the economic analysis. The investment for drilling the production well is done before the first production year. If CO_2 injection starts at the same time as CBM production the injection well is drilled simultaneously. Otherwise the investment for injection wells can be postponed. Furthermore various cost factors vary over the years, depending on produced volumes. Those factors are incorporated using NPV as well.

All parameters used are shown in Table 5-2. The costs accompanied by drilling are discussed in Annex I. The costs of drilling are very variable and depend on the used technology, the location, economy of scale and year of realisation. For a 1500 m deep well the cost can range between 300 and 900k€. In the Netherlands the costs for onshore drilling are expected to be relatively high compared to other parts of the world, due to local legislation, equipment prices and, on the short term, the R&D nature of ECBM and will therefore most likely be between 600 and 900 k€.

Barzandji (2000) writes that the investment for a production well is 750 k€ plus 1.5 k€ for every meter inseam drilling. An injection well, which has a simpler construction, costs about 430 k€. In this study the investment costs are taken 2/3 of the values that Barzandji gives, so that a production well with extreme inseam drilling costs about 1 M€. The investment for the injection well is in the low cost range. O&M costs are 1 % of the basic investment (thus without inseam drilling costs) for the production well and 4 % of the total investment of the production well. Costs for gas gathering treatment and compression before the CBM gas can be injected in the grid are $5.4 \cdot 10^{-3}$ €/m^3. Costs for water treatment are taken 15 €/m3 as has been discussed in §4.3.5.

For all scenarios the cost of CO_2 at the wellhead is set at 15 €/tonne, which is a realistic price for 0.1 to 3.4 Mtonne/year CO_2 captured at an industrial source and transported to the Peel, Zuid Limburg or Zeeland area (see Chapter 2 & 3). Transport to the Achterhoek is more costly for small amounts;

therefore 0.1 Mtonne/year costs 55 €/tonne at the wellhead. The price of CO_2 is varied in order to study the influence of a bonus for CO_2 sequestration.

Table 5-2. Parameters for economic analysis.

Production well	
Basic investment	0.5 M€ two years before first production
Extra investment for inseam drilling	1.1 k€/m
O&M	1 % of basic investment
Injection well	
Total investment	0.3 M€ one year before first injection
O&M	4 % of total investment
Volume dependent	
Costs of CO_2 at the wellhead	15 €/tonne
Gas gathering, treatment & compression before grid	5.4·10-3 €/m3
Water cleaning & disposal	15 €/m3
Interest rate	10 %

As an example Figure 5-1 shows the result of the ECBM modelling done with the STARS model for scenario F. This scenario has a large well spacing which reduces the investment costs for the wells. Furthermore CO_2 injection is started directly in the first year which results in CO_2 sequestration on the short term. The production of CBM is stopped after 23 years when the CO_2 breaks through at the production well and dilutes the CH_4. At this point about 90 % of the Producible Gas in Place is recovered. Injection continues for 15 more years after CBM production is stopped in order to fill up the coal seam with CO_2. Eventually 2.6 molecules of carbon dioxide are sequestered for each methane molecule recovered. From this graph, the annual volumes of CBM, water and CO_2 injected are derived. The technical lifetime of wells and equipment is estimated to last for the duration of the project.

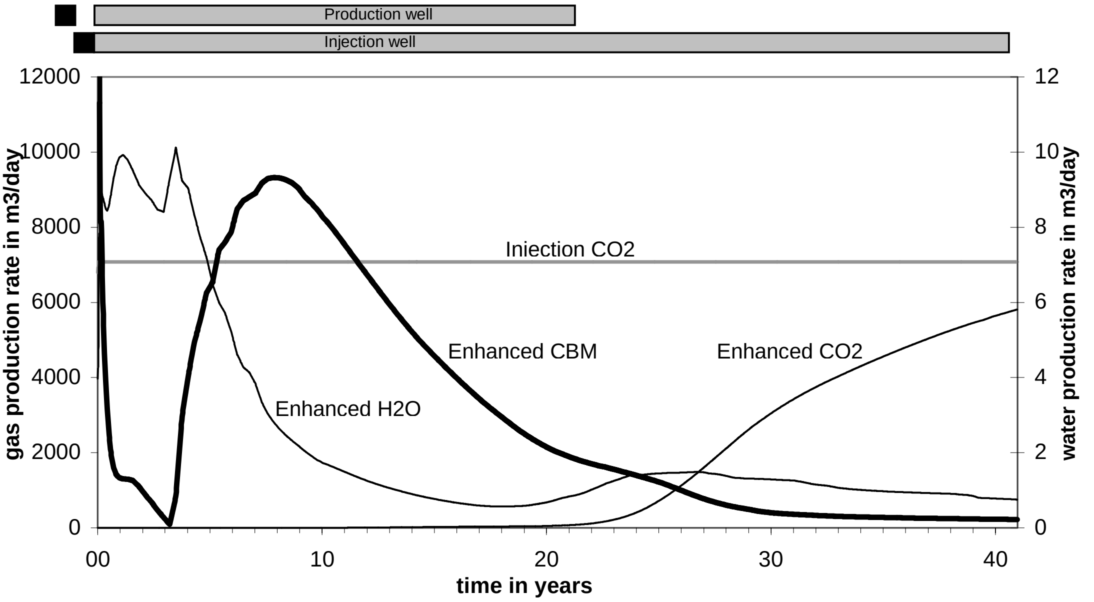


Figure 5-1. Gas and water flows for scenario F (1000×1000 m^2, 410 m inseam, skin –3, CO_2 injection from first year). Indicated are also the moment of investment,■ , and the period of operation,□. Graphs for some other researched scenarios can be found in Annex G.

The assumed Producible Gas in Place in the model is 45.0 Mm^3/km^2. The Peel 3 area has 29.6 Mm^3/km^2 Producible Gas in Place (probable reserve). In order to make the model consistent with the Peel 3 area, all the flow rates from the simulation are corrected with a factor 0.66. The evaluated coal seam has a surface of 2x4 km^2, this is a representative dimension of real coal seams. Eight production quadrants with a 1000x1000 m^2 spacing fit in this area: 15 production wells and 8 injection wells.

The total Peel 3 area measures 150 km^2, With scenario F annually 508 ktonne CO_2 could be sequestered over a period of 40 years. The average annual CBM production is about 5 PJ with a peak production around the eighth year of about 12 PJ.

This scenario results in CBM production costs of 8.7 €/GJ. Figure 5-2 presents the breakdown of the gas price into investment and maintenance costs for the wells; costs for gas compression and make up, and water disposal; and costs for the injected CO_2. The investment cost for the production wells makes the biggest contribution to the gas price.

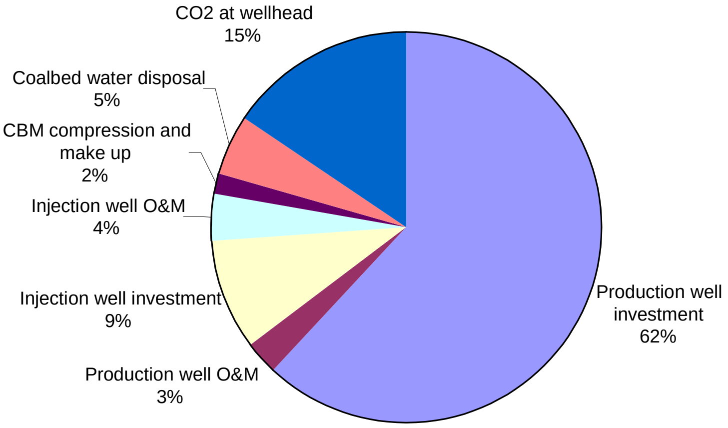


Figure 5-2. Breakdown of CBM price for the scenario F (1000×1000 m^2, 410 m inseam, skin –3, CO_2 injection from first year). CO_2 costs are 15 €/tonne (no bonus),

Results for all the scenarios are given in Table 5-3. ECBM produced with small well spacings is significantly more expensive than ECBM produced at 800×800 or 1000×1000 m^2 fields. The earlier revenues of fields with a small spacing do not compensate for the higher investment costs per square kilometre. With no revenues from CO_2 sequestration, direct injection of CO_2 is uneconomical. However when a bonus for CO_2 sequestration is applied, ECBM production costs for direct injection scenarios drop sharply. From Figure 5-3, where the influence of the CO_2 price on the CBM price is shown graphically, it can be seen that the choice for one scenario or the other depends clearly on the bonus given for CO_2 sequestration.

Table 5-3. ECBM production costs in **€/GJ** for all scenarios considered. Base case: parameters from Table 5-2 are used.

Scenario	**Characteristics**	**Bonus for CO2 sequestration**	
		0 €/tonne CO2	**45 €/tonneCO2**
A	400x400 m2, skin stimulation, late injection	16.4	14.7
B	600x600 m2, 27m inseam, late injection	15.3	13.4
C	800x800 m2, 107 m inseam, late injection	7.9	6.0
D	800x800 m2, 330 m inseam and skin, direct injection	9.3	4.8
E	1000x1000 m2, 220 m inseam, late injection	6.5	4.9
F	1000x1000 m2, 410 m inseam and skin, direct injection	8.7	4.6
G	1000x1000 m2, 444 m inseam, late injection	8.5	7.9

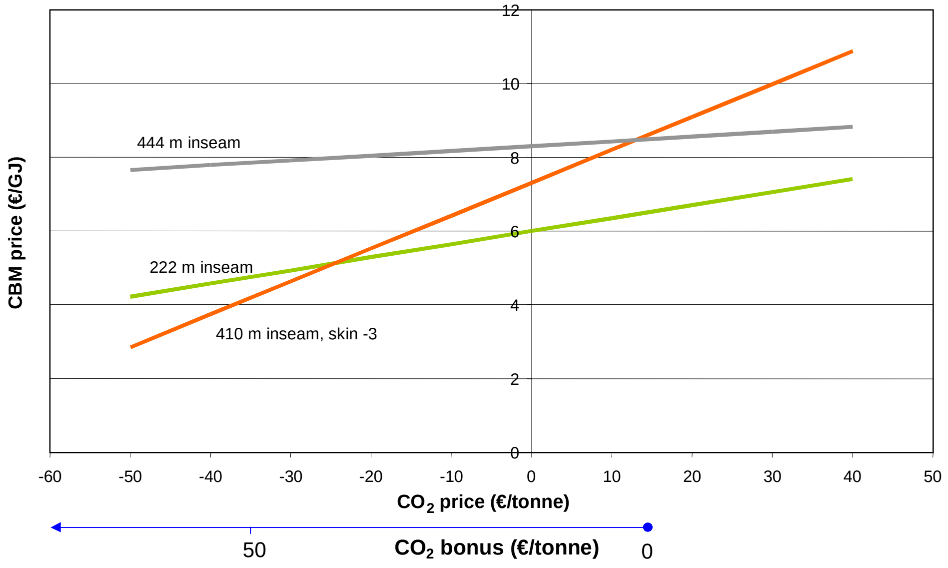


Figure 5-3. Influence of CO_2 price on CBM price for 1000×1000 m^2 scenarios E, F and G.

5.2 Sensitivity analysis

The price of natural gas amounts currently between 2.1 and 2.6 €/GJ. On the longer term the gas price is expected to increase slightly to 2.5 to 3.2 €/GJ (USDOE/EIA 2000). The costs of ECBM should be as low as the market price in order to be competitive.

ECBM production costs with sensitivity to variation of the investment costs, the CO_2 price, and the interest rate, are given in Table 5-4. A CO_2 price of –30 € means a subsidy of 45 € per tonne sequestrated.

Table 5-4. ECBM production costs in €/GJ for all scenarios considered, and sensitivity to investment costs, CO_2 price, and interest rate.

Scenario	**Base case**	**Investment costs**		**CO_2 price**		**Interest rate**	
		50 %	**150 %**	**-30 €/tonne**	**30 €/tonne**	**5%**	**15 %**
A	16.4	8.7	24.1	14.7	17.0	12.6	21.5
B	15.3	8.3	22.2	13.4	15.9	10.3	22.1
C	7.9	4.6	11.3	6.0	8.6	6.1	10.4
D	9.3	5.7	12.9	4.8	10.8	7.6	11.6
E	6.5	3.8	9.3	4.8	7.1	5.1	8.5
F	8.7	5.3	12.0	4.6	10.0	6.5	11.8
G	8.5	4.6	12.4	7.9	8.7	6.2	11.2

As could have been expected from Figure 5-2, the total investment costs almost proportionally influence the costs of ECBM. The great deal of uncertainty about the drilling costs therefore has a large influence on the certainty of the CBM price. The sensitivity of the gas price to variation of the investment costs for both the production and the injection well, as well as the resulting total investment for drilling is shown in Figure 5-4. A high interest rate would be disastrous for ECBM projects.

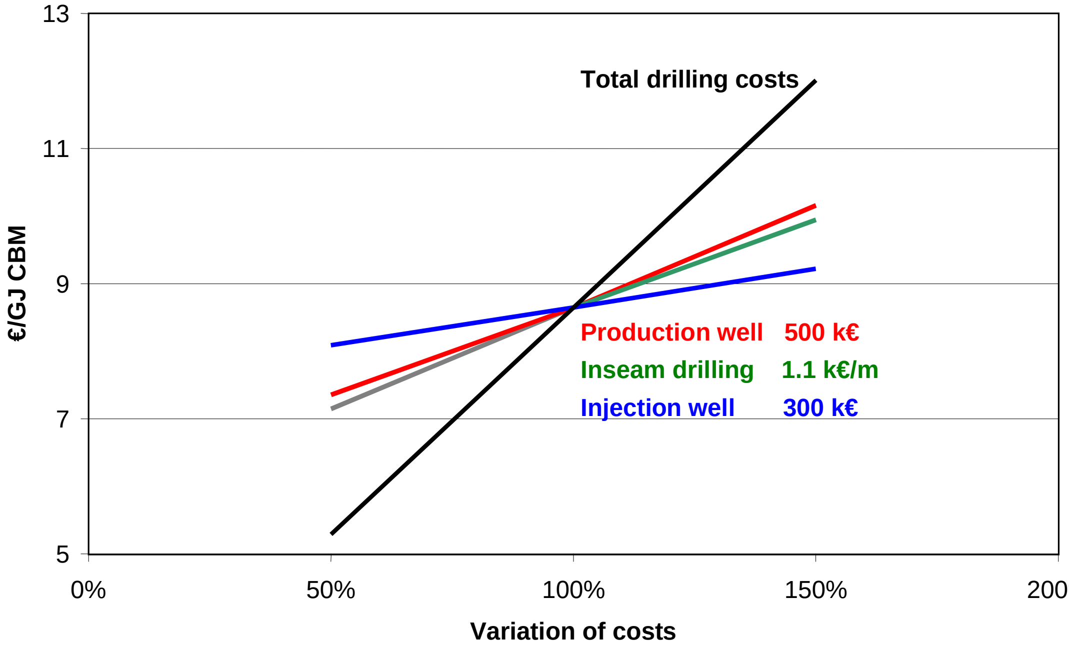


Figure 5-4. Influence of well drilling costs on CBM price for scenario F (1000×1000 m^2, 410 m inseam, skin –3, CO_2 injection from first year). No CO_2 bonus is applied.

The price of the produced CBM is furthermore heavily depending on the amount of CBM that can be produced per km^2. All calculations up to here were based on 29.6 Mm^3/km^2 Producible Gas in Place, a probable value for the Peel 3 sector. In Figure 5-5 the CBM prices from three areas are compared for proven, probable and possible reserves: The Peel 3 sector, Zuid Limburg as a whole and the Achterhoek 2 sector. The CBM reserves have been discussed in §4.2.

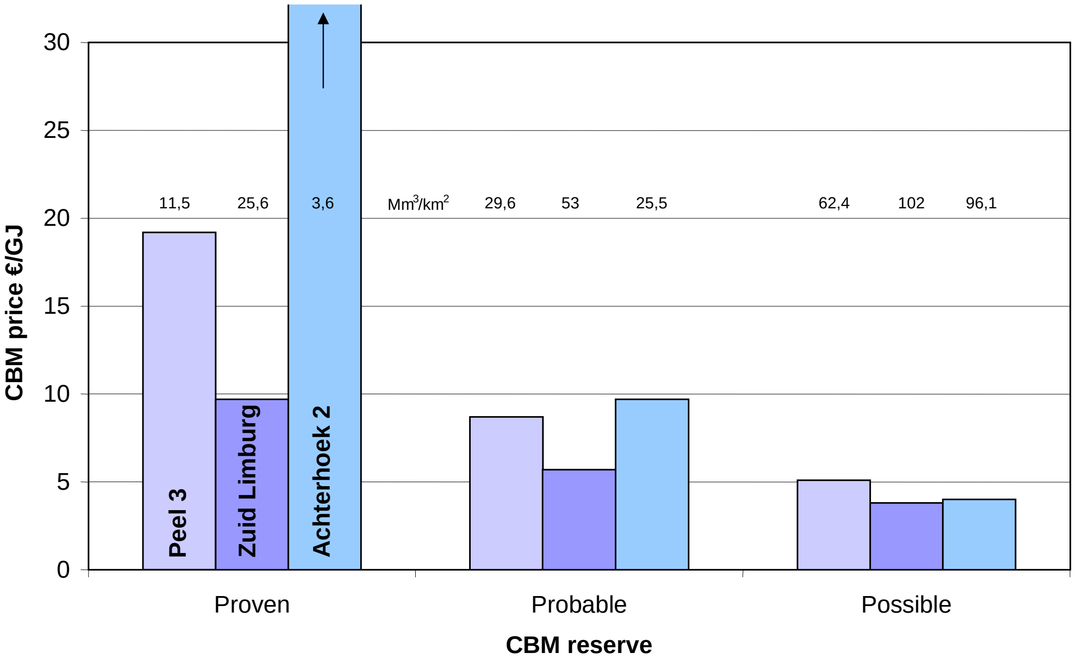


Figure 5-5. Price of CBM as a function of the CBM reserve probability for scenario F (1000×1000 m^2, 410 m inseam, skin –3, CO_2 injection from first year). Producible Gas In Place is indicated.

For an area with a high gas content, as is possibly the case in Zuid Limburg, the influence of the investment costs on the ECBM production price decreases and revenues from CO_2 sequestration become more important (Figure 5-6). With a bonus of only 20 €/tonne CO_2 sequestrated, costs for ECBM could decrease to 2.1 €/GJ, a very competitive value.

For probable reserves in other areas the producable ECBM can only be competitive if investment costs for well are halved and bonuses of 30 to 40 €/tonne CO_2 are applied concurrently.

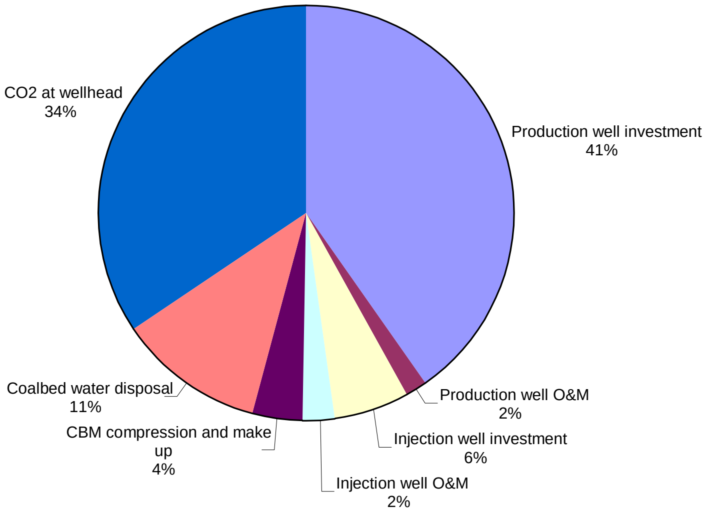


Figure 5-6. Breakdown of CBM price for scenario F (1000×1000 m^2, 410 m inseam, skin –3, CO_2 injection from first year) based on possible CBM reserve of Zuid Limburg. CO_2 costs are 15 €/tonne (no bonus).

5.3 CBM systems producing electricity

Instead of delivering the produced CBM to the natural gas grid, electricity can be generated on site. Because of the variable nature of the CBM flow over time, it has to be complemented with natural gas most of the time. If several CBM areas are exploited consecutively, the CBM flow can be nearly constant.

Most likely option for the near term future is a simple gas engine. At bigger scales combined cycles may be feasible (Kroon et al. 1998). The Solid Oxide Fuel Cell is included in this study because it offers the opportunity to provide cheap CO_2 to the CBM field (see Annex K).

The scale of the electricity systems in this study chosen in such a way that their CO_2 output exactly matches the CO_2 injection to the ECBM field. CO_2 from elsewhere will almost always be cheaper than CO_2 captured from the gas engine or the combined cycle. Therefore, for these cases, CO_2 can better be obtained from large industrial sources; the price at the wellhead is taken 15 €/tonne. CO_2 from an SOFC costs 4 €/tonne.

Depending on the presence of CBM in the subsurface, a 2 x 4 km^2 area would be provided with a 6 MW_e (9 MW_e for SOFC) to 21 MW_e installation (32 MW_e for SOFC). For the whole Peel 3 sector a 115 MW_e to 400 MW_e installation would be applicable. SOFC installations on this scale will not be available on short term. Because the CBM flow varies through the years, sometimes natural gas will be bought and sometimes the excess CBM can be injected to the grid. The market price used for cost calculations is 0.09 €/m^3. Table 5-5 gives the price of electricity produced from CBM, for comparison: the actual electricity production price in the Netherlands is 3.2 € cent/kWh.

Table 5-5. Price of small-scale electricity from CBM. Interest rate is 10%, lifetime is 30 years. Investment costs for gas engine and combined cycle stem from (Kroon et al. 1998) and (Beeldman et al. 1997).

	investment costs	**LHV efficiency**	**Electricity price (€ cent/kWh)**	
			102 Mm3 CBM/km2 25 €/tonne CO_2 bonus	29.6 Mm3 CBM/km2 no bonus
Gas engine	700 €/kW	34 %	2.7	7.5
Combined cycle	750 €/kW	42 %	3.3	7.8
SOFC	1500 €/kW	55 %	3.6	6.6

5.4 CBM systems producing hydrogen

When no heat demand is present, hydrogen production from CBM might be the best option if there is a considerable demand for hydrogen. Pure and easy accessible carbon dioxide (4 €/tonne at the wellhead) is a co product in hydrogen production.

0 gives an overview on hydrogen production technologies and accompanying costs. Investment costs for a Steam Reforming Hydrogen plant are typically between 2000 and 4000 €/(m^3 CBM/h), but for small plants these costs can increase to 7000 €/(m^3 CBM/h). The scale of the hydrogen plant chosen matches the amount of CO_2 needed for injection.

For scenario F on a 2 x 4 km2 field in the Peel 3 sector the plant will be small, producing 38 to 80 Mm^3 H_2 annually (, and have relatively high investment costs: 6000 to 8000 €/ (m^3 CBM/h). The price of the produced hydrogen ranges from 5.5 €/GJ to 12.7 €/GJ. This means that small scale hydrogen production on a CBM field can be competitive with conventional hydrogen produced from coal, which costs about 7.8 €/GJ (Williams 1999).

6 Discussion and conclusions

This study comprises a first feasibility study of Enhanced Coal Bed Methane Recovery by CO_2 injection in deep coal layers in the Dutch context. It shows that both the CO_2 storage potential as well as the energy production potential of this option could be very large. ECBM could play an important role as a backstop option for meeting the Kyoto targets for GHG emission reduction and supplement the national energy supply with emission free natural gas. Furthermore, it is concluded that ECBM production may be economically competitive on short term already, provided more detailed insights are obtained in geological conditions, drilling techniques and a number of, potential non-technical barriers.

Contents of the work

This study investigated the technical and economic feasibility of using CO_2 for the enhanced production of coal bed methane (ECBM) in the Dutch context. This concept could lead to both CO_2 storage by adsorbing CO_2 in deep coal layers that are not suitable for mining, as well as production of methane. Roughly said, ECBM leads to production of one molecule of methane for every two molecules of CO_2 injected.

The work included an investigation of the potential CBM reserves in the Dutch underground and the related CO_2 storage potential in deep coal layers. The latter was also supported by laboratory experiments on the adsorption capacity of coal. Furthermore, an economic evaluation of ECBM recovery was made by analysing the costs of capturing CO_2 from major stationary sources and CO_2 transport, modelling the production of ECBM using CO_2 injection with reservoir simulations and system analyses to investigate the costs (and it's sensitivities) of gas production. Furthermore, the costs of on-site hydrogen and power production (including on site CO_2 removal and injection) were evaluated as well as costs for waste water treatment and gas processing.

ECBM and CO_2 storage potentials

The technical potential of CBM in the Dutch underground is significant: a maximum reserve of about 60 EJ is stored in coal layers up to a depth of 2000 m. This figure should be compared to the current annual energy consumption of the Netherlands (about 3 EJ) or the known reserves of natural gas in the Netherlands (about 70 EJ in 1994). These reserves are concentrated in four main areas in the Netherlands: Zuid Limburg, the Peel area, the Achterhoek area and Zeeland. More coal is present in deeper deposits, but it is unlikely these can be explored for CBM because of their depth, implying lower permeabilities and lower CBM content due to increased temperature. The CO_2 storage potential could be about 8 Gtonne of CO_2. This storage potential should be compared to the annual CO_2 emissions of the Netherlands: about 180 Mtonne of CO_2. This means, theoretically, that the total CO_2 emissions of the Netherlands could be stored in coal layers for over 40 years and that CBM could meet the total national energy demand of the Netherlands for 20 years.

This assumes a replacement of 1 molecule of methane by 2 molecules of CO_2. In practice, this replacement ratio could be even higher for supercritical CO_2 at pressures higher than about 7.5 MPa. Further, an extra amount of CO_2 can be stored as free gas in the cleat system of the coal.

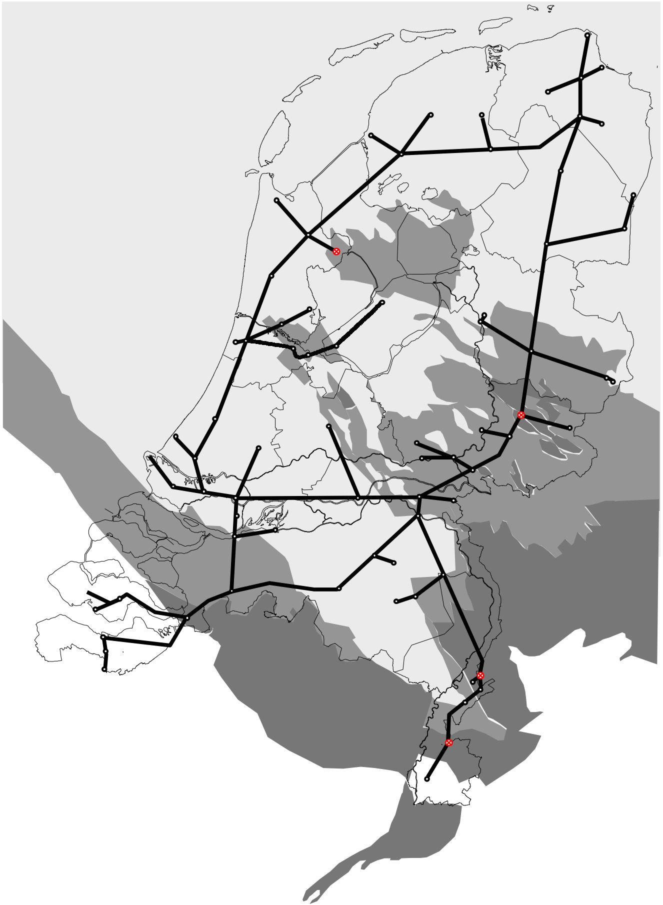


Figure 6-1. CO_2 grid and top Carboniferous in the Netherlands.

However, it is still uncertain to what extent these reserves can be accessed. With conservative assumptions regarding the potential completion and recovery rate of CBM from coal layers by means of drilling and CO_2 injection, as well as by limiting the ECBM recovery to a depth range of 500 – 1500 metres, the 'proven' reserves could be limited to 0.3 EJ and the 'possible' reserves up to about 3.9 EJ (or: equivalent to $9 \cdot 10^9$ - $109 \cdot 10^9$ m^3 methane). The accompanying CO_2 that can be sequestrated than lays between 54 Mtonne and 0.6 Gtonne.
Although those figures are far more modest than the 'technical' potential, they are still significant. In case the 'possible' reserves can be accessed, ECBM could supply 5% of the current national energy use on a more than carbon neutral basis for over 25 years. Given the Kyoto targets for 2010 (a reduction of 6% of the national GHG emissions compared to 1990 levels), or the national targets for renewable energy (10% renewable energy in 2020) this is a very significant amount. This applies to both the energy supply, as well as CO_2 storage potential (over 24 Mtonne per year, which is over 12% of the current national CO_2 emissions).

This study has shown that the Netherlands emits over 50 Mtonne of CO_2 per year from larger central facilities like power plants and chemical plants. About 10% of this amount is emitted by facilities like hydrogen factories which have (very) low CO_2 removal costs. The remaining CO_2 emissions could be collected at cost levels between 30 and 60 €/tonne of CO_2. CO_2 transport costs depend on distance and total volumes transported per year (thus, the capacity of the CO_2 infrastructure) and can vary between 1.5 €/tonne for 50 km transport for 1 Mtonne CO_2/yr up to 66 €/tonne for 0.1 Mtonne CO_2/yr over a distance of 300 km. A significant scale of CO_2 transport is therefore desirable when this option is developed commercially.

Economics of ECBM in the Netherlands
Without any subsidies or carbon taxes, the cost levels for ECBM recovery ranges from 3.5 to 6.5 €/GJ methane produced. Those values apply for the most suitable field set-up of a 1000×1000 m^2 well spacing (two wells are placed per square kilometre). Those values also include the costs for CO_2-removal at larger point sources (such as ammonia and power plants) and transport to the CBM field. The various scenario's that were evaluated indicate that a wide well spacing, but therefore also relatively slow production rate of CBM fields, is most economic.
These costs levels come close to the projected natural gas prices in Europe in a timeframe of 10 to 20 years, which are projected to be between 2.5 and 3.2 €/GJ. Inclusion of a carbon tax (or bonus) per tonne CO_2 sequestrated of 25 €/tonne, lowers the price of ECBM to a competitive 1.5 to 4 €/GJ. The cost level of CO_2 sequestration through ECBM is comparable with projected cost levels for CO_2 storage in aquifer traps (9 to 52 €/tonne, Wildenborg et al. 1999) in case the CBM would be sold for current natural gas prices.

Drilling costs for both the CO_2-injection wells and methane production wells dominate the ECBM production costs (up to 2/3 of the total production costs). The second factor are the costs for CO_2 removal and supply. Gas treatment, waste water treatment and O&M costs (mainly related again to the wells) are less important factors. In case high gas production rates are obtained (which depends on both drilling techniques and the thickness and gas content of the coal layers at the location in question), the importance of the drilling costs decreases somewhat (to about 40%) and the relative share of CO_2 costs increases.

Because the costs of CO_2 are a relevant factor, on site conversion of CBM to power or hydrogen including CO_2 removal and direct injection could be considered. If the produced CBM is used for electricity or hydrogen production on top of the CBM field (thereby eliminating CO_2 transport costs), the resulting CO_2 can be injected in the coal directly. CO_2 removal from a gas engine or a combined cycle is currently more expensive when compared to CO_2 from industrial processes that must be transported to the CBM field. But a (SOFC) fuel cell produces a pure and therefore much cheaper CO_2 stream. Although SOFC fuel cells are not fully commercially available and have high capital costs, they could lead to somewhat lower costs of electricity. Without CO_2 bonus, on site power generation is more expensive than grid prices for the systems considered. But when a CO_2 bonus of 25 €/tonne CO_2 is assumed, power generation costs are reduced below 3 € cent/kWh, which is lower than the current average 3.2 € cent/kWh observed for power generation in the Netherlands. On the longer term, when SOFC fuel cells could become cheaper, on site power generation could become a (very) attractive alternative.

On site (smaller scale) hydrogen production gives similar results. Capital costs for smaller scale on site hydrogen production are relatively high, but with a CO_2 bonus of 25 €/tonne, hydrogen costs could be lower than current production costs from coal and comparable to production costs from natural gas.

Overall, the results of the economic evaluation indicate that CBM by means of enhanced recovery by CO_2 injection in deep coal layers can be performed at competitive cost levels when the right system configurations are chosen. A, relatively modest, carbon tax (or 'bonus') of 25 €/tonne could easily tick the balance in favour of ECBM recovery in Dutch conditions on short term already.

Uncertainties and potential barriers

However, a number of important (geo) technical and geological factors play a key role in whether these cost levels can be obtained or not. The dominating factors in the costs are the drilling costs. In case the costs per wellhead appear to be higher than assumed here, the economic performance of the system deteriorates. On the other hand innovations in drilling techniques, gaining more experience with the required drilling methods over time and obtaining 'economies of scale' by drilling relatively large numbers of wells in a short time to exploit larger CBM fields may bring drilling costs (and thus CBM production costs) down considerably. Another important assumption regarding drilling is that inseam drilling over larger distances is feasible for ECBM systems. Experience with inseam drilling in (series of thin) coal seams is rather limited as and needs further investigations, testing and development. The same applies for developing drilling methods which are dedicated for the type of production and injection wells needed for the relatively slow gas injection and production rates that apply to ECBM systems. Potentially, such wells could be (much) cheaper than e.g. natural gas production wells.

Regarding to the geology, the CBM potential and the actual accessibility of the, theoretical, CBM reserves and the predicted presence of producable CBM gas in the coal layers is subject to broad ranges. More detailed surveys of the Dutch underground are needed to reduce uncertainties about CBM gas reserves. This can be obtained by seismic research and obtaining more and better samples of the Dutch underground. Such research is absolutely essential before ECBM is developed in the Netherlands on a significant scale.

The presence of large faults and minor fracture systems in the coal seams may reduce the average lateral size of CBM fields and in such a way it may increase drilling costs. This needs further investigation. In addition, the coal-overburden integrity for Carboniferous shales and sandstones regarding uncontrolled escape of methane and carbon dioxide requires further attention. Furthermore the parameters for porosity and permeability that are used in modelling CBM production need more accurate defining. The presented preliminary results are valid up to a depth of about 700 m. Also, the effects of water salinity and presence of other gases than CO_2 and CH_4 are not investigated. Another issue will be the gathering of large coal samples of high quality, which are comparable with Dutch coals in age, maceral content, depths of burial and tectonic history.

The actual implementation of ECBM in the Netherlands is likely to encounter a number of non-technical barriers as well. The required infrastructure for CO_2 transport must be built and realized over time. The related potential (safety) risks of such infrastructure are not dealt with in this study and require further attention. Since low CO_2 costs are partly determined by larger scale distribution, a combination of ECBM and CO_2 storage in acquifers and empty gas fields may become an attractive scenario when CO_2 removal is fully developed. Scenario's to develop CO_2 removal capacity and infrastructure over time need to be developed. Since the equipment involved is capital intensive and has a long lifetime, intelligent planning over time is required. This needs further study. Such analyses should also include possibilities to import or export CO_2 to neighbouring countries such as the Ruhr area in Germany or the North Sea area.

In addition, exploration of CBM fields by enhanced recovery may involve drilling wells in areas that are populated or reserved for nature or recreation. Although waste water treatment that meets stringent standards seems feasible and well take a small amount of space after being installed, impacts regarding emissions and impacts on landscape need further attention as well. In order to reduce the impact on the landscape deviated drilling is an option. But currently little is known about this technology and obtainable cost levels, especially for ECBM applications.

Conclusion

In conclusion, this study showed that ECBM is likely to become an economically feasible option for the Netherlands on relatively short term. It could at least play a significant (and potentially very large) role in reducing greenhouse gas emission levels for a time period of about 50 years. Although the estimates of energy reserves in the form of CBM are uncertain, they are potentially very significant (varying from 6 – 60 EJ). The potential CO_2 storage capacity is (very) large as well (1-8 Gtonne of CO_2). Given the fact that CO_2 binds well to the coal matrix, that deep coal layers are unlikely to be accessed for mining or other activities in the future and that CO_2 storage with ECBM delivers a clean fossil fuel as a by-product, coal layers may be a preferable CO_2 storage medium when compared to (saline) aquifers, empty gas fields or in deep oceans.

Therefore, this option deserves further development and study. A mix of more detailed geological surveys combined with getting good quality samples, laboratory experiments, system studies on implementation scenario's and a pilot project (with a special focus on drilling techniques) is recommended. All this could be induced by a dedicated research programme, preferably set-up in an international context including neighbouring countries like Germany and Belgium, France and Poland. Collaboration with parties involved in demonstration ECBM in the United States and Canada is recommended as well.

Given the expected large potentials for this option in countries in Eastern Europe, China and parts of (southern) Africa, export of knowledge and technology is likely to have considerable market potential on the shorter to medium term and provides interesting chances for Dutch industry.

7 Key recommendations

CO_2 capture and disposal through ECBM is a promising option for reducing greenhouse gas emissions in the Netherlands. ECBM is expected to be inherently safe and likely to become economically feasible; its CO_2 storage potential is large. Based on this study the key recommendations are:

- Improve the insights and degree of certainty of producable CBM reserves in the Dutch underground by means of detailed geological surveys and samples of the underground.
- To improve the insights in reservoir characteristics of the coal layers with respect to greater depths and fluid/gas characteristics, e.g. with more advanced laboratory experiments.
- To get a better perception on the coal roof rock integrity with respect to gas evasion during production; this is especially relevant for guaranteeing the long-term storage of CO_2.
- To gain more knowledge on drilling technologies suitable for the situation in the Netherlands and their accompanying costs. This applies in particular to deviated and in seam drilling techniques.
- To investigate implementation schemes and scenario' s for ECBM in the Netherlands that includes the development of CO_2 infrastructure and removal capacity over time. Integrated planning with 'conventional' CO_2 storage and international aspects should be included in such analyses.
- To thoroughly investigate accompanying safety and environmental risks, spatial impacts and social acceptance.
- Last but not least; to initiate a pilot project, in order to gain necessary practical experience with ECBM production schemes, in particular with respect to local reservoir characteristics and drilling techniques. An interesting location may be Zuid Limburg, where cheap CO_2 may be obtained from the ammonia production at DSM- Geleen or the coal gasification plant at Buggenum. Also, the knowledge about the coal reserves in this region is currently most detailed and relatively high gas production rates can be expected in this area.

8 Literature

Advanced Resources International Inc., 1998, Enhanced coal bed methane recovery with CO_2 sequestration, Arlington, 139 pp.

Arri LE, Yee D, Morgan WD and Jeausonne MW, 1992, Modelling coalbed methane production with binary gas sorption, in proceedings of SPE Rocky Mountains Regional Meeting, SPE 24363, Society of Petroleum Engineers, Casper, pp 459-472.

Barzandji OH, Wolf K-HAA and Bruining J, 2000, Combination of laboratory experiments and field simulations on the improvement of CBM production by CO_2 injection, in proceedings of Second International Conference on Methane Mitigation, Novosibirsk, pp 325-336.

Beeldman M, Bais JM and Menkveld M, 1997, Technologisch Raamwerk voor een optimale energie infrastructure: Energievoorziening in het Land over de Waal, Nijmegen, ECN-Beleidstudies, Petten.

Bertheux WB, Wolf K-HAA, Barzandji OH and Bruining J, 2000, CO_2-Enhanced coalbed methane production in dry and water saturated coals: experiments, simulations and image analysis, NOVEM Technical Report, Contract no. 234130/9001, TU Delft, Delft.

Blok K, Williams RH, Katofsky RE and Hendriks CA, 1997, Hydrogen production from natural gas, sequestration of recovered CO_2 in depleted gas wells and enhanced natural gas recovery, Energy, the International Journal, 22: 161-168.

Bond RL, 1967, Porous carbon solids, London.

Brande S, Chernov N and Turner M, 1999, Fracture analysis form coal fragment shape: Digital image processing and the geometry of particle perimeters, Draft: to be submitted to the International Journal of Coal Geology.

Bruggeman G, 1994, Referentielijst van in Nederland in bedrijf zijnde warmte/kracht installaties op basis van turbines, report no. V.1.106, Stuurgroep Rationeel Energiegebruik, VEMW, v/h Krachtwerktuigen, Amersfoort.

Bustin RM and Clarkson CR, 1998, Geological controls on coalbed methane reservoir capacity and gas content, International Journal of Coal Geology, 38: 3-26.

Chemical Week, 1998, product focus ammonia, 160(41): 49.

Chemical Week, 1998, product focus EO-EG, 160(21): p. 1.

Chen G and Harpalani S, 1995, Study of coal networks in coal, from: Fractured and and jointed masses, Balkema, Rotterdam, pp 431-434.

Chi SM, Morsi BI, Klinzig GE and Chiang SH, 1987, Interfacial property of coal under high pressure, in: Moulijn et al. (ed.) proceedings of International Conference on Coal Science, Elsevier Science Publishers, Amsterdam, pp 459-462.

Clark WF and Hemler T, 1998, Completing, equipping, and operating fruitland formation coalbed methane wells in the San Juan Basin, New Mexico and Colorado, in: Fassett JE (ed.), Geology and coal bed methane resources of the northern San Juan Basin, New Mexico and Colorado - Rocky Mountain Association of Geologists, pp 125-132.

Daniels BW, 2000, personal communication, IVEM, Groningen.

Davidson RM, Sloss LL and Clarke LB, 1995, Coalbed methane extraction, IEA Coal Research, London.

de Biasi V, 1999, 250-kW fuel cell-gas turbine hybrid to start operational testing next year, Gas turbine world, July-August: 12.

de Haan MFE, 1999, Enhanced coalbed methane production by carbon dioxide injection; theory, experiments and simulation, NOVEM Technical Report, Contract no. 234130/9001, TU Delft, Delft.

Elliot MA, 1981, Chemistry of coal utilization.

EPA, 1997, A guide to financing coalbed methane projects, US Environmental Protection Agency.

Faaij A, Meuleman B and van Ree R, 1998, Long term perspectives of biomass integrated gasification with combined cycle technology, Novem, Utrecht, 93 pp. + annexes.

Farla JCM, Hendriks CA and Blok K, 1995, Carbon dioxide recovery from industrial processes, Climatic Change, 29: 439-461.

Feron PHM and Jansen AE, 1998, Techno-economic assessment of membrane gas absorption for the production of carbon dioxide from flue gas, in proceedings of Fourth International Conference on Greenhouse Gas Control Technologies, Interlaken.

Fulton PF, Parente CA, Rogers BA, Shah N and Reznik AA, 1980, A laboratory investigation of enhanced recovery of methane from coal by carbon dioxide injection, in proceedings of Unconventional Gas Recovery Symposium, SPE/DOE 8930, Society of Petroleum Engineers, Pittsburgh, pp 65-72.

Gregoire Padró CE and Putsche V, 2000, Survey of the economics of hydrogen technologies, National Renewable Energy Laboratory, Golden.

Gunter WD, Gentzis T, Rottenfusser BA and Richardson RJH, 1997, Deep coalbed methane in Alberta, Canada: a fuel resource with the potential of zero greenhouse gas emissions, Energy Conversion Management, 38, Suppl.: S217-S222.

Hall FE, Chunhe Z, Gasem KAM, Robinson RL and Yee D, 1994, Adsorption of pure methane, nitrogen and carbon dioxide and their binary mixtures on wet fruitland coal, SPE 29194, Eastern Regional Conference and Exhibition, Charleston, pp329-244.

Hendriks C, 1994, Carbon dioxide removal from coal-fired power plants (thesis), Utrecht University, Utrecht, 260 pp.

Hydrocarbon Processing, 1998, Gas processes '98.

Ishibashi M, Otake K and Kanamori S, 1998, Study on CO_2 removal technology from flue gas of thermal power plant by physical adsorption method, in proceedings of Fourth International Conference on Greenhouse Gas Control Technologies, Interlaken.

Katofsky RE, 1993, The production of fluid fuels from biomass, Center for Energy and Environmental Studies/Princeton University, Princeton.

Kim A, 1977, Estimating methane content of bituminous coalbeds from adsorption data, Report of Investigations 8245, US Department of the Interior - Bureau of Mines.

Krans TF, 1986, Eindrapport project inventarisatieonderzoek Nederlandse kolenvoorkomens, Report GB 2107 of the Geological Survey of the Netherlands, Geologisch Bureau Heerlen, Rijks Geologische Dienst, Heerlen.

Kroon P, et al., 1998, Nationale Energie Verkenningen 1995-2020, Report No. ECN-C--97-081, ECN-Beleidsstudies, Petten, 140 pp.

Krooss BM, Gensterblum Y, Siemons N and Prinz D, 2000, Adsorption of methane, carbon dioxide and mixtures on dry and moist Carboniferous coals of different rank, RWTH Aachen, Aachen.

Levy J, Day SJ and Killingley JS, 1997, Methane capacity of Bowen Basin coals related to coal properties, Fuel, 74: 1-7.

Massaratto P, 1999, Cost benefit analysis of coalbed methane recovery activities in Australia and New Zealand - implications for commercial projects and government policy, in: Mastalerz M, Glikson M and Golding SD (eds.), Coalbed methane: Scientific, environmental, and economical evaluation, Kluwer Academic Publishers.

McElhiney JE, Paul GW, Young GBC and McCartney JA, 1993, Reservoir engineering aspects of coalbed methane, in: Law BE and Rice DD (eds.), Hydrocarbons from coal: AAPG studies in geology 38, pp 361-372.

Ministerie van Economische Zaken, 1995, Derde energienota, SDU uitgeverij, Den Haag, 199 pp.

Mozaffarian M, 1994, Hydrogen production methods, ECN Fossil Fuels, Petten.

OECD, 1996, National accounts - Main aggregates, Edition 1997, Paris, 170 pp.

Pagnier HJM, Pestman PJ and van Tongeren PCH, 1987, Recent coal exploration in the Netherlands, in: Martin JW and Barone SP (eds.), proceedings of 13th Annual Underground Coal Gasification Symposium, Laramie.

Pattison CI, Fielding CR, Mc Watters RH and Hamilton LH, 1996, Nature and origin of fractures in Permian coals from the Bowen Basin, Queensland, Australia, in: Gayer R and Harris I (eds.), Coalbed methane and coal geology, Geological Society Special Pubication no. 109, London, pp 131-150.

Perry RH, Green DW and Maloney JO, 1987, Perry's chemical engineers' handbook, sixth edition, McGraw-Hill Book Co, Singapore.

Puri R and Yee D, 1990, Enhanced Coalbed Methane REcovery, SPE paper 20732.

Reichle D, Houghton J, Kane B and Ekmann J, 1999, Carbon sequestration, state of the science - A working paper for roadmapping future carbon sequestration R&D - draft, US Department of Energy, 223 pp.

Reznik AA, Singh PK and Foley WL, 1982, An analysis of the effect of carbon dioxide injection on the recovery of in-situ methane from bituminous coal: an experimental study, in proceedings of Unconventional Gas Recovery Symposium, SPE/DOE 10829, Society of Petroleum Engineers, Pittsburgh, pp 975-990.

Riesenfeld FC and Kohl AL, 1974, Gas Purification, Gulf Publishing Company, Houston, 761 pp.

RIVM, 1999, Milieubalans 99: Het Nederlandse milieu verklaard, Rijksinstituut voor Volksgezondheid en Milieu, Bilthoven, 182 pp.

Sawyer WK, Zuber MD, Kuuskraa VA and Horner DM, 1987, Using reservoir simulation and field data to define mechanisms controlling coalbed methane production, in proceedings of Coalbed Methane Symposium, Tuscaloosa.

Schaeffer GJ, 1998, Fuel cells for the future; a contribution to technology forecasting form a technology dynamics perspective, Enschede.

Schneider THA and Preuße A, 1995, Recovery and utilisation of coal seam gas - impetus by the German hard coal mining industry, Erdöl Erdgas Kohle, 111(12): 515-519.

Seidle JP and Arri LE, 1990, Use of conventional reservoir models for coalbed methane simulation, in proceedings of International Technical Meeting jointly hosted by CIM and SPE, Calgary.

Steinberg M and Cheng HC, 1989, Modern and prospective technologies for hydrogen production from fossil fuels, Int. J. Hydrogen Energy, 14(11): 797-820.

Stevens SH, Kuuskraa VA, Spector D and Riemer P, 1998, CO_2 sequestration in deep coal seams: Pilot results and worldwide potential, in proceedings of Greenhouse Gas Control Technologies Conference.

Stevens SH and Pekot L, 1999, CO_2 injection for enhanced coalbed methane recovery: Project screening and design, in proceedings of Coalbed Methane Symposium, Tuscaloosa.

Stevenson MD, Pinczewski WV, Somers ML and Bagio SE, 1991, Adsorption/desorption of multicomponent gas mixtures at in-seam conditions, SPE 23026.

Stork Engineering Consultancy BV, 1999, Draft report for assessment of leading technology options for abatement of CO_2 emissions; IEA greenhouse gas R&D programme.

Stuffken J, 1957, De mijngasafgifte van kolenlagen, PhD thesis (in Dutch), TH Delft, Delft.

Suda T, Fujii M, Yoshida K, Iijima M, Seto T and Mitsuoka S, 1992, Development of flue gas carbon dioxide recovery technology, in: Blok K, Turkenburg WC, Hendriks CA and Steinberg M (eds.), proceedings of First International Conference on Carbon Dioxide Removal, Pergamon Press, Amsterdam.

Turkenburg WC and Hendriks CA, 1999, Fossil fuels in a sustainable energy supply: the consequence of CO_2 removal (in Dutch), Science, Technology and Society/Utrecht University, Report No NWS-99032, Utrecht, 28 pp.

USDOE/EIA, 2000, Annual Energy Outlook.

van Bergen F, Pagnier HJM, David P and Krooss BM, 2000, Inventory of the potential volumes of methane extraction and carbon dioxide storage in the Dutch subsurface, TNO contribution to the Feasibility study of combined coal bed methane produciton and carbon dioxide storage in the Netherlands, TNO report NITG 00-272-B, Utrecht.

van Krevelen DW, 1993, Coal, Elsevier Science Publishers, Amsterdam.

Wenselaers P, Dusar M and van Tongeren PCH, 1996, Steenkoollaag methaangaswinning in het Kempisch kolenbekken; Het proefproject te Peer, Ministerie van de Vlaamse Gemeenschap, Brussels.

Wildenborg AFB, Hendriks C, van Wees JD, Floris F, van der Meer LGH, Schuppers J, Blok K and Parker-Witmans N, 1999, Kostencalculatie van CO_2-verwijdering via ondergrondse opslag, NITG TNO, Haarlem.

Williams RH, 1998, Fuel cells, coal, and China, in proceedings of Ninth Annual U.S. Hydrogen Meeting: Implementing Global Energy Solutions, Washington.

Williams RH, 1999, Toward zero emissions for coal - roles for inorganic membranes, in proceedings of International symposium toward zero emissions: the challenge for hydrocarbons, Rome.

Wilson MA, Wrubleski RM and Yarborough L, 1992, Recovery of CO_2 from power plant flue gases using amines, in: Blok K, Turkenburg WC, Hendriks CA and Steinberg M (eds.), proceedings of First International Conference on Carbon Dioxide Removal, Pergamon Press, Amsterdam, pp 325-331.

Wolf K-HAA, Barzandji O, Bruining J and de Rooij M, 1999a, Feasibility study of CO_2-sequestration and Coalbed Methane Production. Report on modelling work, economics and related laboratory experiments on enhanced coalbed methane production by liquid carbon dioxide injection, NOVEM Technical Report, Contract no. 234130/9001, TU Delft, Delft.

Wolf K-HAA, Westerink HHE, van Delft PTP and Bruining J, 1997, Coalbed methane production in the Netherlands; an inventory, TU Delft/NOVEM, Delft.

Annex A CO$_2$ recovery technologies

C.N. Hamelinck (STS-UU)

A number of technologies are available for CO$_2$ recovery from gas streams. Generally a division can be made into:

- Chemical absorption
- Physical absorption
- Physical adsorption
- Membranes
- Distillation

The two absorption options are widely applied, and at present the most suitable for application to a broad range of CO$_2$ containing streams.

Chemical absorption using amines

Chemical absorption is a technology that makes use of chemical equilibria, shifting with temperature rise or decline. Basically, cool CO$_2$ binds chemically to the absorbent and is later stripped off by hot steam. Chemical absorption methods are especially useful with low CO$_2$ partial pressure (~0.1 bar) in the gas.

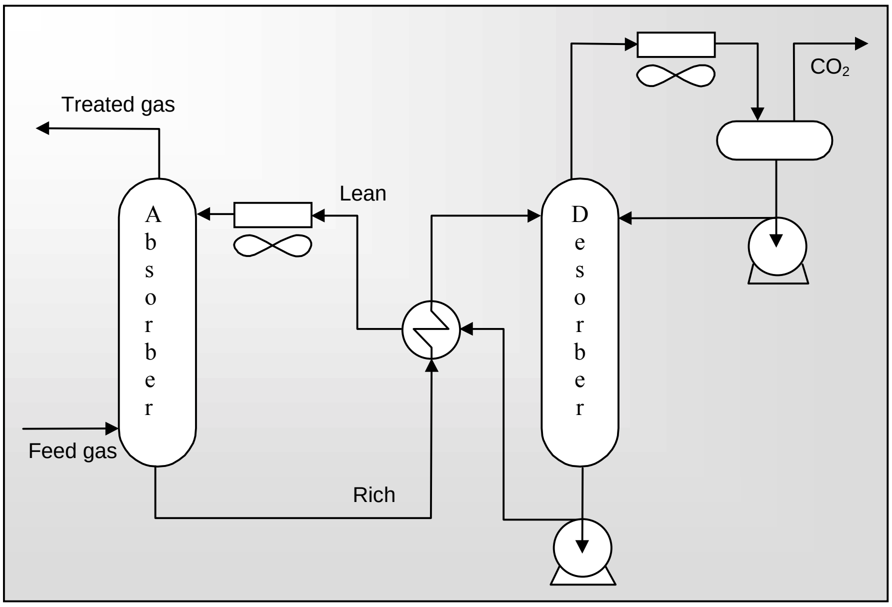


Figure A-1. The Fluor Daniel Econamine system (Hydrocarbon Processing 1998).

Process descriptions are given by (Hendriks 1994; Wilson et al. 1992). The gases enter a direct contact cooler where they are cooled by a circulating stream of water. The gas is then compressed with a blower to counteract the pressure drop (0.1 bar) through the absorber. Injection takes place at the base of the absorber tower where it contacts a counter current liquid stream of lean amine. The gases flow through the absorber countercurrent to the absorbent. The absorbent binds chemically with the carbon dioxide in the flue gases. The CO$_2$ lean gases then enter the wash section of the absorber where water and entrained absorbent are removed and returned to the absorber. The washed gases are vented to the atmosphere.

The CO$_2$ rich solution leaves the absorber and is pumped to the lean/rich cross heat exchanger. In the cross exchanger the CO$_2$ rich solution is heated and CO$_2$ lean solution is cooled.

The CO$_2$ rich amine solution is fed into the amine regenerator where the CO$_2$ is stripped of. The CO$_2$ release is achieved by heating the amine solution in the reboiler at the bottom of the tower. Water and absorbent are vaporised, leave the reboiler and enter the regenerator. The vapours move up in the regenerator condensing while liberating the CO$_2$ and heating the downflowing solution. Steam and CO$_2$ end up in the top of the regenerator while the lean amine leaves the tower at the bottom. Some vapour and CO$_2$ enter the wash section of the regenerator where absorbent vapour is removed. The unit also houses an amine reclaimer where solid waste products can be removed and degraded amine can be converted back to amine for reuse

The mixed CO$_2$ and water vapour leaving the top of the regenerator tower is fed into a condenser where the water can be removed and the CO$_2$ is cooled. The condensed water is returned to the regenerator.

The CO$_2$-lean solution leaves the reboiler and enters the cross exchanger where it is cooled. The solution is then pumped and cooled further before it re-enters the absorber.

Commonly used absorbents are alkanolamines. They are applied as solutions in water. Alkanolamines can be divided into three classes: primary, secondary and tertiary amines. Most literature is focused on primary amines, especially monoethanolamine, which is considered the most effective in recovering CO_2 (Farla et al. 1995; Wilson et al. 1992), although it might well be that other agents are also suitable as absorbents (Hendriks 1994). The Union Carbide "Flue Guard" process and the Fluor Daniel Econamine FG process (formerly known as the Dow Chemical Gas/Spec FT-1 process) use MEA, combined with inhibitors to reduce amine degradation and corrosion.

Economics

The cost of amine based capture are determined by the cost of the installation, the amines, the steam for scrubbing and the electric power. The following cost figures stem from the commercially applied Econamine FG Process (Hendriks 1994).

For flue gases with a CO_2 concentration of 8% a train size for the Econamine FG process of 42 tonne CO_2 per hour, is taken as basis. Recoveries are 95 – 99 %; purity is 98 – 99 % on dry basis. The investment for this train amounted to 22 MUS$$_{1994}$. Included in these costs are flue gas cooler, flue gas blower, heat exchanger, and a reclaimer to clean the solvent from contaminants, such as heat-stable salts. The investment costs are inversely proportional to the CO_2 concentration in the feed gas when these range from 4 to 8 %. There are no cost figures known for higher CO_2 concentration in the flue gas. Assumed is that a higher CO_2 concentration will lead to a proportionally smaller absorber. In the base case the cost for the absorber are about 40 % of the total investment of the absorption unit. The R-value for size differences is taken 0.8.

The investment can therefore be expressed with:

$$I = (I_{42tph,fix} + I_{42tph,\mathrm{var}} \times \frac{c_0}{c}) \times (\frac{m}{m_0})^R \times f \qquad \text{Equation A-1}$$

with I = investment in M€

$I_{42tph,fix}$ = fixed investment for 42 tonne CO_2/h = 13.2 US$$_{1994}$

$I_{42tph,var}$ = CO_2 concentration dependent investment for 42 tonne CO_2/h = 8.8 US$$_{1994}$

c_0 = base case CO_2 concentration = 8 %

c = actual CO_2 concentration in %

m_0 = base case CO_2 flow = 42 tonne/h

m = actual CO_2 flow

R = scale factor = 0.8

f = currency inflation factor from US$$_{1994}$ to €$_{2000}$ = 1.22

Annual O&M costs are assumed to be 3.6 % of the investment plus the cost for purchase of chemicals and disposal of chemicals used. MEA is partly entrained in the gas phase, this results in chemical consumption of 0.5 – 2 kg or 2.2 € per tonne CO_2 recovered, assuming no SO_2 in the flue gases (Suda et al. 1992; Farla et al. 1995). The presence of SO_2 leads to an increased solvent consumption. Assuming 70 ppm SO_2 in the flue gases the extra consumption of MEA amounts to 1.5 kg per tonne CO_2 recovered. The cost of the extra solvent amount to another 2.2 € per tonne CO_2 recovered. Used MEA can be disposed of by combustion in refuse incinerators where the MEA and its formed salts are converted to CO_2, H_2O, N_2, SO_2 and NO_x. Disposal of MEA costs around 110 € per tonne, 0.22 € per tonne CO_2 recovered (Hendriks 1994).

The heat consumption of the Econamine FG process lays between 3.8 MJ/kg CO_2 (Suda et al. 1992) and 4.2 MJ/kg CO_2 (Farla et al. 1995) by means of 2.3 bar / 130 - 160 °C steam. Hendriks writes about LP steam 3690 - 4900 kJ/kg CO_2 at 192 and 182 °C respectively. We apply the 3.8 MJ/kg value in this study; the price for steam is taken 0.02 €/kWh.

The electric power consumption for flue gas and stack gas blowers together is 48 kWh per tonne or 173 kJ/kg CO_2 recovered (Suda et al. 1992). The price of electricity is 0.05 €/kWh.

Physical absorption

When the CO_2 content makes up an appreciable fraction of the total gas stream, the cost of removing it by heat regenerable reactive solvents may be out of proportion to the value of the CO_2. To overcome the economic disadvantages of heat regenerable processes, physical absorption processes have been developed which are based on the use of essentially anhydrous organic solvents which dissolve the acid gases and can be stripped by reducing the acid-gas partial pressure without the application of heat. Of course they require a high partial pressure of the acid gases in the feed gas to be purified, 9.5 bar is given as an example by (Hendriks 1994). Most physical absorption processes found in literature are Selexol, which is licensed by Union Carbide, and Lurgi's Rectisol, these processes are commercially available and frequently used in the chemical industry.

The Selexol process is extensively described (Hydrocarbon Processing 1998; Hendriks 1994; Riesenfeld and Kohl 1974). In a countercurrent flow absorption column the gas comes into contact with the solvent, a 95 % solution of the dimethyl ether of polyethylene glycol in water. The CO_2 rich solvent passes a recycle flash drum to recover co-absorbed CO and H_2. The CO_2 is recovered by reducing the pressure through expanders. This recovery is accomplished in serially connected drums. The CO_2 is released partly at atmospheric pressure. After the desorption stages, the Selexol still contains 25 - 35 % of the originally dissolved CO_2. This CO_2 is routed back to the absorber and is recovered in a later cycle.
The CO_2 recovery rate from the gas stream will be approximately 98 to 99 % when all losses are taken into account. Half of the CO_2 is released at 1 bar and half at elevated pressure: 4 bar. Minor gas impurities such as carbonyl sulphide, carbon disulphide and mercaptans are removed to a large extent, together with the acid gases. Also hydrocarbons above butane are largely removed. Complete acid-gas removal, i.e. to ppm level, is possible with physical absorption only, but is often achieved in combination with a chemical absorption process.

An alternative set-up would be a further flashing of the solvent to very low pressures, to achieve a higher recovery rate. Whether or not a vacuum flash drum should be chosen, will depend only on economic considerations. It should be noted that a vacuum flash drum reduces the circulation rate and the pumping energy but increases the compression energy for the recovered CO_2.

Although in (Hydrocarbon Processing 1998) it is written that the plant cost and utilities vary with the application and cannot be generalised, (Hendriks 1994) gives an estimation for a 436 tonne/h Selexol system. The costs of the absorption and desorption unit are 40 $MU\$_{1988}$. Corrected for inflation, this would be 59 M€. The yearly solvent consumption is about 70 tonne, mainly due to mechanical losses. The replacement costs are approximately 0.2 $MU\$_{1990}$ (0.3 M€), this is considered as operational costs.

In the Selexol recovery process, compressing and pumping the Selexol require energy. The power demand for pumping can be calculated from the following relation. (Hendriks 1994)

$$P_p = q_v \times \frac{\Delta p}{\eta_p} \qquad \text{Equation A-2}$$

where P_p = power demand in W
q_v =flux in m^3/s
Δp = pressure difference in Pa
η_p = pumping efficiency

The flux q_v is calculated as follows, The solubility of CO_2 is 20 Nm^3 per m^3 of Selexol at 2500 kPa. With a desorption ratio of 0.65 the circulation rate of Selexol must be 5 m^3/s to absorb 436 tonne of CO_2 per hour. The Selexol must be compressed from atmospheric pressure to 2500 kPa. Furthermore, a pressure drop of 100 kPa in the system is assumed.
Assuming $\eta_p = 0.70$, the power demand amounts to 17 MW_e. About 50 % of this energy is recovered by reducing the pressure of the Selexol, which leaves a net power consumption of 9 MW_e.

Hendriks (1994) researched the use of a Selexol system with a preceding shift in an ICGCC. This seems an attractive set-up for mainly this type of plants, while is already a high carbon concentration in a small gas volume. A shift followed by Selexol is also an option for BF and BOF gas in the iron and steel industry (Daniels 2000).

Other separation technologies
Physical adsorption systems are based on the ability of porous materials (e.g. zeolites) to selectively adsorb specific molecules at high pressure and low temperature and desorb them at low pressure and

high temperature. These processes are already commercially applied in hydrogen production, besides a highly pure hydrogen stream a pure carbon dioxide stream is co produced. Physical adsorption technologies are not yet suitable for the separation of CO_2 only, due to the high energy consumption. Research is ongoing (Katofsky 1993; Ishibashi et al. 1998)

Membranes are thin layers through which selective transport takes place, driven by a pressure difference across the membrane. The hollow fibre module is the one that is most frequently used. The current state of the art of membrane technology is such that membrane separation cannot compete economically with other technologies with respect to the recovery of CO_2 from flue gases (Hendriks 1994). An optimal future gas absorption system probably combines the advantage of equipment compactness resulting from hollow fibre membranes and the advantage of process selectivity resulting from the chemical absorption process (Feron and Jansen 1998).

In low temperature distillation CO_2 is solidified in heat exchangers and then collected. The technology is probably only feasible on a small scale, for flue gas streams with high CO_2 concentration (Hendriks 1994).

Annex B CO$_2$ point sources in the Netherlands

C.N. Hamelinck (STS-UU) and G.J. Ruijg (ECN)

Table B-1. CO$_2$ point sources, with relevant details and resulting CO$_2$ cost at gate.

Location	Type	CO$_2$ stream (Mtonne CO$_2$/year)	Purity (volume % CO$_2$)	Annual load (hours)	Depreciation period (years)	CO$_2$ cost (€/tonne CO$_2$)
Sluiskil	Industrial process NH3	1,10	100%	8200	20	3,6
Europoort	Industrial process Per+ H2	1,00	100%	8200	20	3,7
Europoort	Industrial process NH3	0,50	100%	8200	20	3,9
Geleen	Industrial process NH3	0,50	100%	8200	20	3,9
Terneuzen	Industrial process EO	0,13	100%	8200	20	4,9
Moerdijk	Industrial process EO	0,10	100%	8200	20	5,1
Rotterdam	Industrial process H2	0,10	100%	8200	20	5,1
Geertruidenberg	PC boiler and other	5,87	14%	7977	18	36
Amsterdam	PC boiler	2,68	14%	7000	19	38
Europoort	AVI	1,11	13%	8000	20	39
Buggenum	IGCC	1,27	9%	8000	18	40
Nijmegen	AVI	0,28	13%	8000	20	42
Rotterdam	PC boiler	5,32	14%	7000	7	42
Eemshaven	Power Plant CC and conventional gas fired	4,20	4%	7500	15	42
Amsterdam	AVI	0,55	13%	8000	13	42
Moerdijk	AVI	0,45	13%	8000	14	42
Duiven	AVI	0,21	13%	8000	20	42
Assen	AVI	0,28	13%	8000	16	43
Alkmaar	AVI	0,29	13%	8000	15	43
Europoort	Industrial Steam Turbine	0,32	10%	7000	20	44
Hengelo	AVI	0,17	13%	8000	17	44
Terneuzen	Industrial CC	1,33	4%	7000	20	44
Delfzijl	Industrial CC	1,17	4%	7000	20	45
Rotterdam	AVI	0,07	13%	8000	20	46
Eerbeek	Industrial CC	0,72	4%	7000	20	46
Geleen	Industrial CC and industrial GT + boiler	0,70	4%	7000	20	46
Europoort	Industrial CC	0,67	4%	7000	20	46
Rotterdam	Power Plant CC	1,53	4%	5500	20	47
Europoort	Industrial CC and industrial GT + boiler	0,59	4%	7000	20	47
Borsele	PC boiler	1,78	14%	5844	7	47
IJmuiden	Power Plant CC	0,47	4%	8000	16	47
Hengelo	Industrial CC	0,47	4%	7000	20	48
Maastricht	Industrial ST	0,09	10%	7000	20	48
Helmond	AVI	0,22	13%	5000	20	48
Rotterdam	Industrial CC	0,59	4%	6500	20	48
Emmen	AVI	0,28	13%	5000	17	48
Nijmegen	PC boiler	2,40	14%	5680	6	48
Utrecht	Power Plant CC and conventional gas fired	1,42	4%	5000	20	48
Emmen	Industrial CC	0,65	4%	6000	20	49
Sluiskil	Industrial CC	0,34	4%	7000	20	49
Borculo	Industrial CC	0,34	4%	7000	20	49
Maastricht	Industrial CC	0,31	4%	7000	20	49
Bergen op Zoom	Industrial CC	0,25	4%	7000	20	50
IJmuiden	Industrial CC	0,24	4%	7000	20	50
Europoort	Industrial CC	0,22	4%	7000	20	51
Rotterdam	Industrial CC	0,21	4%	7000	20	51
Rotterdam	Power Plant CC and conventional gas fired	0,72	4%	5000	20	51
Ter Apel	Industrial CC	0,18	4%	7000	20	51
Dordrecht	AVI	0,06	13%	8000	11	51
Utrecht	Power Plant CC and conventional gas fired	0,57	4%	5000	20	52
Diemen	Power Plant CC	0,52	4%	5618	16	52
Den Haag	Power Plant CC	0,52	4%	5000	20	53
Wapenveld	Industrial CC	0,14	4%	7000	20	53
Arnhem	Industrial CC	0,14	4%	7000	20	53
Moerdijk	Industrial CC	0,14	4%	7000	20	53
Velsen	Conventional gas fired PP	1,91	10%	5000	6	53
Europoort	Industrial CC	0,13	4%	7000	20	53

Table B-1 continued. CO$_2$ point sources, with relevant details and resulting CO$_2$ cost at gate.

Location	**Type**	**CO$_2$ stream (Mtonne CO$_2$/year)**	**Purity (volume % CO$_2$)**	**Annual load (hours)**	**Depreciation period (years)**	**CO$_2$ cost (€/tonne CO$_2$)**
Delfzijl	Industrial CC	0,13	4%	7000	20	53
Europoort	Industrial GT + boiler	0,13	4%	7000	20	53
Moerdijk	Power Plant CC	0,65	4%	4941	17	53
Den Bosch	Industrial CC	0,16	4%	6500	20	53
Eindhoven	Industrial CC	0,11	4%	7000	20	54
Almere	Industrial CC	0,11	4%	7000	20	54
Europoort	Industrial CC	0,11	4%	7000	20	54
Veendam	Industrial CC and industrial GT + boiler	0,16	4%	6200	20	54
Europoort	Industrial GT + boiler	0,06	4%	8000	20	54
Europoort	Industrial CC	0,10	4%	7000	20	54
Ravenstein	Industrial GT + boiler	0,10	4%	7000	20	54
Wapenveld	Industrial CC	0,24	4%	5500	20	54
Arnhem	Industrial CC	0,09	4%	7000	20	55
Roermond	Industrial CC and industrial GT + boiler	0,09	4%	7000	20	55
Dordrecht	Industrial CC and industrial GT + boiler	0,09	4%	7000	20	55
Purmerend	Power Plant CC	0,28	4%	5000	20	56
Bergen op Zoom	Industrial CC	0,08	4%	7000	20	56
Delft	Industrial CC	0,07	4%	7000	20	56
Velsen	Industrial CC	0,07	4%	7000	20	56
Helmond	Industrial CC	0,07	4%	7000	20	56
Almere	Power Plant CC	0,26	4%	5000	20	56
Ede	Industrial CC	0,18	4%	5500	20	56
Groningen	Industrial CC	0,07	4%	7000	20	56
Europoort	Industrial CC	0,07	4%	7000	20	56
Harlingen	Industrial CC	0,16	4%	5500	20	57
Rotterdam	Industrial GT + boiler	0,06	4%	7000	20	57
Europoort	Industrial GT + boiler	0,04	4%	8000	20	57
Hengelo	Industrial GT + boiler	0,06	4%	7000	20	57
Enschede	Power Plant CC	0,23	4%	5000	20	57
Europoort	Industrial CC	0,06	4%	7000	20	57
Koog a/d Zaan	Industrial CC	0,06	4%	7000	20	57
Sas van Gent	Industrial CC	0,06	4%	7000	20	57
Arnhem	Industrial GT + boiler	0,06	4%	7000	20	57
Dordrecht	Industrial CC	0,05	4%	7000	20	58
Europoort	Industrial CC and industrial GT + boiler	0,05	4%	7000	20	58
Maastricht	Industrial CC	0,13	4%	5500	20	58
Nijmegen	Industrial CC	0,05	4%	7000	20	58
Gouda	Industrial CC	0,04	4%	7000	20	59
Arnhem	Industrial CC	0,11	4%	5500	20	59
IJmuiden	Industrial CC	0,04	4%	7000	20	59
Emmen	Industrial CC	0,04	4%	7000	20	59
Veghel	Industrial CC	0,04	4%	7000	20	59
Delfzijl	Industrial CC	0,04	4%	7000	20	59
Leeuwarden	Industrial CC	0,04	4%	7000	20	59
Leiden	Industrial CC	0,04	4%	7000	20	59
Emmen	Industrial CC	0,09	4%	5500	20	60
Leiden	Power Plant CC	0,27	4%	4000	20	61
Rotterdam	Industrial CC	0,06	4%	5500	20	63
Groningen	Industrial CC	0,06	4%	5200	20	64
Eindhoven	Industrial CC	0,09	4%	4000	20	68
Den Bosch	Industrial CC	0,08	4%	4000	20	69
Helmond	Industrial CC	0,07	4%	4000	20	70
Renkum	Industrial CC	0,07	4%	4000	20	71
Bergen op Zoom	Industrial CC	0,06	4%	4000	20	71
Rotterdam	Industrial GT + boiler	0,33	4%	2472	20	73
Europoort	Industrial CC	0,04	4%	4000	20	75
Rotterdam	Industrial CC	0,03	4%	4000	20	77
Harculo	Conventional gas fired PP	0,37	10%	2691	2	155
Lelystad	Conventional gas fired PP	0,66	10%	3321	1	205
Bergum	Conventional gas fired PP	0,53	10%	2000	1	303
Maasbracht	Conventional gas fired PP	0,30	10%	500	1	953

Figure B-1. CO_2 point sources and top Carboniferous in the Netherlands

Annex C Pipeline pressure drop

C.N. Hamelinck (STS-UU)

The method to calculate a suitable diameter for CO_2 transport is iterative. First a diameter d is taken and the resulting pressure drop is calculated. Depending on the result a new value for the diameter has to be tried. The pressure drop should be close to, but not larger than 10 bar. If the pressure drop is too large, the calculation is done again with a bigger pipe diameter. If the pressure drop is considerably smaller than 10 bar, the pipe diameter is probably too large, resulting in higher material and construction costs. The goal is to construct a pipe with an optimal diameter and an acceptable pressure drop.

First the annually transported tonnes of CO_2 are translated to cubic meters per second. The density ρ of CO_2 at transport conditions (10 °C and 75 bar) is 899 kg/m^3. From the transported volume of CO_2 and the chosen diameter now follows the axial velocity:

$$v = \frac{F}{\frac{1}{4}\pi d^2} \qquad \text{Equation C-1}$$

with v = axial velocity (m/s)
F = CO_2 flow (m^3/s)
d = diameter of pipe (m)

The behaviour of fluids is characterised by the dimensionless Reynolds number:

$$\mathrm{Re} = \frac{\rho \cdot v \cdot d}{\mu} \qquad \text{Equation C-2}$$

with Re = Reynolds number (-)
μ = dynamic viscosity at transport conditions = $8.22 \cdot 10^{-5}$ Pa.s

When Re < $2 \cdot 10^3$ then the flow is laminar. In laminar flow the friction factor f can be calculated from:

$$f = \frac{16}{\mathrm{Re}} \qquad \text{Equation C-3}$$

with f = friction factor (-)

In most cases Re will be larger than $2 \cdot 10^3$: the flow is turbulent. For determining the friction factor for turbulent flow, the relative roughness of the pipe is needed. This is the roughness of the pipe surface (0.0457 mm for commercial steel, Perry et al. 1987) divided by the pipe diameter. The friction factor can now be read from e.g. Figure 5-28 in Perry.

The pressure drop follows from:

$$\Delta p = 4 f \cdot \frac{1}{2} \rho v^2 \frac{l}{d} \qquad \text{Equation C-4}$$

with Δp = pressure drop (Pa)
l = length of pipe (m)

Annex D Inventory of ECBM potential - method

F. van Bergen and H. Pagnier (TNO-NITG)

A geological evaluation of potential regions in The Netherlands onshore, an estimation of the (producible) Gas-In-Place, and an estimation of the amounts of CO_2 that can be stored in coal seams is made by the Netherlands Institute of Applied Geoscience TNO (van Bergen et al. 2000). Supplementary laboratory experiments were executed in co-operation with the Aachen University of Technology.

Geology

The major part of the Dutch territory lies within the Northwestern European Coal Basin. The most important coal-bearing deposits in The Netherlands are the Upper Carboniferous (Westphalian A to Late Westphalian C) sequences. These are present throughout the major part of The Netherlands at various depths with total thickness up to 3000 m. Potentially every 10th meter in the Westphalian A and B sequences a coal horizon can be expected (Pagnier et al. 1987). From a geological point of view the Dutch coal basins are comparable to the Black Warrior Basin in Alabama (U.S.), which were deposited in a similar depositional setting.

Area selection

Areas that have potential for Enhanced Coalbed Methane Production are identified. Only those areas with top of the Carboniferous within 2000 m of depth, are considered. Below this depth the permeability of the coal seams will be too low for both CBM production and CO_2 injection and drilling costs too high. Based on this depth criterion four areas have been selected: the Zuid-Limburg area, the Peel area, the Zeeland area, and the Achterhoek area (Figure D-1). Of these four areas only the Zuid-Limburg area has been actively mined. Within the four areas fault-bounded blocks were determined using seismics. Extension of the coal seams is assumed to be continuous within these fault-bounded blocks. Blocks were defined, if possible, by fault throws of ca. 50 meter, based on available seismics and seismic resolution. In the Zeeland area, which is structurally a relatively stable area, there are only a few seismic lines available, therefore the area is taken as a whole.

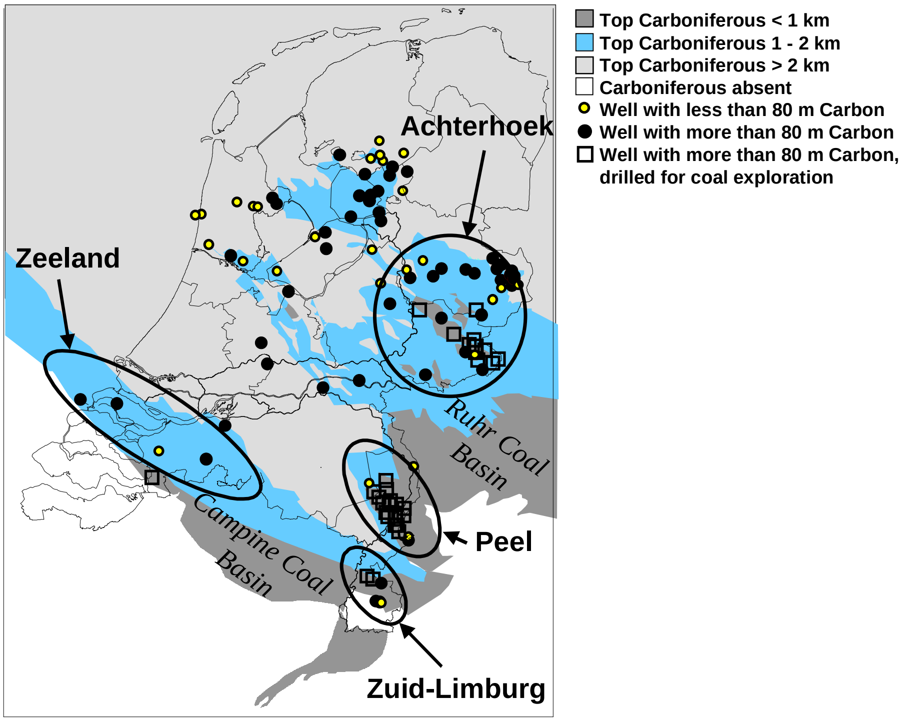


Figure D-1. Map of the top of the Carboniferous with selected wells for the inventory. All indicated wells have top Carboniferous not deeper than 2000m. Based on this map four areas have been selected and indicated on the map.

Coal thickness

The thickness of the coalbeds is of great importance for CBM and ECBM production, because thick coalbeds mean larger volumes and thus more gas; and because advanced producing techniques will be better applicable in thick coalbeds. The available data that can be used for the determination of the (thickness of the) coal seams are limited. The resolution of the seismic data is too low to be used for thickness evaluation of individual coal seams. The thickness information used in this study was mainly derived from exploration wells for oil, gas and coal. Only in the Zuid-Limburg area data from the old mining activities are available. Based on five wells drilled for a coal inventory study in the Achterhoek and the Zuid-Limburg areas, the mean thickness is known to be 1 m for coal seams (> 50cm), with a maximum of ca. 3.5 m.

The limited number of exploration wells for oil and gas reached the Carboniferous were evaluated for coal using geophysical well logs. For log interpretation, and especially for coal thickness evaluation, a recently developed statistical tool was applied, based on Bayesian statistics.

In-situ gas content

The major part of the methane in the coal is in the adsorbed phase. For this study only existing information and old coal samples are available, excluding direct measurements of the gas content of the coals. The gas content is estimated by indirect methods, using adsorption isotherms as main input data dependent on pressure, temperature and on coal characteristics.

The relation between pressure and gas sorption capacity (GSC) is generally assumed to follow a pressure dependent Langmuir isotherm:

$$G_c = \frac{(G_{LC} \times P)}{(P_{LC} + P)} \qquad \text{Equation D-1}$$

with: G_c = gas content of the coal (m^3 gas $_{stp}$ / tonne coal)

G_{LC} = Langmuir Volume, maximum gas adsorption capacity (m^3 gas $_{stp}$ / tonne coal)

P = Pressure (MPa)

P_{LC} = Langmuir Pressure (MPa)

The isotherm shows an increase of the GSC with increasing pressure, until a certain maximum is reached at high pressures (> 20Mpa). This behaviour reflects mono-layer adsorption on a surface, where the maximum represents the state of a completely covered surface that can not adsorb any more molecules.

It must be noted that the calculated gas content, given the in-situ reservoir pressure, is the maximum amount of gas that can be present in the coal seams under these conditions. However, the coals can be undersaturated (depleted) with methane due to degassing in geological history (Figure D-2). If this is the case the methane content is lower than calculated. To correct for a possible degassing in the geological past, burial history graphs of the different areas are constructed. For the Zuid-Limburg, the Peel, and the Achterhoek area corrections were made, using the paleo hydrostatic pressure (at the time of shallowest burial) for the calculations. The storage potential for CO_2 is independent of methane saturation; therefore the present-day hydrostatic pressure is used for calculation of CO_2 amounts.

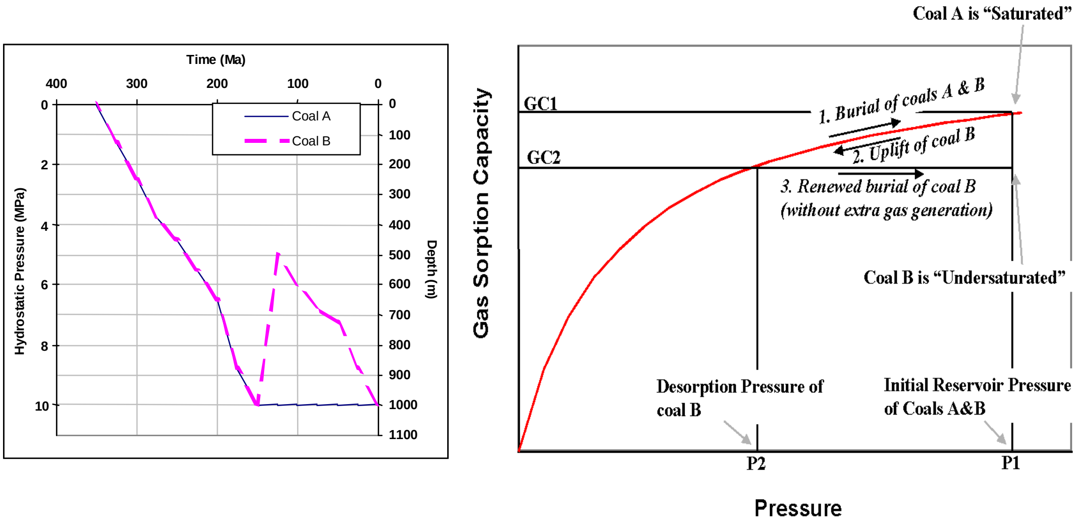


Figure D-2. Example of burial history graph (left) and example of sorption isotherm (in grey, right picture) for methane on coal. In the right figure the effect of pressure release (e.g. during a phase of tectonic uplift) is followed by an increase of pressure (e.g. during renewed subsidence). Thus results in an undersaturated coal according to the following scenario: Coals A and B are buried together to a certain depth with pressure P1. The gas content of both coals follows the adsorption isotherm until a gas content GC1 is reached. Coal A stays at this pressure and keeps gas content GC1. Coal B experiences an uplift event and desorps according to the adsorption isotherm until the end of the uplift phase (pressure P2). It is not likely that renewed burial to a depth with pressure P1 results in renewed gas generation therefore there is no supply of new gas. Coal B will keep a gas content of GC2 at pressure P1 and will be undersaturated. Conclusively, the burial history and the important coalification phases should be considered, e.g. via burial history modelling. (adapted from (McElhiney et al. 1993)).

With increasing temperature the GSC shows a reverse trend (e.g. Levy et al. 1997; Bustin and Clarkson 1998). Both pressure and temperature increase with depth and their opposed effects are superimposed on each other (Kim 1977), resulting in a maximum in GSC at a certain depth. Up to a depth of 2000 m, the effect of temperature increment will be negligible compared to the effect of pressure increment. However, at greater depths the temperature effect will become more and more important.

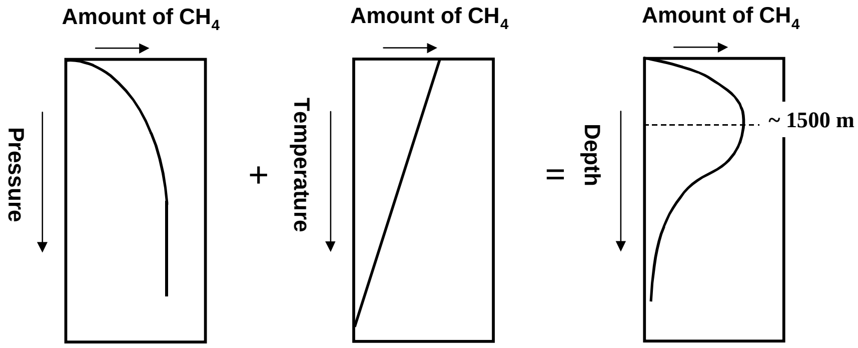


Figure D-3. Combined effect of pressure and temperature increase with increasing depth on the amount of methane, assuming normal geothermal gradient and hydrostatic pressure.

The coal characteristics that affect the GSC of coal are composition, rank, ash content and moisture content of the coal. These parameters are not independent, which makes it complex to define the impact of the parameters separately. Within the study an experimental program has been executed on old coal samples from the subsurface of The Netherlands, to establish generic relations between the GSC of pure CH_4, pure CO_2, and for mixtures of these gases versus the different variables. These relations need to be determined for areas with a similar geological history within a sedimentary basin. This experimental program is unique because involves experiments with pressures up to 20 MPa (200 Bar).

Exchange ratio between CBM and CO_2

The GSC of coal for CO_2 is assumed to be dependent on the same variables as the GSC for CH_4, as described above. The amount of CO_2 (in m^3) that can potentially be stored in the coal seams will be larger than the produced methane: based on experimental data from several authors (e.g. Puri and Yee

1990; Hall et al. 1994; Stevenson et al. 1991) it is generally assumed that 2 molecules of CO_2 replace one molecule of CH_4. The adsorption capacity of coal for supercritical CO_2 ($P > 0.74$ MPa) is probably much higher, possibly up to 5:1 at 12 MPa (Hall et al. 1994). The results of the high pressure laboratory experiments that were performed for this study could not give a definite exchange ratio: calculated Exchange ratios varied between 1.2:1 and 6.3:1 (Krooss et al. 2000). However, based on the literature and on our laboratory results, it is very likely that the adsorption capacity of coals, and therefore the ER, increases to some extent with increasing depth.

Calculations of Gas-In-Place and Storable amounts of CO_2

The calculated amounts of gas, both producible CH_4 and storable CO_2, are restricted to the potential of the coal layers in the Carboniferous deposits, additional potential of strata in between the coal (e.g. sandstones) is not taken into consideration. Further, the calculated amounts of gas are restricted to the amounts related to the adsorption capacity of the coal. The storage capacity of water-filled pores and of the cleat system of the coals is not included, because they have a marginal effect on the total calculated storage potential.

A generally accepted formula to calculate the Gas-In-Place (GIP) reserves is the following:

$$GIP = A \times h \times \rho_c \times G_c \qquad \text{Equation D-2}$$

with GIP = Gas-In-Place (10^6 $m^3{}_{stp}$)
A = area (km^2)
h = cumulative height of coal in the area (m)
ρ_C = density of the coal ($tonne/m^3$)
G_c = gas content of the coal (m^3 gas_{stp} / tonne coal), see equation D-1

The amount of CH_4 that can be produced from the coal seams is described by:

$$PGIP = GIP \times C \times R \qquad \text{Equation D-3}$$

with PGIP = Producible-Gas-In-Place (10^6 m^3)
C = completion factor (-)
R = recovery factor (-)

The completion factor is an estimation of the part of the net cumulative coal thickness within the drilled strata that will contribute to the gas production. The completion factor therefore strongly depends on the thickness of the separate coal seams and the distance between the coal seams. Depending on the application of stimulation techniques and the costs that come with it the completion factor can be increased.

The recovery factor is the amount of gas that can be produced from a contributing coal seam. In conventional CBM production this depends strongly on the pressure drop that can be realised by pumping of large volumes of water. The production of CBM by conventional methods is often inefficient: normally only about 20% to 60% of original GIP can be recovered. With the process of ECBM with gas injection the recovery can be increased, theoretically up to 100 % (Stevens and Pekot 1999).

The amount of CO_2 that can be stored is calculated by the following equation:

$$CO_2S = PGIP \times ER \times \rho_{CO2} \times 10^{-9} \qquad \text{Equation D-4}$$

with: CO_2S = amount of CO_2 to be stored, Mtonnes;
PGIP = Producible-Gas-In-Place, 10^6 $m^3{}_{stp}$;
ER = exchange ratio of CO_2 for methane;
ρ_{CO2} = density of CO_2, 1.8 $kg/m^3{}_{stp}$;

Monte Carlo simulation

Monte Carlo simulation analysis is applied to take into account the uncertainties in the values of the parameters. This analysis allows, in a probabilistic manner, the prediction of the expected average PGIP and the expected amount of CO_2 to be stored and their distribution of reserves. Triangular distributions (with a minimum, median, and maximum) are used for G_{LC}, P, P_{LC}, h, ρ_C, C, R, ER, and fixed values for A and ρ_{CO2}. The values for the variables vary per area.

Table D-1. Summary of Monte Carlo simulation analysis input values for Block 4 in the Zuid-Limburg area (4.2 km^2).

			Minimum	**Median**	**Maximum**
Interval independent	ρ_C	Density of coal	1250	1300	1600
	G_{LC}	Langmuir Volume	10	15	25
	P_{LC}	Langmuir Pressure	2.5	5	10
	C	Completion factor	0.4	0.5	0.9
	R	Recovery factor	0.2	0.4	0.85
200-600 m	h	Net cum. coal thickness	1	2	5
	P	Pressure	2.1	4.1	6.2
	ER	Exchange Ratio	1.5	2	2.2
600-1000 m	h	Net cum. coal thickness	6	10	14
	P	Pressure	6.2	8.2	10.3
	ER	Exchange Ratio	1.5	2	2.2
1000-1500 m	h	Net cum. coal thickness	6	10	14
	P	Pressure	10.3	12.9	15.5
	ER	Exchange Ratio	2	2.5	3.5

Results

All areas and fault-bounded blocks, as defined in the area selection, are evaluated using Monte Carlo simulation analysis. Typical results of the analysis per block are probability curves (Figure D-4).

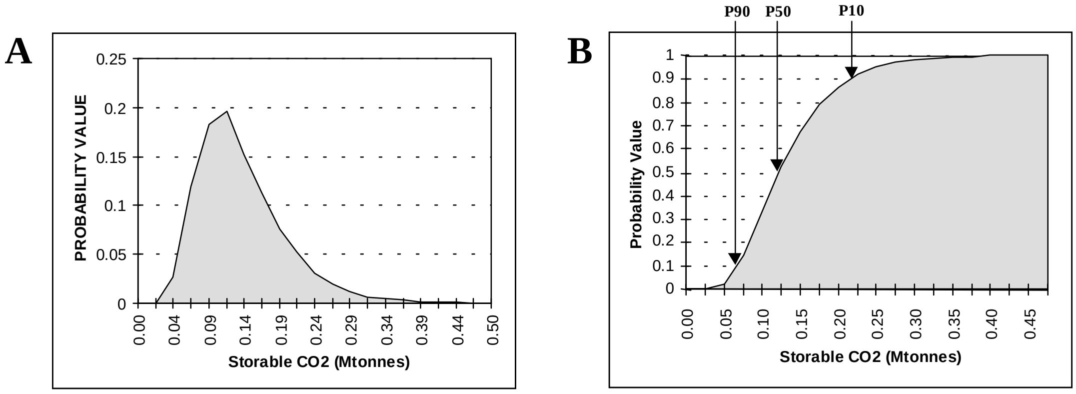


Figure D-4. Results of the Monte Carlo Analysis of the 600-1000m interval of Block 4 in the Zuid-Limburg area a) Probability curve and b) cumulative probability curve of CO_2 storage potential. The reserve estimations indicated at P90, P50 and P10 give respectively an increasing uncertainty in the reserve estimation of 10, 50, and 90%.

The results per area are presented in Table D-2 and Figure D-5, while the calculated results per block are given in the appendix. The results show that the potential of the coals between 1500 m and 2000 m depth is larger than the shallower coals. This is due to the larger amount of coal in this interval and the increased pressure. It must be noted that a negative temperature effect is not taken into consideration, although this effect is probably significant in the interval between 1500 and 2000 m. However, the use of the coals in this interval is (currently) technically and economically questionable.

Table D-2. Gas content (billion m^3 gas) and storable CO2 (Mtonnes) of the Peel, Zeeland, Zuid-Limburg, and Achterhoek area up to a depth of 1500 m. The GIP and PGIP of the Peel, Zuid-Limburg, and Achterhoek area are corrected according to their burial history.

Area	**Total area (km^2)**	**Interval (m)**	**GIP**			**PGIP**			**Theoretical CO2 storage**			**CO2S**		
			P10	**P50**	**P90**	**P10**	**P50**	**P90**	**P10**	**P50**	**P90**	**P10**	**P50**	**P90**
Peel	536	< 1500	19	42	73	5	11	23	130	284	491	31	76	156
Zuid-Limburg	48	< 1500	5	9	15	1	3	5	26	47	78	6	13	25
Achterhoek	3796	< 1500	12	80	275	3	21	80	64	436	1500	17	116	431
	3796	1500-2000	25	169	587	7	46	176	143	936	3232	36	249	938
Zeeland	2346	1500-2000	177	417	726	45	113	233	898	2119	3790	214	561	1184
Total		< 1500	36	131	364	9	35	109	220	767	2069	54	205	612
		1500-2000	202	586	1312	52	159	409	1041	3055	7022	250	810	2122

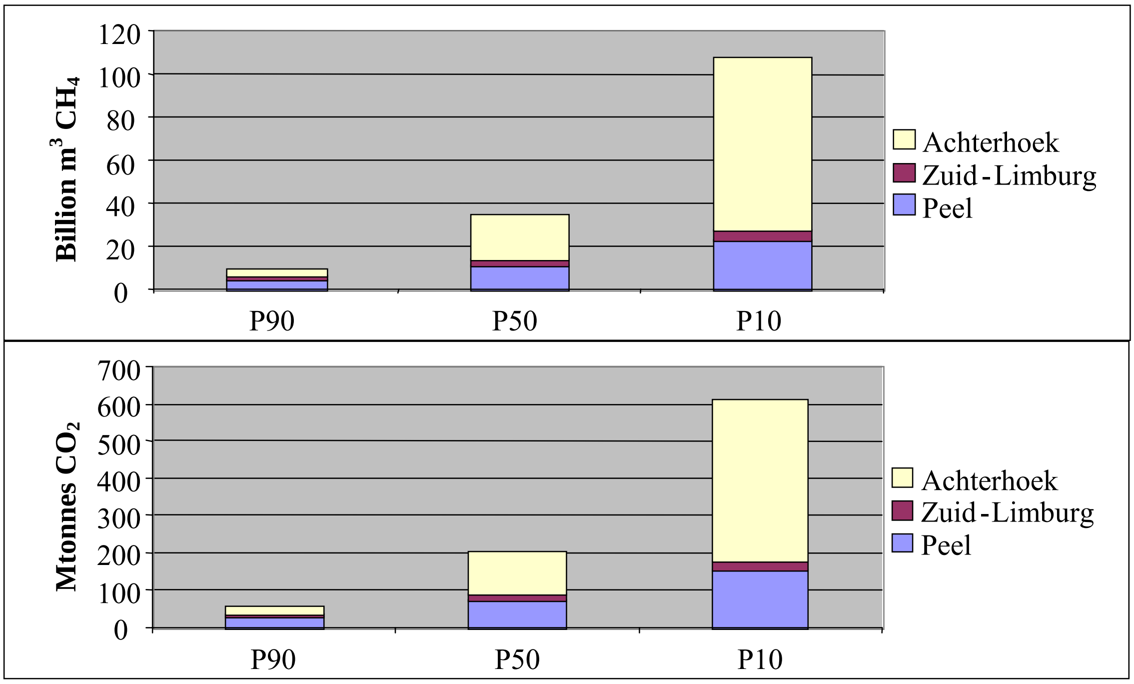


Figure D-5. Potential Producible CH_4 and storable CO_2 in coal seams in the Netherlands. The values are for the total areas, up to a depth of 1500m.

Evaluation

A comparison with an earlier inventory of in-situ CBM reserves (Wolf et. al, 1997) with the P50 results of this study shows, as expected, differences. These differences can be explained by the different methodology used and difference in areas. For the Zuid-Limburg area, however, is more than a factor two. This seems to be due to the higher gas contents that were used by Wolf et al. (1997), who followed the estimates of Stuffken (1957). However, Stuffken indirectly estimated the gas concentration of coal by correlating the methane content of mine ventilation air to the tonnes of coal that were produced from the mine. In our opinion, this introduces many uncertainties to the absolute methane concentrations, and we therefore think that it is better to use the concentrations based on the Langmuir curves.

Table D-3. Comparison of results of the P50 GIP value of this study with the estimations of Wolf et al. (1997), gas contents in billion m^3.

	Interval	**This study**		**Wolf et al.**	
Area	**(m)**	**Total area**	**P50 GIP**	**Total area**	**Estimated total gas**
Peel	< 1500	536	42	194.2	10.1
Zuid-Limburg	< 1500	48	9	67.4	25.8
Achterhoek	< 1500	3796	80	594	29.1
	1500-2000	3796	169	2300	140
Zeeland	1500-2000	2346	417	2250	408.5

The Zuid-Limburg area (Blocks 3, 4, and 5) has the highest estimated (producible) methane content per km^2, thus the highest estimated storage potential per km^2 for CO_2. Considering the total available surface per area, the Achterhoek area (Block 2) has the highest estimated potential for (producible) methane contents, and thus the highest estimated total storage potential for CO_2. However, the uncertainties in this latter area are also the highest. This implies that the Zuid-Limburg area is probably the best location for a test site, whereas the Achterhoek area probably has more potential for large scale CO_2 sequestration. Block 3 of the Peel area probably is a good intermediate, with fairly high methane content and an intermediate sized area. However, the choice of an area for a test site will also strongly depend on several local parameters, which are not considered within the scope of this study. Within the context of this study, a validation of the results can only be executed with a conditioned test site.

The results of this study together with the other studies within this project will help to make a decision for a future test site.

Annex E Inventory of ECBM potential – results

F. van Bergen and H. Pagnier (TNO-NITG)

Table E-1. Relative gas content (in million m^3 gas/km^2) and storable CO$_2$ (in Mtonnes/km^2) of the defined blocks in the Peel, Zeeland, Zuid-Limburg, and Achterhoek area up to a depth of 1500 m. The GIP and PGIP of the Peel, Zuid-Limburg, and Achterhoek area are corrected according to their burial history.

Area	**Block**	**Interval**	**GIP**			**PGIP**			**Theoretical CO$_2$ storage**			**CO$_2$S**		
			P90	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Peel	1	700-950	2.73	6.76	13.59	0.66	1.82	4.19	0.05	0.11	0.19	0.01	0.03	0.06
	1	950-1200	10.39	24.41	43.34	2.55	6.58	13.82	0.08	0.17	0.31	0.02	0.05	0.10
	1	1200-1500	13.63	30.80	51.75	3.32	8.34	16.68	0.09	0.20	0.34	0.02	0.05	0.11
	2	700-950	3.48	8.29	15.26	0.88	2.26	4.83	0.04	0.09	0.15	0.01	0.02	0.05
	2	950-1200	8.40	20.26	37.11	2.06	5.55	11.97	0.06	0.13	0.25	0.01	0.04	0.08
	2	1200-1500	8.01	22.07	46.09	2.01	5.91	14.10	0.05	0.14	0.29	0.01	0.04	0.09
	3	700-950	10.84	25.81	47.42	2.62	6.96	15.05	0.10	0.22	0.39	0.02	0.06	0.12
	3	950-1200	15.70	37.56	66.23	3.96	10.16	21.14	0.10	0.24	0.41	0.02	0.06	0.13
	3	1200-1500	19.47	45.84	81.41	4.86	12.47	26.14	0.13	0.28	0.51	0.03	0.07	0.16
	4	700-950	6.36	14.91	26.02	1.56	3.97	8.38	0.05	0.12	0.20	0.01	0.03	0.07
	4	950-1200	9.08	22.02	40.23	2.29	5.96	12.75	0.06	0.13	0.25	0.01	0.04	0.08
	4	1200-1500	3.36	12.02	27.75	0.88	3.18	8.45	0.02	0.07	0.17	0.01	0.02	0.05
	5	700-950	6.53	15.03	25.66	1.61	4.02	8.33	0.04	0.10	0.16	0.01	0.03	0.05
	5	950-1200	7.65	17.92	29.57	1.87	4.72	9.46	0.04	0.10	0.16	0.01	0.03	0.05
	5	1200-1500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	6	700-950	14.54	23.85	38.31	3.35	6.61	12.56	0.12	0.19	0.30	0.03	0.05	0.10
	6	950-1200	17.14	39.54	65.40	4.22	10.53	21.03	0.10	0.24	0.39	0.03	0.06	0.13
	6	1200-1500	8.09	18.53	31.76	2.00	4.98	10.20	0.05	0.11	0.19	0.01	0.03	0.06
	7	700-950	24.29	39.13	61.16	5.59	10.75	20.37	0.23	0.32	0.44	0.05	0.09	0.15
	7	950-1200	11.11	25.75	43.78	2.78	6.98	14.12	0.07	0.16	0.27	0.02	0.04	0.09
	7	1200-1500	11.84	27.22	44.62	2.93	7.33	14.70	0.07	0.16	0.27	0.02	0.04	0.09
	8	700-950	25.77	41.94	66.11	5.92	11.39	21.64	0.25	0.34	0.47	0.05	0.09	0.16
	8	950-1200	4.13	9.59	16.78	1.00	2.59	5.42	0.03	0.06	0.10	0.01	0.02	0.03
	8	1200-1500	11.83	27.37	45.10	2.87	7.30	14.57	0.07	0.17	0.27	0.02	0.04	0.09
	9	700-950	6.67	16.10	30.82	1.60	4.35	9.76	0.06	0.13	0.23	0.01	0.04	0.07
	9	950-1200	8.31	19.42	33.91	2.01	5.20	10.86	0.05	0.12	0.20	0.01	0.03	0.07
	9	1200-1500	5.44	16.70	37.14	1.35	4.57	11.58	0.03	0.10	0.23	0.01	0.03	0.07
	10	700-950	24.83	36.68	54.48	5.58	10.10	18.19	0.22	0.30	0.42	0.05	0.08	0.14
	10	950-1200	44.56	63.54	89.70	9.87	17.49	30.26	0.28	0.39	0.54	0.06	0.11	0.18
	10	1200-1500	10.58	24.65	42.58	2.65	6.52	13.51	0.07	0.15	0.26	0.02	0.04	0.08
	11	700-950	37.79	54.68	78.12	8.46	14.99	26.51	0.22	0.30	0.42	0.05	0.08	0.14
	11	950-1200	40.74	56.71	78.27	8.93	15.64	26.89	0.21	0.30	0.42	0.05	0.08	0.14
	11	1200-1500	11.61	26.50	45.49	2.82	7.13	14.63	0.06	0.15	0.25	0.02	0.04	0.08
	12	700-950	8.58	21.34	41.56	2.11	5.80	12.86	0.08	0.18	0.31	0.02	0.05	0.10
	12	950-1200	8.39	19.23	33.84	2.06	5.20	10.73	0.05	0.12	0.20	0.01	0.03	0.06
	12	1200-1500	7.54	19.47	38.97	1.84	5.23	12.14	0.04	0.12	0.24	0.01	0.03	0.07
Zeeland		1500-2000	75.59	177.63	309.36	19.07	47.97	99.24	0.38	0.90	1.62	0.09	0.24	0.50
Zuid-Limburg	1	200-600	2.32	5.82	11.37	0.58	1.58	3.56	0.02	0.05	0.08	0.00	0.01	0.03
	1	600-1000	14.45	39.33	82.27	3.55	10.55	25.61	0.06	0.16	0.34	0.01	0.04	0.11
	1	1000-1500	44.34	109.36	219.17	10.79	29.95	68.12	0.23	0.57	1.15	0.05	0.15	0.35
	2	200-600	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2	600-1000	17.63	40.46	70.99	4.25	10.90	22.37	0.10	0.22	0.38	0.02	0.06	0.12
	2	1000-1500	27.53	63.77	110.06	6.69	17.00	34.98	0.15	0.36	0.63	0.04	0.10	0.20
	3	200-600	2.55	8.00	17.73	0.66	2.20	5.45	0.03	0.08	0.15	0.01	0.02	0.05
	3	600-1000	58.50	89.14	131.27	13.41	24.31	43.91	0.25	0.38	0.56	0.06	0.10	0.18
	3	1000-1500	60.32	137.75	234.32	14.74	36.98	74.51	0.31	0.73	1.26	0.08	0.19	0.40
	4	200-600	5.80	11.35	21.25	1.42	3.14	6.66	0.05	0.08	0.14	0.01	0.02	0.04
	4	600-1000	74.16	108.99	159.18	16.91	30.13	53.43	0.30	0.45	0.64	0.07	0.12	0.22
	4	1000-1500	97.46	142.22	201.74	22.02	39.20	67.98	0.50	0.73	1.06	0.11	0.20	0.36
	5	200-600	8.46	14.96	25.90	2.02	4.20	8.47	0.05	0.08	0.14	0.01	0.02	0.04
	5	600-1000	79.27	114.96	166.67	17.87	31.65	55.12	0.30	0.45	0.65	0.07	0.12	0.22
	5	1000-1500	100.37	145.39	205.55	22.66	40.08	69.47	0.50	0.73	1.07	0.11	0.20	0.36
	6	200-600	0.08	0.49	1.54	0.02	0.13	0.46	0.01	0.03	0.06	0.00	0.01	0.02
	6	600-1000	11.37	27.55	51.98	2.89	7.54	16.30	0.08	0.18	0.30	0.02	0.05	0.10
	6	1000-1500	32.55	74.39	128.46	8.00	19.87	41.09	0.19	0.43	0.75	0.04	0.12	0.24

Table E-1 continued. Relative gas content (in million m3 gas/km2) and storable CO_2 (in Mtonnes/km2) of the defined blocks in the Peel, Zeeland, Zuid-Limburg, and Achterhoek area up to a depth of 1500 m. The GIP and PGIP of the Peel, Zuid-Limburg, and Achterhoek area are corrected according to their burial history.

Area	Block	Interval	GIP			PGIP			Theoretical CO_2 storage			CO_2S		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Achterhoek	1	850-1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	1	1000-1500	1.22	8.10	28.41	0.34	2.26	8.34	0.01	0.04	0.15	0.00	0.01	0.04
	1	1500-2000	11.25	75.08	258.14	2.97	20.79	78.04	0.06	0.38	1.38	0.02	0.10	0.39
	2	850-1000	1.43	9.66	34.10	0.37	2.66	10.25	0.01	0.04	0.15	0.00	0.01	0.04
	2	1000-1500	12.72	86.59	296.15	3.24	22.90	85.90	0.07	0.47	1.62	0.02	0.12	0.46
	2	1500-2000	8.64	58.08	198.96	2.33	16.26	59.82	0.05	0.32	1.12	0.01	0.08	0.33
	3	850-1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3	1000-1500	2.29	15.65	53.47	0.62	4.25	16.05	0.01	0.08	0.29	0.00	0.02	0.08
	3	1500-2000	3.50	24.31	83.19	0.99	6.54	24.62	0.02	0.13	0.44	0.00	0.03	0.13
	4	850-1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	4	1000-1500	3.80	26.53	94.42	0.99	6.87	27.91	0.06	0.36	1.19	0.01	0.09	0.36
	4	1500-2000	8.27	55.42	198.96	2.17	15.28	58.44	0.06	0.39	1.35	0.02	0.10	0.40
	5	850-1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	1000-1500	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	1500-2000	7.01	46.60	160.82	1.79	12.44	46.49	0.03	0.24	0.82	0.01	0.06	0.25
	6	850-1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	6	1000-1500	0.23	1.54	5.37	0.06	0.41	1.58	0.00	0.01	0.03	0.00	0.00	0.01
	6	1500-2000	6.02	40.61	142.28	1.63	11.14	42.85	0.04	0.23	0.78	0.01	0.06	0.23

Table E-2. Absolute gas content (in million m^3 gas) and storable CO_2 (in Mtonnes/km^2) of the defined blocks in the Peel, Zuid-Limburg, and Achterhoek area up to a depth of 1500 m. The GIP and PGIP of the Peel, Zuid-Limburg, and Achterhoek area are corrected according to their burial history.

Area	Block	Block Area	GIP			PGIP			Theoretical CO_2 storage			CO_2S		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Peel	1	58.30	1560	3613	6336	381	975	2022	12.23	28.36	48.87	3.02	7.59	15.59
	2	101.40	2016	5133	9985	502	1391	3134	14.57	36.69	69.84	3.65	9.82	21.83
	3	152.10	6998	16610	29670	1742	4502	9480	49.54	113.35	198.05	11.59	29.97	62.53
	4	34.00	639	1664	3196	161	446	1006	4.43	11.03	20.82	1.09	2.96	6.59
	5	18.30	260	603	1011	64	160	326	1.61	3.65	6.01	0.39	0.97	1.94
	6	67.90	2700	5562	9198	650	1502	2973	18.66	36.96	60.14	4.47	9.93	19.43
	7	4.20	198	387	628	47	105	207	1.57	2.69	4.10	0.36	0.73	1.36
	8	5.60	234	442	717	55	119	233	1.92	3.17	4.76	0.44	0.86	1.57
	9	46.00	939	2402	4686	228	649	1481	6.48	16.21	30.48	1.61	4.34	9.58
	10	14.00	1119	1748	2615	254	478	867	7.83	11.76	17.18	1.72	3.22	5.74
	11	16.80	1514	2317	3392	339	634	1143	8.29	12.63	18.39	1.85	3.45	6.18
	12	17.10	419	1027	1956	103	277	611	2.92	7.02	12.80	0.72	1.90	4.02
Zuid-Limburg	1	9.09	555	1405	2844	136	382	884	2.76	7.06	14.33	0.67	1.89	4.40
	2	3.03	137	316	549	33	85	174	0.75	1.75	3.06	0.19	0.47	0.98
	3	8.26	1002	1940	3166	238	524	1023	4.92	9.83	16.25	1.16	2.62	5.22
	4	9.18	1629	2410	3508	370	665	1176	7.79	11.61	16.89	1.73	3.16	5.68
	5	8.08	1520	2225	3217	344	613	1075	6.86	10.21	15.04	1.54	2.78	5.00
	6	10.74	473	1100	1954	117	296	621	3.02	6.89	11.94	0.71	1.84	3.78
Achterhoek	1	167.68	205	1358	4764	56	379	1398	1.08	6.99	24.62	0.26	1.90	7.25
	2	717.57	10152	69068	236973	2590	18339	68994	54.26	369.02	1266.08	13.87	97.92	362.06
	3	343.03	785	5369	18340	212	1458	5507	4.16	28.71	100.09	1.13	7.65	28.94
	4	33.66	128	893	3178	33	231	940	1.88	12.08	40.16	0.46	3.19	12.28
	5	262.80	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
	6	2271.1	532	3499	12203	131	934	3597	3.09	19.38	69.51	0.79	5.25	19.99

Table E-3. Absolute gas content (in million m^3 gas) and storable CO_2 (in Mtonnes/km^2) of the defined blocks in the Zeeland and Achterhoek area between 1500 and 2000 m. The GIP of the Achterhoek area is corrected according to its burial history.

Area	Block	Block Area	GIP			PGIP			Theoretical CO_2 storage			CO_2S		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Zeeland	1	2346	177342	416723	725767	44748	112532	232822	898.00	2118.71	3789.52	213.60	560.66	1183.77
Achterhoek	1	167.68	1886	12588	43284	499	3486	13086	9.50	64.23	231.72	2.57	17.41	65.46
	2	717.57	6201	41679	142765	1672	11666	42926	33.32	227.78	805.27	9.26	60.66	233.90
	3	343.03	1202	8338	28537	341	2243	8445	6.92	44.06	152.58	1.62	11.82	45.59
	4	33.66	278	1866	6698	73	514	1967	1.92	13.13	45.45	0.51	3.53	13.39
	5	262.80	1841	12247	42264	470	3270	12218	9.19	61.98	216.00	2.45	16.92	65.08
	6	2271.1	13666	92233	323142	3700	25304	97322	81.93	525.26	1781.43	19.93	138.32	515.01

Annex F CH$_4$/CO$_2$ replacement – Laboratory experiments

K-H. Wolf, O.H.M. Barzandji and H. Bruining (TUD)

At Delft University of Technology – Section of Applied Earth Sciences, scaled laboratory experiments are performed in an experimental High Pressure/Temperature device and the results are used in reservoir simulations. The research was emphasised on the relations between coal permeability, geo-stresses and CH_4 replacement by CO_2.

The ECBM-process is based on the strong adsorption affinity of coal for carbon dioxide, here enabling methane to be replaced by this greenhouse gas. It is claimed that early carbon dioxide breakthrough, often experienced in enhanced oil recovery, will be absent due to the strong sorption behaviour of carbon dioxide on coal (Gunter et al. 1997). A two to one coal-sorption-selectivity for carbon dioxide over methane gives room for thinking about zero greenhouse gas emission power plants. In the ideal situation, all the injected carbon dioxide stays sequestered on the internal coal surface in the deep, relatively undisturbed, sub-surface.

Present state of knowledge

In this field the book of van (van Krevelen 1993) is considered a handbook for coal typology, physics, chemistry and constitution. An extensive of coal in relation with other material can be found in “Chemistry of coal utilisation” by Elliot (1981). Experimental evidence of the potential of the ECBM-technique on coal samples was, among others, delivered by (Fulton et al. 1980). In his experiments, coal samples from the Pricetown mine in West Virginia were saturated with methane and thereafter exposed to carbon dioxide in a pressure vessel for several days. The methane production was encouraging. Extended experiments to higher carbon dioxide pressures (up to 55 bar) were done by (Reznik et al. 1982). They showed that carbon dioxide is capable of completely replacing in-situ methane from coalbeds by cyclic injection. Most relevant for the replacement of methane by carbon dioxide is probably the study done by (Arri et al. 1992) dealing with binary gas sorption. They show that an extended Langmuir isotherm can serve as a proper relation to predict the amounts of carbon dioxide and methane sorption on coal as a function of the free gas composition and pressure. They used a moist Fruitland coal sample from the San Juan Basin of Colorado and found a separation factor of 2.63 for sorbed methane and carbon- dioxide.

Amoco experimented with enhanced gas recovery from coals in the United States (1993) and first nitrogen, followed by carbon dioxide, were used as the injection gases. Meridian started a pilot plant for ECBM-production from coals in the San Juan Basin - United States (1995). It resulted into an increased methane production and no carbon dioxide breakthrough (Stevens et al. 1998). Bond (1967) already described the flow through the coal fractures system and the principle of diffusion in the micro-porous media, together with the occurring side effects. The complex natural fracture system, its origin and development, is covered by (Pattison et al. 1996). New visions on image analysis techniques to describe the spatial characteristics of a coal cleat system, are used by (Brande et al. 1999). A relation between the coal cleat network and the permeability was derived by (Chen and Harpalani 1995).

The first studies for ECBM using CO_2, particularly for the Dutch and Belgian Carboniferous of the Campina Basin and the adjacent areas, showed that the deeper sub-surface could hold considerable amounts of methane gas. Literature already shows that coal methane behaviour is related to stress relief during excavation, mostly from one or more seams in a gallery or a gallery system. The conclusions are used for a study on enhanced CBM production from improved production wells (Wolf et al. 1997). This information on depths, temperatures, associated geopressures and related permeabilities, are indirectly applicable to injection and production of respectively CO_2 and $CH_4 + H_2O$ in current reservoir models. American data show that the classical way of CBM-production is technically feasible up to a depth of about 1600 m. At greater depths very low permeabilities (Figure F-3), among other things due to plastic behaviour, could create serious production and injection problems. Results of the CBM demonstration project in Peer-Belgium confirm the assumption that at differential pressures, up to about 4 MPa, the permeabilities of coal can be relatively high (Wenselaers et al. 1996). However, one has to realise that the process of CO_2 injection and enhanced CH_4 production will be time consuming. For a maximum CO_2-injection, a maximum of methane and water has to be replaced. Therefore, simulations and large-scale laboratory experiments are running to characterise coal, flow and sorption behaviour.

Objectives of this study

Figure F-1 shows the structure of the work, and the interrelation between the subjects. Several objectives are to be met, to get a view on the reservoir characteristics of coal seams:

- The assessment of the effect of water in coal during the CO_2-enhanced coalbed methane process.
- The identification of effects of stress on coal-cleat porosity and permeability.
- The perception to characterise a natural fracture network of coal.

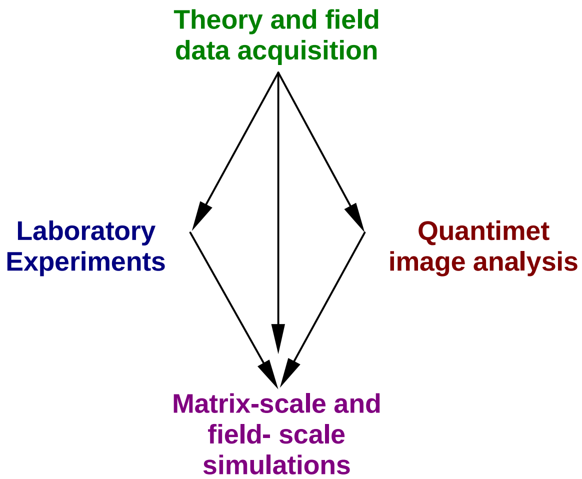


Figure F-1. The structure of the research programme.

To reach these objectives various CO_2-flushing experiments on wet and dry coals are performed. Additionally the coal fracture network is measured with image analysis. These results, together with literature outcomes, are applied in the model development for flow simulations. In a commercial setting at field-scale the idealised ECBM-process has an injection well for carbon dioxide injection into the coal layer and a production well for methane production. In the coal layer three zones are recognised (Figure F-2):

1. a CO_2 saturated zone,
2. a mixing zone, and,
3. a CH_4 and water/moisture bearing zone.

Due to the size of the coal samples, the laboratory experiments represent the transition area between the mixing zone, starting with majorly H_2O and CH_4, transferring to CH_4, H_2O and CO_2 and ending with CO_2 and the remaining H_2O.

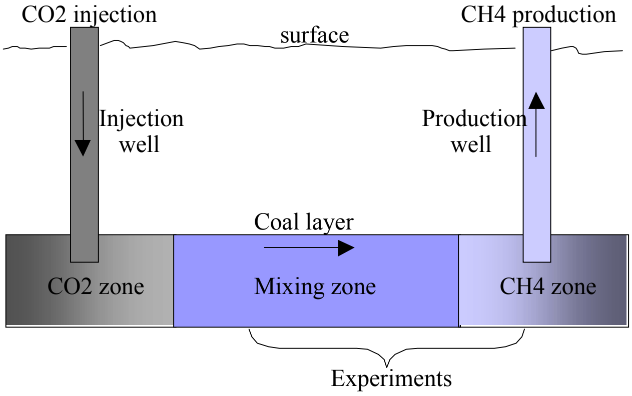


Figure F-2. The CO_2-enhanced CBM-process in the field.

Geo-environmental conditions

So far the applied reservoir conditions are adapted to the quality of the experimental set-up and the geo-environmental settings, as can be expected at the shallow south border of the Netherlands with Belgium and the Southeast border with Germany (less than ~700 m depth). The predicted and extreme geo-environmental properties are:

1. A maximum depth of 2000 meter, with a related temperature, lithostatic, and hydrostatic (pore) pressure of respectively, ~70°C, 35 MPa and 200 bar,
2. A net multi-seam thickness of 7 m. Seams with a maximum thickness of 2 m are included.
3. The coal pores contain a methane content up to 20 m^3/ton and a water saturation varying from nearly dry to fully saturated,
4. The cleat spacing and angle is varying per region and related to the tectonical and burial history,
5. The lateral extension is related to sub-horizontal tilted blocks (tilt<20°) of km^2-scale.

Knowing these parameters, it is possible to describe a coal seam as a reservoir consisting of different series of "matrix" pores and "cleat" parallel plates.

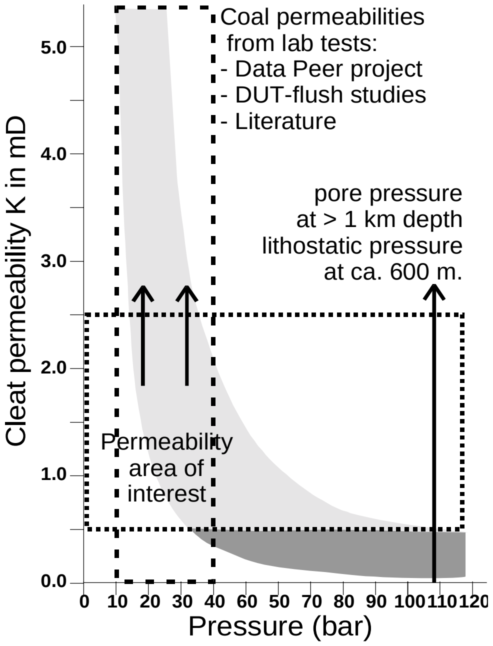


Figure F-3. Permeability as a function of pressure, of various Campian coal samples. The window shows the area of interest. (after Wolf et al., 2000).

Laboratory experiments and simulations

CH_4/CO_2 sorption studies on pulverised coal samples give a coal-specific P,T-sorption result of the behaviour of the coal matrix (macerals). Yet a coal texture includes the matrix, the cleat system and an ash component, and the latter are neglected. About two and a half years ago long term scaled P,T-experiments started on cylindrical samples, which contain both a coal matrix and a representative cleat system. The core samples are of a size that agrees with the reservoir conditions of a coal seam (Figure F-4). The tests are done on:

- water free and fully water saturated coals,
- either gas, liquid or super critical CO_2, and,
- at pore pressures up to about 80 bar.

The experiments give answers on the coal and coal-gas behaviour on shallow depths of usually ~700 m to partly ~800 m. In addition to these high P,T-flow experiments, image analysis methods are used to quantify the spatial dimensions of a coal cleat system. The core samples are of a size and origin that agrees with the reservoir coal seams of 2 meter or thinner. Measured are:

- the orientation angles between the different cleat groups,
- the variation in cleat sizes, based on grain particle width and breadth, and,
- the spacing between the major and minor fracture systems.

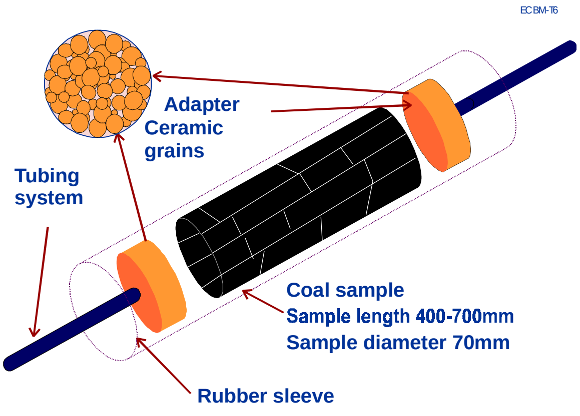


Figure F-4. Core holder of a methane and water saturated coal sample for flushing experiments with carbon dioxide.

The lab results and estimated geo-parameters are used for simulations on both micro-scale and on field scale. On micro-scale the laboratory CO_2 flush experiments are simulated in a specially developed program in which the replacement of methane and water by carbon dioxide are calculated and visualised. The results show a dual porosity system consisting of cleats and maceral pores. Diffusion-sorption in the matrix and Darcy-flow in the cleats represent flow. At field scale a reservoir simulator (STARS) is adapted for calculating the effects of CO_2-injection on methane and water production. Here the seams are represented as fractured low permeable reservoirs in which Darcy-flow is the mechanism for gas/fluid replacement.

Laboratory settings

As mentioned, the geo-environmental requirements are only partly met in the experimental setting. Figure F-5 shows a general outline of the set-up, Table F-1 gives the environmental parameters for a series of experiments. It consists of a high-pressure reactor, which can give a maximum annular gas pressure of 110 bar and in which the coal is placed. An inner cylinder of synthetic rubber contains the specimen with connecting ceramic end pieces.

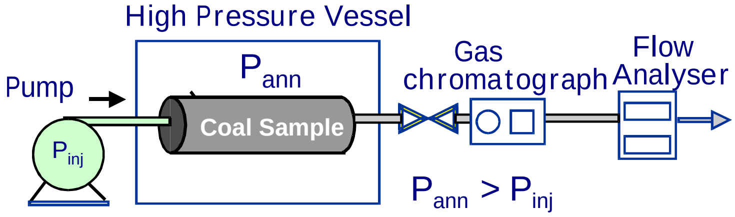


Figure F-5. Experimental setting for flushing experiments of methane (and water) saturated coals with carbon dioxide.

The maximum length and diameter of the sample are respectively 800 mm and 75 mm. Normally the samples are respectively about 250 mm by 72 mm. The inner cylinder is connected with fixed and movable steel tubing with the inlet and exhaust of the reactor and displacement transducers, to measure volumetric changes. Store vessels and a gas booster (ISCO pump) are used to inject various gases and water into the coal at low rates. In the experiments the maximum generated pore pressure is about 90 bar. After loading a coal sample with methane, the flushing CO_2 is put directly into the pump. After leaving the coal, the product fluid and gases are passing a drying container between a backpressure valve and the gas analyser. The gas analyser gives the composition of the product gas, the drying container the amount of produced water. In general an experiment takes 2 to 6 weeks, so an automatic registration of all environmental parameters is done with a data-acquisition system. Measured are the annular pressure as a substitute for the lithostatic pressure, the pore pressure in the sample and differential pore pressure over the sample, the gas/fluid injection and production rate, the gas composition, the weight and volume of injected gases and fluids, temperature of the coal sample and the fluids and the volume changes as a result of the annular pressure, pore pressure, fluid flow and temperature changes of the pressure vessel and the sample. The gathered data are used to calculate the capacity and flow characteristics of the coal.

Table F-1. An overview of the CO_2-flushing experiments of CH_4-saturated coals.

Experiment	**A**	**B**	**C**	**D**	**E**
Coal sample	K3	K3	K6B	K3	K5
Wet/Dry sample	Dry	Wet	Dry	Wet	Wet
Temperature (K)	310	310	295	295	310
Injection rate CO_2 (l/h)	$6 \cdot 10^{-3}$	$6 \cdot 10^{-3}$	$5 \cdot 10^{-4}$	$5 \cdot 10^{-4}$	$7 \cdot 10^{-4}$
Injection rate CO_2 (mole/h)	$10 \cdot 10^{-3}$	$10 \cdot 10^{-3}$	$8.5 \cdot 10^{-3}$	$8.5 \cdot 10^{-3}$	$12 \cdot 10^{-3}$
Injection pressure (MPa)	4	4	6	6	8
Annular pressure (MPa)	8	8	10	10	10
Inter granular pressure (MPa)	4	4	4	4	2
Injected methane (gram)	16.62	7.70	15.8	17.79	15.89
Injected water (gram)		94		58	83

Experimental procedure

Each experiment requires an elaborate initialisation phase. After mounting the sample in the high-pressure reactor and testing of the tubing system for leaks, the sample is attached to a vacuum pump for at least 24 hours up to 1 week, to remove the (adsorbed) gases and water. Thereafter the coal is filled with methane in cycles (Figure F-6). After each injection the methane is allowed to adsorb on the

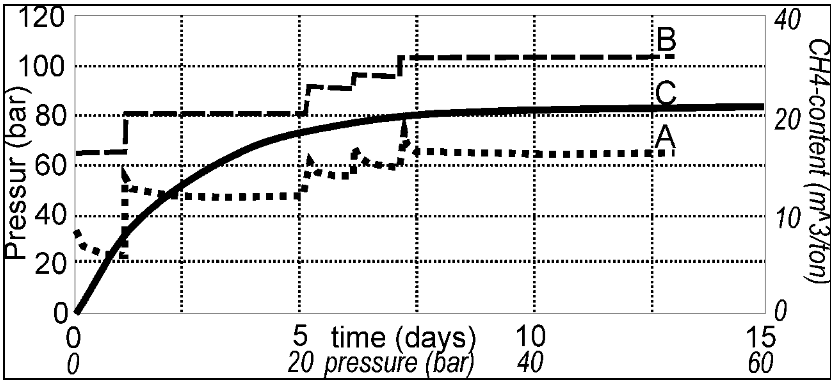


Figure F-6. Example of gas pressure build-up (left Y-axis, upper X-axis) in the sample (A) and the annular space (B). The method is used to calculate a Langmuir-curve (C) (right Y-axis, lower X-axis) to calculate the stress-permeability relation and to estimate bulk sorption behaviour.

coal matrix until equilibrium is reached. The procedure is repeated till the required pore pressure is reached. The mass of the injected methane is counted by a mass flow meter. Thereafter optionally water is injected and both, the tubing and the pump are brought to the same pressure and temperature conditions as the methane filled sample. More methane will adsorb and again time is needed for this methane to reach a new equilibrium pressure. To meet sub-surface conditions, the pressure difference between the annulus and the pore pressure is usually kept at ratios in between 2:1 up to 5:3. At the same time the sample and vessel are brought to the desired temperature. In the subsequent injection cycle the ISCO pump is filled and the pump and the tubing system is brought to the same pressure and temperature as the coal sample. As the CO_2 injection starts, the gas analyser determines the relative amount of methane, carbon dioxide and nitrogen (for annular leak detection) in the product gas. During the tests the recorded data serve as an iterative feedback in order to rule out their influence in the interpretation afterwards.

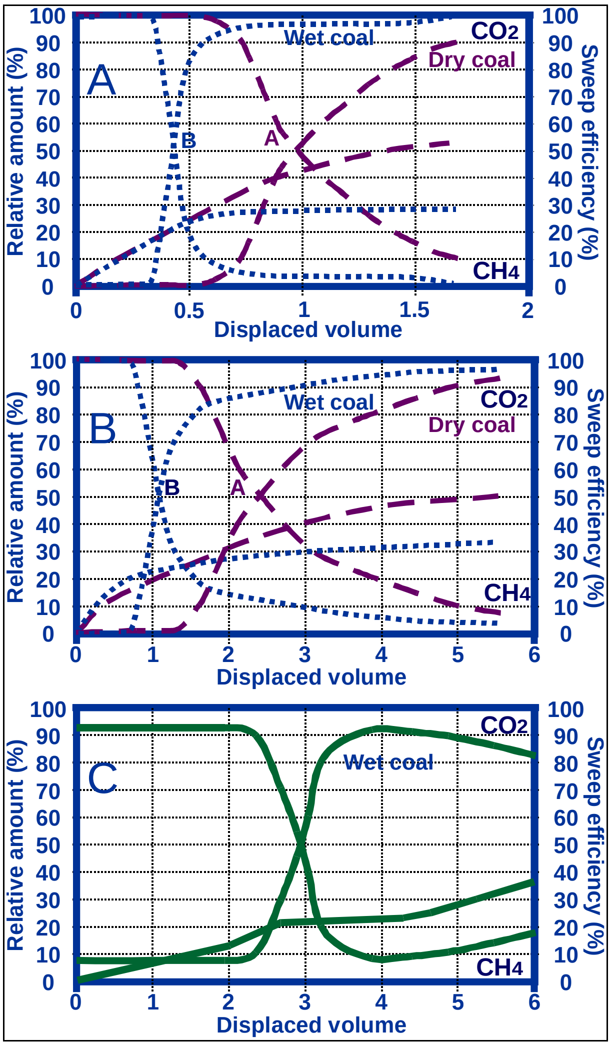


Figure F-7. **A**: Displaced volumes and sweep efficiencies of CH_4 and CO_2-gas in dry (A) and water saturated (B) coal. **B**: Displaced volumes and sweep efficiencies of CH_4 and liquid CO_2 in dry (A) and water saturated (B) coal. **C**: Displaced volumes and sweep efficiencies of CH_4 and super critical CO_2 in water saturated coal.

Experimental results

The filling experiments proved that the samples are able to hold methane, up to 22 m^3/tonne of coal. An extensive description of the most important experiments is given in the Novem Technical report by Bertheux et al. (2000). Here the combined results of seven flushing experiments are compared:

- a water free coal with a CO_2-gas and CO_2-liquid flushing (Figure F-7 A, B and Table F-2)
- a water saturated coal with methane replacement by CO_2-gas and CO_2-liquid (Figure F-7 A, B and Table F-2)
- a water saturated coal and methane replacement with supercritical CO_2 (Figure F-7 C and Table F-2)

The injection rate on all experiments is the same; $6 \cdot 10^{-3}$ mole/hr. The pore pressures of these experiments vary, since CO_2 is injected in three different phases, so the injection rates in l/hr differ considerably. The product gas and displaced volumes are normalised to atmospheric conditions.

Table F-2. Results at 90 % CO2.

	Methane sweep efficiency ratio (-)	**Displaced volume (mole/mole)**	**Running time (sec)**
A: Dry coal, CO_2 gas	52	1.65	$7.5 \cdot 10^5$
B: Water wet coal, CO_2 gas	26	0.55	$1.05 \cdot 10^5$
C: Dry coal, CO_2 liquid	48	4.9	$2.07 \cdot 10^6$
D: Water wet coal, CO_2 liquid	30	3.0	$8.6 \cdot 10^5$
E: Water wet coal, CO_2 super critical*	> 40*	3.82	$1.9 \cdot 10^6$

*After reaching a maximum of 92 vol.% of CO_2, the methane content slowly increased again after a DV of ~ 4

The comparison of the experiments performed on dry and wet (Sw = 1) coal samples shows that in wet coal samples the sweep efficiency is drastically smaller than the sweep efficiency in dry coal samples. Water obstructs the carbon dioxide in reaching the small methane saturated pores of the coal.

From the comparison of the dry and wet experiments at 4MPa with the dry and wet experiment at 6Mpa it is demonstrated that:

- An increase of the carbon dioxide injection pressure of 4 MPa to 6 MPa has no major influence on the sweep efficiency of the experiments.
- Supercritical CO_2 in wet coals originally behaves like liquid CO_2. Relatively fast break through. However, after a maximum CO_2-production, methane is slowly swept from the matrix and CH_4-production slowly recovers. This experiment shows the secondary replacing capacity of carbon dioxide for methane and water under supercritical conditions.

When the laboratory results are interpreted to seam/field scale, the following interpretations can be made:

- CH_4/CO_2-production patterns from dry coal with liquid phase CO_2 or gas phase CO_2 look very similar. The displacement volumes show that a transition (flush) zone from methane saturated to carbon dioxide saturated coal will be small.
- Consequently, on field scale especially dry coals swiftly exchange CH_4 for CO_2 and high sweep efficiency appears to be easily created when the water is pumped away (Figure F-7 A, B line A).
- In all water-wet systems, the major part of the water is rapidly removed. First there is a high water production from the cleat system, thereafter a very slow production from the matrix follows.
- In water saturated coals water seriously obstructs the CO_2 in reaching the matrix pores (Figure F-7 A, B line B). First the cleat system is swept clean of methane and water. Then, under wet conditions several times the original pore volume is needed to replace a part of the CH_4 for a part of the CO_2.
- Consequently, at field scale a transition zone from a CH_4-saturated to a CO_2-saturated coal will be large.
- The use of super critical CO_2 in wet coals shows satisfactory results. Despite a fast but very small breakthrough of CO_2, for a long time, methane is removed at high rates. After maximum CO_2 breakthrough again the production of methane is slowly recovering. It results in a higher sweep efficiency of methane and water and an improved CO_2-storage capacity.

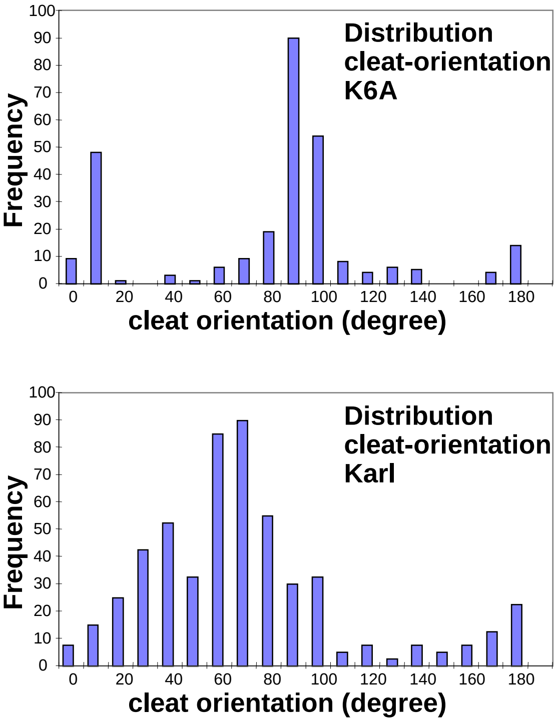


Figure F-9. Cleat orientations of two coal types.

Till now experiments are realised under ideal conditions, such as constant and slow CO_2-injection, dry or water saturated coals and no saline water. Various sources report a change in wettability of coal with higher pressure and phase change of CO_2. Some types of coal are reported to transfer from water wet, as was the case in this research, to CO_2 wet (Chi et al. 1987). This is very important for the diffusion of CO_2 into a water-wet matrix and consequently for the CO_2–water and CH_4 replacement process. This process will be an research issue.

Image analysis on cleat characterisation

In (E)CBM flow models the cleat systems of a coal usually are configured as an orthogonal system of equidistant fractures. However, in nature the cleat system consists of an irregular pattern of larger face/butt cleats and small “inter

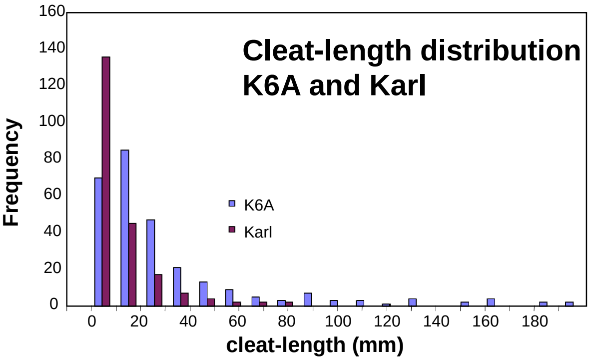


Figure F-8. Cleat length distribution of two coal types.

cleats". Both types of cleat systems have a series of face/butt cleat angles, varying from 90° to 30°, which depend on their tectonical and burial history. At the best a spreading with an average of cleats, cleat sizes and cleat orientation can be determined. These data series are to be used in cleat distribution models, and are needed for simulations. To get these distributions, two methods have been used to characterise the cleat systems.

Method 1

Measuring the spatial characteristics of cleats in a coal slab parallel to the layering. The main cleats are filled with a fluorescing dye and characterised by image analysis with blue-violet light. The QWin application for the Quantimet image analysis system was used to qualify the cleat angles (Figure F-9) and to quantify cleat lengths (Figure F-8) of the coal samples K6A and Karl. The cleat size and cleat orientation are determined by measuring the main fractures in a coal slab perpendicular to the layering. These major fractures are filled with a fluorescing dye and characterised by image analysis using blue-violet light. The gathered data are imported into spreadsheets for further sorting and grouping as shown. The cleat area is calculated on the basis of the QWin result. This cleat area parameter is used to determine the maximum compaction of the cleats.

The data show that the Karl coal type consists of many small cleats whereas the K6A coal contains a much favourable spreading of small and large cleats. As a result, in the K6A sample the appearance of face and butt cleats were very distinct. A high spreading of the cleat length is not desirable. When many small fractures are present, the flow direction changes constantly, which leads to a higher tortuosity and consequently a lower permeability.

Method 2

Measuring the spatial characteristics of coal fines from crushed samples or cuttings provide information of large amounts of, to some extent, representative grains. Image analysis data produce among others statistical maxima of cleat distances and cleat angles, assuming that the coal is cracked according to its cleat structure. After processing the grain images the gathered numerical information consists of general data, such as; area, length breadth, perimeter, and rotation data, such as; the rotation angle and cleat length (Figure F-10). These data are regrouped on lengths, orientations, etc. and sorted on sphericity and roundness. In order to separate angular grains from the entire data set, various geometrical filters, which are characteristic for oblique shapes, are applied. Conclusively the results show that a major part of all the particles resemble the geometrical filters of parallelograms of 90° and to a lesser amount of 70° and 80°. However, sample K6A has a dominant cleat angle of 80° to 90° for the face a butt cleats and about 90° perpendicular to the bedding plane. For the Karl-samples a 60° to 70° angle for the face and butt cleats and also about 90° perpendicular to the bedding plane are recognised.

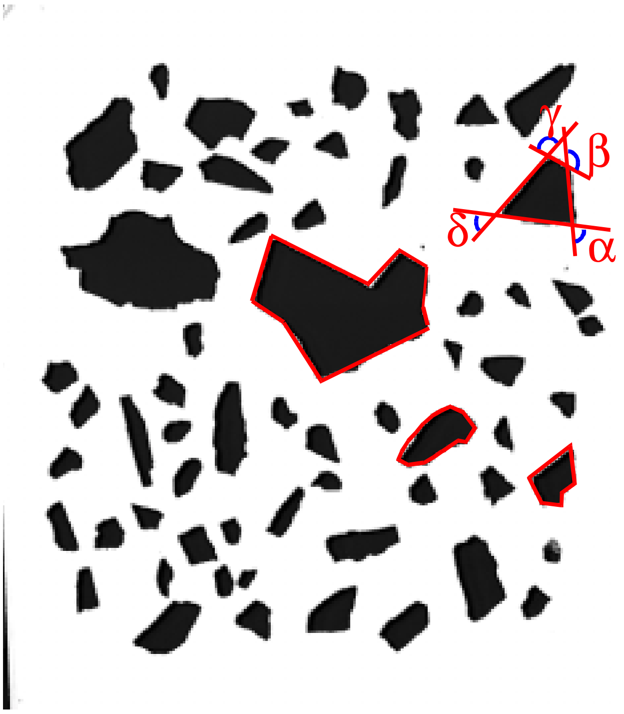


Figure F-10. Coal particles or drilling cuttings as used for cleat and cleat angle definition.

Conclusively can be said that:

- The wide range of orientations, as recognised in the Karl sample, reflects its complex geological history, which results in trapezium shaped matrix blocks.
- The many orientations present are assumed to show high tortuosity values, which have a negative effect on the conductivity characteristics.
- For the K6A sample the two main orientation indicate that the face and butt cleats are almost perpendicular. This has a positive impact on the flow characteristics because of the low tortuosity.

However, the coal is better compacted, which results in a stronger aperture decrease of the cleats. So the Karl sample is better resistant to cleat closure as a result of the shape of the matrix blocks, since a smaller cleat closure leads to a higher permeability.

- Another positive effect of the Karl sample is the large amount of cleats per surface of coal giving high cleat porosity and therefore a positive effect on the diffusivity through the matrix.

Conclusion

The image analysis methodologies on slabs and cuttings show that the use of image analysis improves the value of quantitative information. Data can be used for the development of cleat/matrix models, using a spatial distribution of cleat distance and orientations. The slabs give a good impression on the general cleat-orientation. However, the spatial accuracy is rather low. This problem is solved when cuttings are used. Nevertheless, an improvement of geometrical filters is needed, to optimise the data-accuracy. With respect to "cleat-width" distribution, to be used in fluid models, just a little work is done. Here all the detailed work is to be done in a coming programme.

Translation of experimental results to micro-modelling work

The laboratory results, as previously described, are applied in reservoir calculations. Conventional reservoir simulators are not suitable for reproducing the performed experiments because they are not dealing with differential sorption behaviours of multi-phase CO_2, CH_4 and water. The sorption/diffusion behaviour, related to the cleat Darcy flow, is the special feature of the CO_2-ECBM technique. In-situ coal parameters, in relation to reservoir characteristics, fysio-chemical factors and cleat-spatial dimensions, are used at a matrix-cleat scale, to make both laboratory results and field tests reproducible. One likes to know the interactive behaviour between the matrix and cleats. Further one likes to know the effect of the cleat dimension and water saturation on the diffusion and sorption behaviour of CO_2 and CH_4 in the macerals of the coal matrix (Figure F-11).

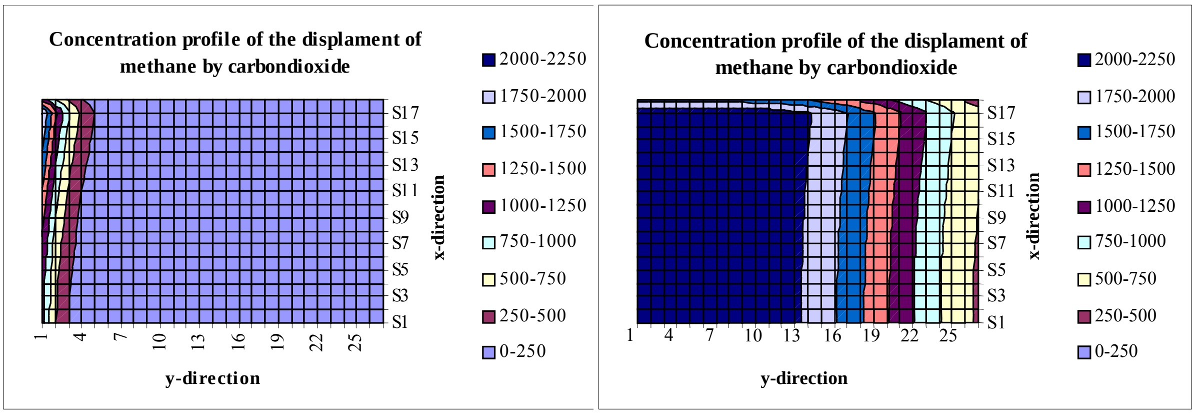


Figure F-11. Modelling results on sweep efficiency of coal; one cleat and matrix.Left: Elapsed time: 1.07 hour; recovery: 3.80 %; CH4 produced: 0.24 mole; CO2 stored: 0.32 mole; ddx 0.0001 m; phi 0.03; v-inj: 0.0005 m/s. Right: Elapsed time: 16.54 hour; recovery: 75.97 %; CH4 produced: 4.08 mole; CO2 stored: 4.75 mole; ddx 0.0001 m; phi 0.07; v-inj: 0.0005 m/s.

This information is used for the input parameters of a multi-cleat/matrix system or seam scale modelling. Micro-models are constructed by (de Haan 1999) for dry coals, methane and gas phase carbon dioxide. For water saturated coals, methane and liquid/super critical carbon dioxide. Bertheux et al. (2000) developed a model. The results for the simulations on dry coals and gas phase CO_2 are:

From the simulations the following conclusions can be made:

- If the diffusion/sorption related parameters are kept constant, a coal with a low matrix porosity has a higher storage capacity for carbon dioxide than coal with a higher porosity.
- To keep methane concentrations and sweep efficiencies high, low CO_2 injection rates are essential.
- The final recovery is not influenced by pore pressure, temperature or other studied parameters. It mainly depends on flush-time.
- Small cleat apertures configurations give the best approximations for plug flow simulations.

The results for the simulations on wet coals and liquid phase CO_2 are:

- During the simulation a much higher efficiency is reached than in the experiment (Figure F-12). During the experiment, with a pore pressure of 4 MPa, only free methane gas from the cleats is produced.
- Here in contrary with the dry coal situation, the cleat opening and injection velocity only have a relatively small effect on the sweep efficiency and cannot explain the discrepancy between the experiment and simulation.

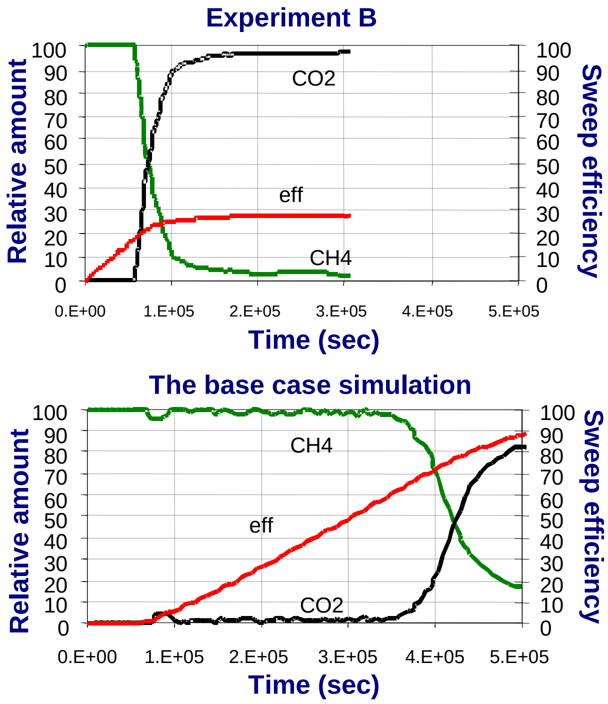


Figure F-12. Comparison of the sweep efficiencies and CH_4/CO_2-exchange in experiment B (top) and the base case simulation (bottom).

Conclusion

The micro-simulations are proving to be valuable. The simulations of the “dry cases” are in accordance with the experiments. The simulations on the water saturated coals are showing some discrepancies. A combination of the following reasons may add to the divergence between the results of the simulations and experiments:

- The adsorption isotherms that are used in the simulations were measured on dry coal samples. Adsorption isotherms can be different for wet coal samples.
- The tortuosity is not taken into account in the simulator. Indeed, the effective diffusion constant is inversely proportional to the tortuosity factor τ.
- In the experiment the cleats are filled with water. A distribution of cleat openings may lead to a situation in which the smaller cleats remain filled with water and hence only the part of the matrix adjacent to cleats with large cleat openings is effectively accessible.
- Equilibrium between the free gas and the gas dissolved in water at the cleat/matrix boundary is not immediately established.

These themes, together with subjects such as; water saturation, salinity, pore/cleat pressure differences, overburden integrity for gases, etc., are subject for further study.

Annex G Translation of experimental results to reservoir field simulations

K-H. Wolf, O.H.M. Barzandji and H. Bruining (TUD)

Simulation is used to determine optimum well spacing in a basin. It also gives guidance on placing wells and improving field economics. At pressures greater than the desorption pressure, no desorption occurs. Under this pressure, the Langmuir formula relates adsorbed gas concentration in a coal matrix, and the free gas pressure in a cleat and this was used in the field scale simulations. The adsorption of gas on the surface of the coal can be modelled as gas dissolved in immobile oil (Seidle and Arri 1990). To perform enhanced recovery of CH_4 by injection of CO_2 it is possible to use STARS, which is a three-dimensional multi- phase reservoir simulator that incorporates multi-component gas. STARS, has the capability to input K values as a function of total pressure and the concentration of one component, so it can represent binary gas sorption on coal. It is however necessary to adjust the input parameters to the simulator such as porosity relative permeability and saturation. The solution gas oil ratio of this immobile "pseudo" oil is calculated from Langmuir adsorption isotherm constants and coal bed properties. The laboratory tests provide us with representative permeability and porosity values. Under-saturated coal beds may have much lower desorption pressure than the reservoir pressure, as is the case with west-European coal beds. Because of this, the values for V_m (Langmuir gas constant) are taken lower than the values found by the experiments. Initial pressures, well radius, and seam thickness were obtained from the Belgian-Dutch coal bed methane test; KS-206 Peer. We used the following criteria in conducting the simulations; total coal seam thickness of 7.62 m (25 ft.), porosity of 2 %, permeability of 1 mD, and a total gas content of 10 m^3/metric ton (320 scf/ton). For the gas water relative permeability, those reported by (Sawyer et al. 1987) were used for our problem. Regarding enhanced recovery, production is initiated from the peripheral wells, by the time these wells undergo primary recovery beyond the peak CH_4 production rate, then the injection well is drilled in the centre of the drainage area, and CO_2 is injected.

Depending on the drainage area, there is an optimal horizontal length of inseam drilling, beyond which the additional drilling and maintenance costs do not offset additional revenues. The simulation results coupled with economic calculations reveal the optimum length of horizontal wells in view of the drainage area of the coal. Our laboratory experimental results provide us with the input data regarding reservoir parameters that is used in our reservoir simulator. Simulation of methane production, both primary and CO_2 enhanced are carried out. Optimisation of the injection and production schemes, and the well spacing for the selected pilot sites are carried out.

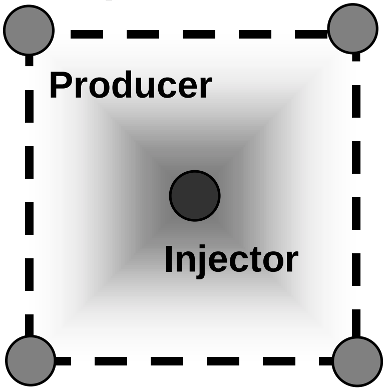


Figure G-1. Basic field lay-out for modelling CO_2 injection in a coal methane reservoir.

Drilling and completion of CO_2-Enhanced CBM wells

For the NW European situation, and especially the Netherlands, the most important aspects of drilling and completion have been considered in relation to known geological and reservoir technical aspects. To get a visual perception on the aspects of CH_4 production and CO_2 injection, Figure G-1 shows a schematic outline of the paired production and injection wells. Figure G-2 shows the wells with their related surface facilities Drilling and completing an open hole or a cased hole in coal zones, is a question of cost versus return (Clark and Hemler 1998). Open hole completion assumes a larger hole with a gravel pack or a slotted liner. This entails less controlled stimulation, production of coal fines, and is defined as no cement on formation. This type produces best, with 7 inch casing set above the coal zones. It works best with a single coal zone or a closely grouped coal zones. If several coal zones extend over 30-100 meters, a liner should be used. Cased holes assume a smaller hole, perforations, controlled stimulation, minimal coal fines production, and moderate clean out and repair work-over. In cased hole completion, the 7 inch casing is set above the coal zones, then a 5½ inch casing is set through the coal and perforated. Perforating the casing should allow both maximum stimulation and cleanup, as well as maximum production. Injection well completion is also carried out by perforating the 5½ inch cemented casing across the coal zone, then the injection packer is set and the tubing is installed. Surface Facilities; Coal gas wells are usually troublesome for production equipment because of coal fines produced with methane and water. Due to the high gas to liquid ratio, vertical separators work best, and handle large capacity. The produced gas from the separator should go through a cartridge type filter to prevent downstream problems in the dehydrator, compressor and flow meter. Filtration of the produced water is usually required to prevent damage to a disposal well. Dehydration of CBM is based on conventional glycol systems developed for gas wells. Glycol adsorption of water vapour works best at low temperature and high operating pressure. Most CBM wells are not capable of continuous fluid flow so they need artificial lift like, sucker rod pump, which is placed in the tubing at or below the producing formation. It has proven to be cost effective, through minimising plunger wear and maximising sustained pumping. Cavity type pumps are highly tolerant of solids and are cheaper, but high gas rates cause excessive pump wears. The produced gas is re-circulated to keep the well flowing, it doesn't involve a packer and gas lift valves. Coal gas wells initially produce high volumes of water (1.5 to 15 m^3/d). The produced water volumes are decreasing with time. Coal water contains predominantly sodium bicarbonate, which form scales. These waters can be injected in disposal wells, which are preferred to surface pits. Their capability exceeds produced water volumes, but their quality must meet Environmental Protection criteria, including compatibility with formation waters.

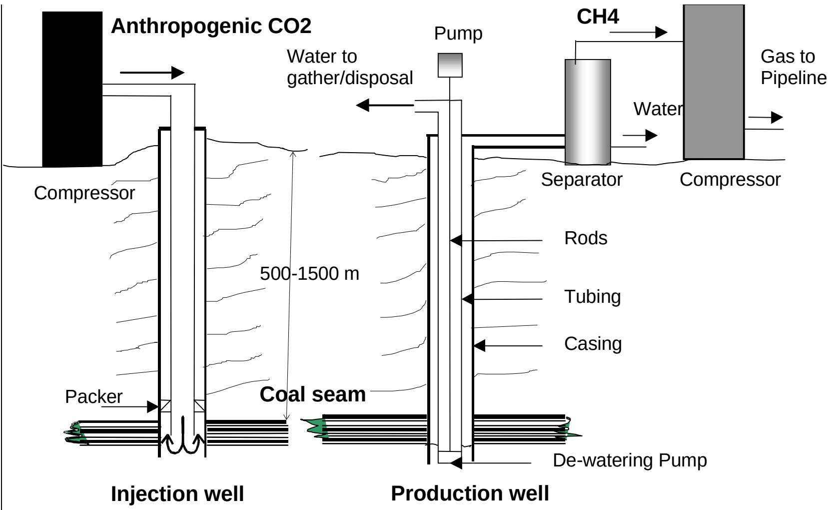


Figure G-2. Well configuration and surface facilities for CO2 injection and water/methane production.

Inseam wells

The effect of inseam drilling can be looked at as a very effective way of stimulating the coal seam, or reducing the effective drainage area. As the length of a horizontal well is increased, its contact with the reservoir increases. Therefore as the horizontal well length increases, net revenues also increase to a certain extent. At some point the additional drilling and maintenance costs do not offset additional revenues. Consequently, the simulation results coupled with economic calculations reveal the optimum length of horizontal wells in view of the drainage area of the coal. Hence, the simulation is carried out for a vertical hole with (-3) skin, then for various ranges of horizontally drilled inseam holes. Various scenarios of different well spacing are used, and also different durations of field development.

Example of a preferred simulation of a 1 km^2 area.

Here we show one of the prefered cases of 100 hectare, or a 1000 by 1000 m drainage area.
The following adaptions were performed on the simulation of this case:

- A permeability of 2 mD was used, here we assumed a lithostatic pressure minus pore-pressure of 20 bar or less.
- Both the injection and production wells were accommodated with inseam drilling and a skin factor of (–3).

With these provisions it is possible to commence CO_2 injection right from the beginning. In this case the time to reach peak gas production rate has reduced from 28 to 10 years, with about 90 m inseam drilling, the corresponding peak gas production rate has increased from 2550 to 5300 m^3/day. The cumulative CH_4 production has increased from 8 to 30 million m^3 in 20 years. In this case the effect of longer inseam drilling is most pronounced, as it is clearly indicated in Figure G-3.

With CO_2 injection right from the beginning, the peak methane production rate can increase from 5300 to 9000 m^3/day. CO_2 injection rate is about 7080 m^3/d. The injection pressure is rather high for shallow wells about 125 bars at the beginning of the injection process, but gradually comes down as more water is produced and gives way to methane production. Figure G-4 shows as the results of simulations. An improvement in methane production with CO_2 injection from 30 to 38 millions m^3 in 20 years with no CO_2 breakthrough is calculated and a total of 51.7 million m^3 (95600 tons) CO_2 is sequestered in 20 years. Figure G-5 represents the contrast in concentration of carbon dioxide versus methane or the sweep efficiency of CO_2 at different periods of injection and production times. The elongated area swept by CO_2 is due to the inseam drilling assumed for the injection well. The four patterns represent 1000, 3000, 6000, and 10000 days after the start of injection and production scheme.

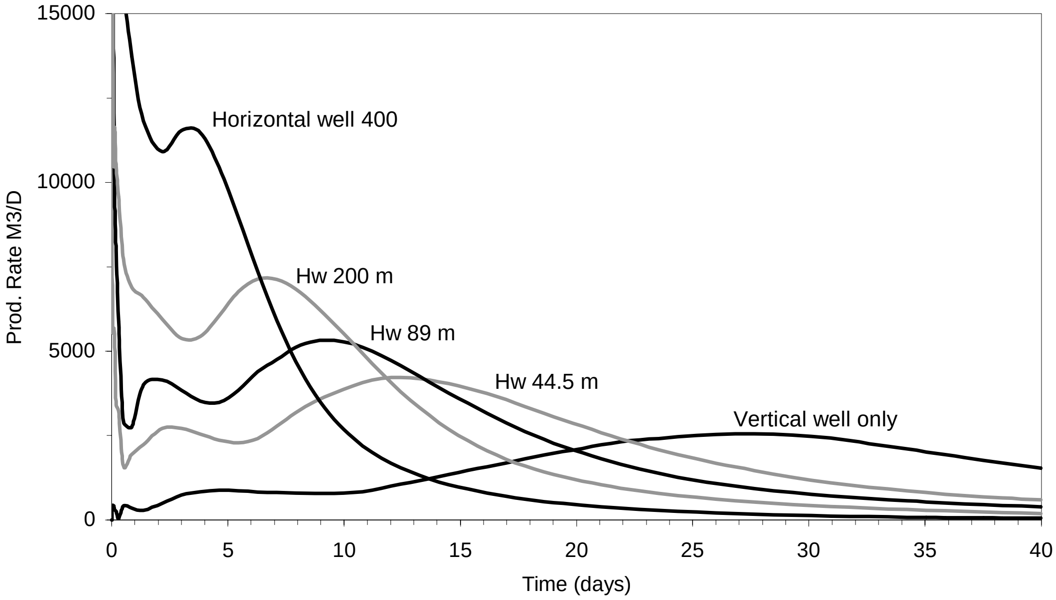


Figure G-3. Example of the effects of inseam drilling on methane production rate of a 1000 m spacing configuration.

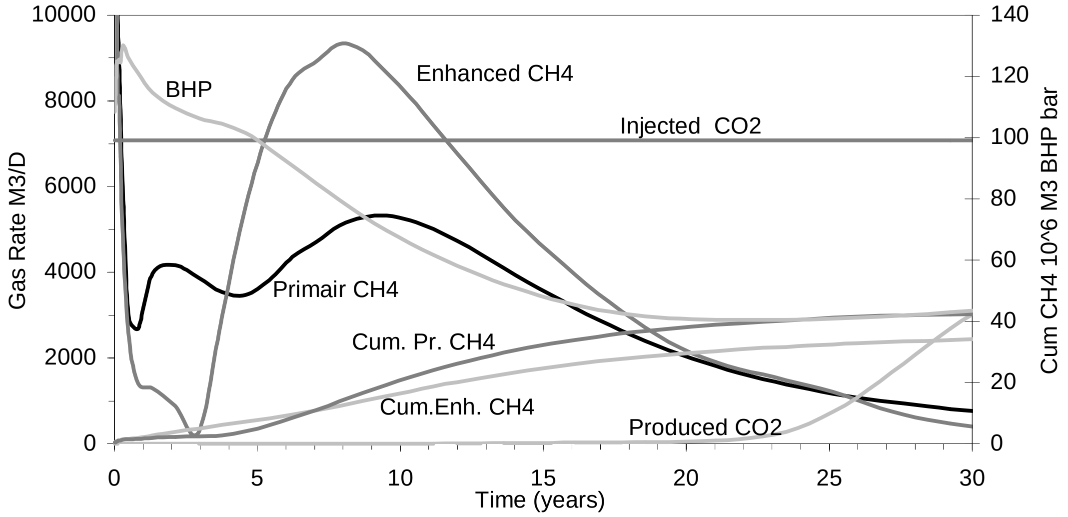


Figure G-4. Examples of methane rate, and cumulative production, CO_2 injection, production rate, and pressure of a 1000 m spacing case.

One point emerges for certain from these preliminary studies, and that is through inseam drilling larger drainage areas can be exploited with higher rates, and easier CO_2 sequestration, subsequently more economically sound results.

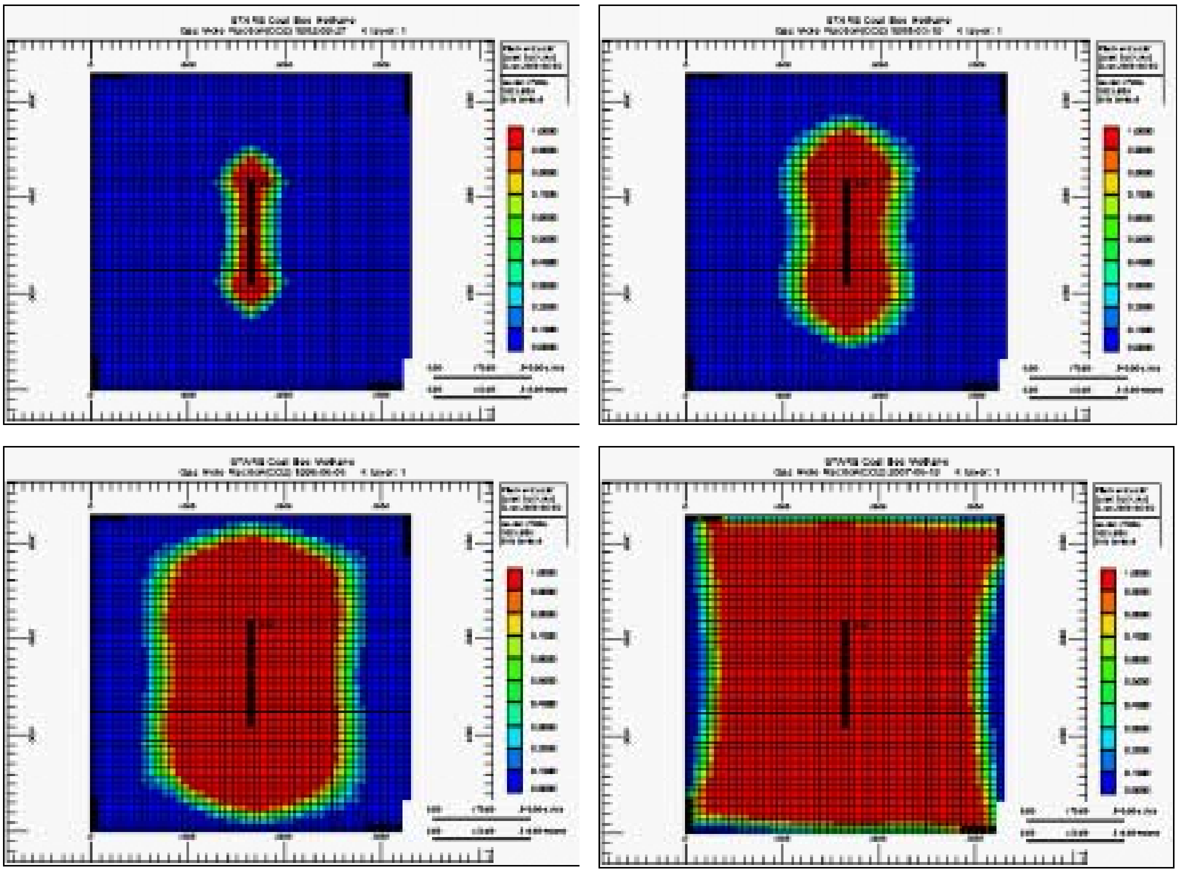


Figure G-5. Carbon dioxide concentration (swept area) with time in contrast with methane concentration at 3, 8, 16 and 27 years.

Alternative drainage areas and well spacings

A good example for a methane drainage area is White Oak Creek Field in Alabama. It has an area of 10 by 15 km., with about 300 wells. This averages to 2 wells per square kilometre. In most parts of the field there are 4 wells per square kilometre. On average, 55 wells were drilled per year in the period 1995 to 1999. If we take the case of de Achterhoek in the Netherlands in which, based on geological information, blocks of about 4 by 4 km can be planned, we are able to get concentration of 32 to 64 wells per block. However, we expect lower drilling rates in the Netherlands, due to:

- the densely populated region,
- moderate availability of drilling and operation contractors, and,
- the influence of public way of thinking.

Based on the reservoir simulation and economic evaluation, the following four options are considered for blocks of 4x4km:

Case 1: A well spacing 400 m.
Case 2: A well spacing 600 m.
Case 3: A well spacing 800 m.
Case 4: A well spacing 1000 m.

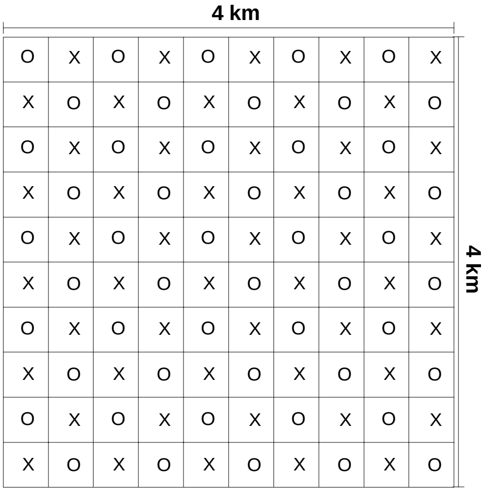
Case 1.

A drainage area of 16 hectare, well spacing 400 m (1/0.162 = 6 wells per square km), 10x10 blocks. This results into (Figure G-6 and Figure G-7):

- 50 Injector wells marked x
- 50 Producer wells marked o
- Total number of wells is 100
- Profitable with stimulation and reasonably short production terms (15 to 20 years).
- Drilling at a rate of 10 wells per year will require 10 years to complete drilling the 100 wells.
- This case involves only vertical wells and no inseam drilling.

Remark:

- High sweep efficiencies.
- Relatively expensive due to the high well density. However the use of uncomplicated direct wells will reduce the costs considerably.



o	x	o	x	o	x	o	x	o	x
x	o	x	o	x	o	x	o	x	o
o	x	o	x	o	x	o	x	o	x
x	o	x	o	x	o	x	o	x	o
o	x	o	x	o	x	o	x	o	x
x	o	x	o	x	o	x	o	x	o
o	x	o	x	o	x	o	x	o	x
x	o	x	o	x	o	x	o	x	o
o	x	o	x	o	x	o	x	o	x
x	o	x	o	x	o	x	o	x	o

Figure G-6. Case 1, 10x10 blocks of production and injection wells.

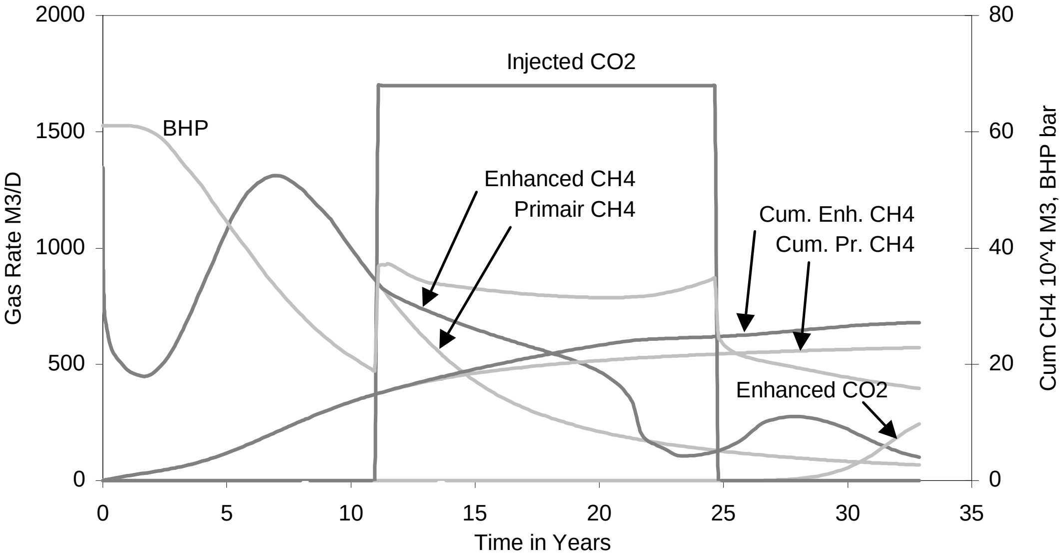


Figure G-7. Production rates and cumulative productions for CH_4 and CO_2 for case 1: Spacing 400 m, skin –3.

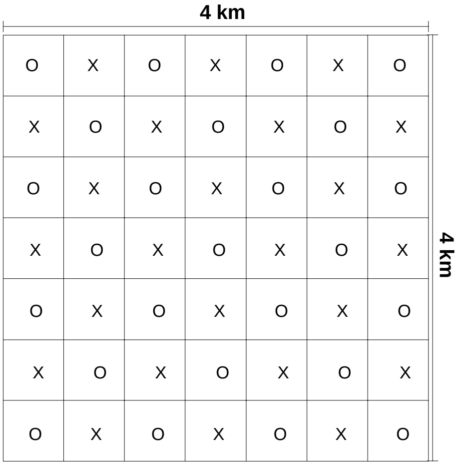
Case 2

A drainage area of 36 hectare, well spacing 600 m (1/0.324 = 3 wells per square km), 7x7 blocks. This results into (Figure G-8 and Figure G-9):

- 24 Injector wells marked x
- 25 Producer wells marked o
- Total number of wells is 49

Remark:

- Profitable with inseam drilling (>25 m) and reasonably long production terms of about 20 years.
- This concentration of wells resembles the case of White Oak Creek in Alabama. As we have lower permeability coals in the Netherlands it is essential to have inseam drilling, to compensate for this deficiency.
- Drilling at a rate of 10 wells per year will require 5 years to complete drilling the 49 wells.



O	X	O	X	O	X	O
X	O	X	O	X	O	X
O	X	O	X	O	X	O
X	O	X	O	X	O	X
O	X	O	X	O	X	O
X	O	X	O	X	O	X
O	X	O	X	O	X	O

Figure G-8. Case 2, 7x7 blocks of production and injection wells.

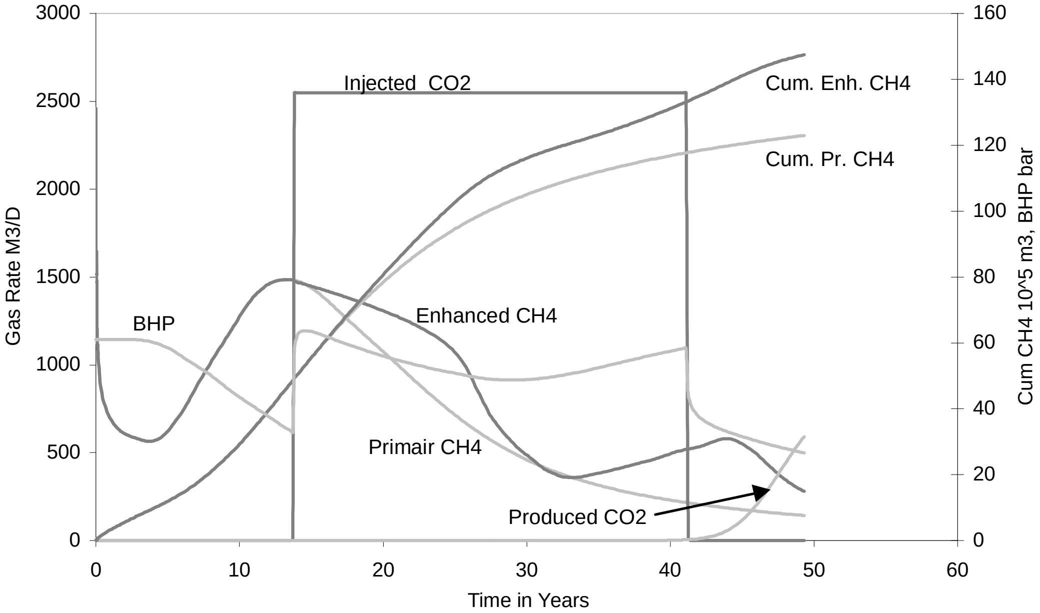


Figure G-9. Production rates and cumulative productions for CH_4 and CO_2 for case 2: Spacing 600 m, 27 m inseam drilling.

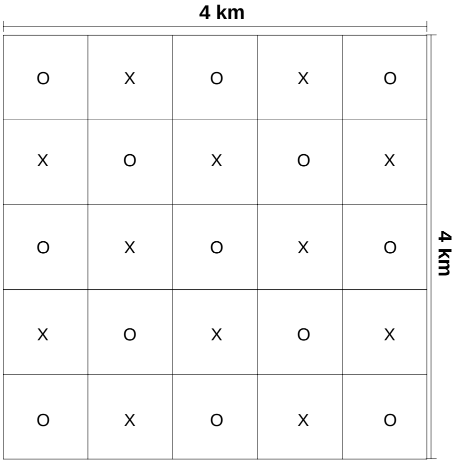
Case 3

A drainage area of 64 hectare, well spacing 800 m (1/0.648 = 1.5 wells per square km), 5x5 blocks. This results into (Figure G-10 and Figure G-11):

- 12 Injector wells marked x
- 13 Producer wells marked o
- Total number of wells is 25

Remark:

- This option will be profitable with long inseam drilling (>200 m) and long production terms (> 20 years).
- All the wells can be used as producers at the beginning. Thereafter each row of the wells, starting at one side, can be converted to injector wells after the reservoir pressure has reasonably declined (normally to a quarter of the initial reservoir pressure). This is usually after a production period of about 10 years, depending on the extent of the inseam drilling, well radius, stimulation and permeability of the coal seams.
- Drilling at a rate of 10 wells per year will require 2.5 years to complete drilling the 25 wells.
- Inseam drilling is favoured when there are thick beds of coal, or closely grouped coal zones, that are easily connected to each other.



o	x	o	x	o
x	o	x	o	x
o	x	o	x	o
x	o	x	o	x
o	x	o	x	o

Figure G-10. Case 3, 5x5 blocks of production and injection wells.

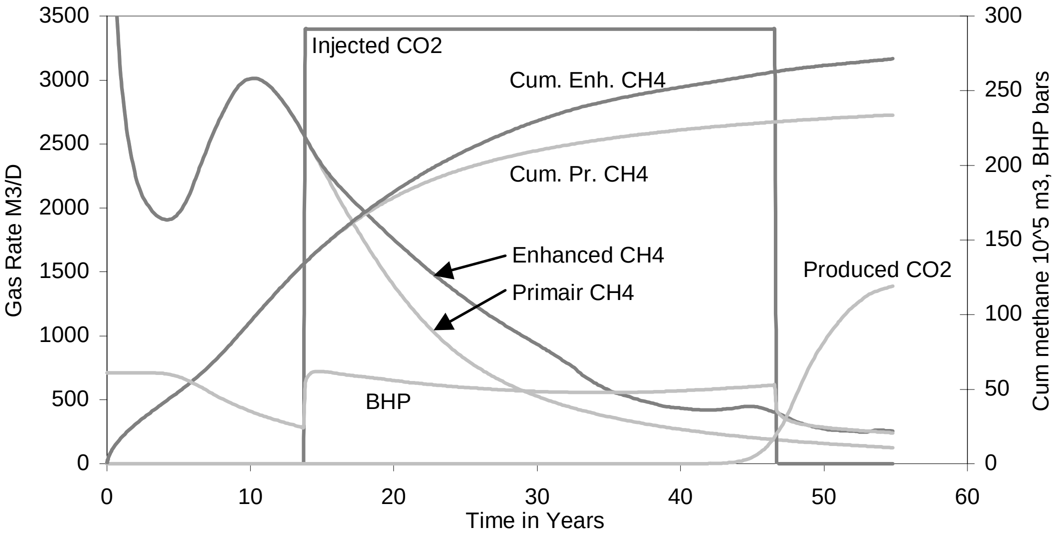


Figure G-11. Production rates and cumulative productions for CH_4 and CO_2 for case 3: Spacing 800 m, 249 m inseam drilling.

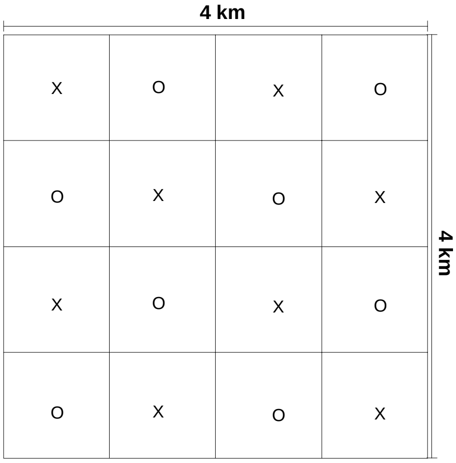
Case 4

A drainage area of 100 hectare, well spacing 1000 m (1/1.0 = 1.0 wells per square km), 4x4 blocks; This results into (Figure G-12 and Figure G-13):

- 8 Injector wells marked x
- 8 Producer wells marked o
- Total number of wells is 16

Remarks:

- Profitable with long inseam drilling (>400 m) and long production terms (> 50 years).
- All the wells can be used as producers at the beginning, then each row of the wells from one side can be converted to injector well after the reservoir pressure has reasonably declined (to a quarter of the initial reservoir pressure). This is usually after a production period of about 15 years depending on the extent of the inseam drilling, well radius, stimulation and permeability of the coal seams.



x	o	x	o
o	x	o	x
x	o	x	o
o	x	o	x

Figure G-12. Case 4, 4x4 blocks of production and injection wells.

- Drilling at a rate of 10 wells per year will require 1.6 years to complete drilling the 16 wells.
- Inseam drilling is favoured when there are thick beds of coal, or closely grouped coal zones, that are easily connected to each other.
- We used the following criteria in conducting the simulations:
  Total coal seam thickness of 7.62 m (25 ft.), porosity of 2 %, permeability of 1 mD, and a total gas content of 10 m^3/metric ton (320 scf/ton). For the gas water relative permeability, those reported by (Sawyer et al. 1987) were used for our problem. Regarding enhanced recovery, production is initiated from the peripheral wells, by the time these wells undergo primary recovery beyond the peak CH_4 production rate, then the injection well is drilled in the centre of the drainage area, and CO_2 is injected.

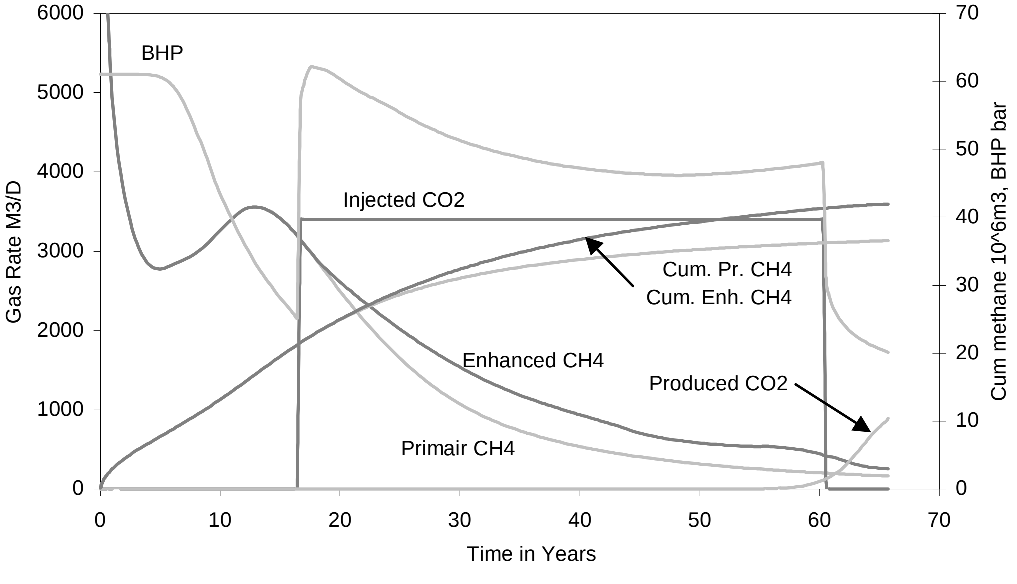


Figure G-13. Production rates and cumulative productions for CH_4 and CO_2 for case 4: Spacing 1000 m, 444 m inseam drilling.

Conclusive remarks

- When utilising K values for representing solution gas, STARS, can be used to simulate both primary and enhanced CBM.
- The time required to reach peak CH_4 production rate, and the total time needed to produce its CH_4 content depend to a large extent on well spacing.
- Optimum well spacing depends on coal seam permeability. The higher the permeability the larger the area which can be drained for the same period of time.
- The recommended well spacing for European coals should be around 40 acres for vertical wells depending on the permeability of the coal. Again, higher permeability permits larger drainage areas.
- Stimulation plays a significant role in improving both methane production as well as facilitating injection operations. Enhanced methane production allows more methane to be produced, at a shorter time, as well as facilitating the storage of CO_2, which in turn will help in reducing pollutant in the air and keep a cleaner environment.
- Regarding inseam drilling with the use of an eco-tax; longer (expensive) inseam drillings means larger drainage areas, higher production rates and consequently lower methane sales prices.
- The optimum length of the horizontal well is about 90 m for a drainage area of 100 hectare. It can also be concluded that smaller drainage areas favour shorter development periods, while larger drainage areas favour longer development periods.
- Concerning the Huff Puff method, it is inefficient and uneconomical in terms of saving energy, and displacing the methane by carbon dioxide.
- The laboratory experiments proved that at high pore-pressures the cleat-permeability dramatically increases and the sweep efficiency of the CO_2-pressure front will be high at depths above ~750 m.
- The effect of over-pressures on overlying roof rock is not investigated and should be considered in a follow-up study.

Annex H Some aspects of reservoir choice and well configuration for ECBM-purposes

K-H. Wolf (TUD)

Introduction

To evaluate reservoir properties for prediction of well deliverability, available well and geologic data is reviewed to select well locations. These data include structure and stratigraphic maps, drilling records, logs, and fracture studies, as well as gas content and permeability data.

Pilot testing is the best way to evaluate the productive potential of ECBM reservoirs. A properly designed testing program (injection/fall off tests and multi rate production test) can minimise the expense and predict long term productivity and ultimate recovery from ECBM wells. Due to the unfavourable geological situations the profits from the relatively difficult ECBM tight gas reservoir are low. However technically many improvements are already under development to produce coal gas from depths up to about 1500m.

CO_2 sequestered from power plants can be used to enhance coalbed methane and water production. A pilot program of CO_2 assisted coal bed methane production in the San Juan Basin, New Mexico, has been under way since 1996. The Allison Unit Pilot run by Burlington Resources is injecting 4 million cubic feet per day (113,000 m^3/D) of pipeline fed CO_2 from a natural source into a system of nine injection wells located in the San Juan Basin. Preliminary results indicate that full field development of this process could boost recovery of in-place methane by about 75%.
The criteria for achieving a successful application of this concept are:

- Presence of a favourable geology such as thick, gas saturated coal seams, buried at suitable depths and located in simple structural settings, which have sufficient permeability.
- Availability of low cost potential supplies of CO_2, either from naturally occurring reservoirs or from anthropogenic sources such as power plant flue gas.
- Gas demand, which includes an efficient market for utilisation of methane, including adequate pipeline infrastructure, long term end users, and favourable well head gas prices.

Some aspects of drilling and completion of ECBM wells in the Netherlands

For the NW European situation, and especially the Netherlands, the most important aspects of drilling and completion have been considered in relation to known geological and reservoir technical aspects. Completion and operation of coal gas wells begins with a decision on the choice of drilling and completing with open hole and a cased hole of coal zones. This is a matter of cost versus return.

Open hole completion

Open hole completion assumes a larger hole with gravel pack or liner, and less controlled stimulation, production of coal fines, and perhaps a high incidence of clean-out and other work-over. Open hole completion is defined as no cement on formation. This type produces best, with 7 inch casing set above the coal zones. Barefoot (no casing through the open hole section), works best with a single coal zone or closely grouped coal zones. If several coal zones extend over 30-100 meters, then some type of liner should be used.

Cased hole completion

For cased holes several specifications and requirements are essential:

- smaller hole are prepared,
- perforations in the production zones are essential,
- controlled stimulation often is needed, especially in very low permeable zones,
- minimal coal fines production, to prevent clogging, and,
- moderate clean out and repair work-overs are sometimes wanted.

In a cased hole completion the 7 inch casing is set through the coal zones or top set, and 5½ inch casing set through and perforated. For low water volumes and low fines production, a smaller casing (4 and 4 ½ inch) is both operationally and economically more effective. Using a larger casing allows more strength in stimulation or Frac design. Perforating the casing should allow maximum stimulation and cleanup, and maximum production.

Slotted liner and gravel pack completion

Slotted liner and gravel pack completion needs back flushing to remove plugging by coal fines. Resin coated sand may be used to seal the area around the well bore preventing flow back and preserving permeability.

Drilling fluids

Drilling fluids are selected to control formation pressure and minimise formation damage during drilling and completion operations. Coal zones usually flow coal fines when subjected to a low hydrostatic pressure. Drilling the coal with natural gas or air can wash out the coal and form a cavern. While high hydrostatic pressure (heavy mud) limits the flow of coal fines and minimise formation damage. However, heavy fluids are expensive and somewhat difficult to work with because of their corrosive nature. Typical mud programs for cased hole wells consist of either a gel- or starch-based mud, or a low solids non-dispersed system.

Cementation and perforation

The completion method employed in the Black Warrior basin is to drill the well through all coals using air. Thereafter a casing is cemented by using lightweight cement. Once the casing has been set, perforations are placed in the lower portion of the coal seam interval. The perforations are in siltstones or shales near the coal seams, rather than in the coal seams to minimise rubbleization of coals near the wellbore and to minimise the chance of obtaining multiple vertical fractures at the wellbore.

Surface Facilities

Coal gas wells are usually troublesome for production equipment to produce because of coal fines produced with methane and water. Design considerations and field operation quality of wellheads, separators, filters and dehydrators are also important.

- Wellheads with 2000psi rating are acceptable.
- Flow lines typically of 2 inch (3 inch for high volume wells) are adequate.
- Full operating ball valves for flow control are less likely to plug or cut out.
- Separators: most coal gas wells produce gas, water and coal fines, requiring two phase separators. Because the gas to liquid ratio is usually high, vertical separators work best, and handle large capacity. During production a well makes some condensate and a two-stage separator is recommended. A high pressure separates gas from the liquid and then a low-pressure vessel separates oil or condensates from the water.
- Filtration: produced gas from the separator should go through a cartridge type filter to prevent downstream problems in the dehydrator, compressor and flow meter. Filtration of the produced water is usually required to prevent damage to a disposal well.
- Dehydrators: dehydration of ECBM is the same as used for conventional glycol based systems developed for gas wells, by differing the maximum operating pressure, inlet gas temperature and CO_2 content. Glycol adsorption of water vapour works best at low temperature and high operating pressure. If the CO_2 content of the gas is more than 10% then use of stainless steel elements in the dehydrator should be considered.

Production aspects

Most ECBM wells are not capable of continuous fluid flow so they need artificial lift such as sucker rod pumps, cavity type pumps or gas lift systems. Figure G-2 shows a schematic outline of both production and injection wells with their related surface facilities.

- Sucker rod pump: a plunger pump with tolerance for solids, placed in the tubing at or below the producing formation. It has proven to be cost effective, through minimising plunger wear and maximising sustained pumping.
- Cavity type pump: these are highly tolerant of solids and are cheaper, but high gas rates cause excessive pump wears.
- Gas lift: produced gas is re-circulated to keep the well flowing. Unlike conventional gas lift, this is called “Poor boy”, as it doesn’t involve a packer and gas lift valves. Compressed gas flows in the casing annulus and then enters the bottom of the open ended tubing, to help the formation gas lift the water to the surface. For wells that are not strong enough to unload themselves swabbing may be necessary to establish flow. Once steady tubing flow is achieved then either the casing pressure or the flowing tubing pressure is monitored.
- Water disposal: Water disposal is a major problem associated with producing ECBM wells in the Netherlands. Coal gas wells usually produce higher volumes of water initially 1.5 to 15 m^3/d (10 to 100 b/d) with water volumes decreasing with time. Coal water contains predominantly sodium

bicarbonate, which forms scales. These waters can be disposed into evaporative pits or in disposal wells. Disposal wells are an attractive alternative to surface pits. Their capability exceeds produced water volumes, but their quality must meet Environmental Protection criteria, including compatibility with formation waters and the ability to take large volumes of water.

Some economical issues related to CO_2 –ECBM injection and production

Most ECBM operations employ primary recovery methods, generally pumping off large volumes of formation water to lower reservoir pressure and allow methane desorption from the coal. Primary recovery methods recover only 20 to 60% of original gas in place. Injecting CO_2 into methane bearing coal seams, and remains sequestered within the seam, is based on the principle that CO_2 adsorbs more readily, and preferentially onto the coal matrix compared to methane. For example; the CO_2-injection rate at each injection well in the Allison Unit field (San Juan basin) was around 20,000 m^3/day for more than 3 years with minimal CO_2 breakthrough in the production wells (Stevens and Pekot 1999). The methane is simultaneously desorbed and thus can be recovered as a free gas. Laboratory isotherm measurements (Wolf et al. 1999a) demonstrate that coal can adsorb roughly twice as much CO_2 by volume as methane, this leads to the working assumption that the ECBM process stores 2 moles of CO_2 for every 1 mole of methane desorbed. Hydraulic fracture stimulation is used to assist recovery, and CO_2-ECBM is used to recover a larger fraction of gas in place.

ECBM development is considered as a high -risk venture, due to the great variability in reservoir parameters namely gas saturation and permeability. The existence of the oil industry supports efficient drilling and production operations and consequently their knowledge might help to reduce development costs. Besides the expensive costs for drilling wells and field development, the wellhead price for methane and cost for CO_2 will depend on pipeline infrastructure.

Some of the risks involved during ECBM project developments (EPA 1997) are:

- indication of marginal gas resource – quality, rate of flow, and longevity,
- inability to negotiate energy sale agreements.
- inability to negotiate CO_2 sales agreements, including CO_2 –quality and constant supply.
- inability to secure financing

The risks involved after project financing are:

- cost overruns during construction or operation
- poor gas productivity (flow rate, and quality)
- poor system performance
- drops in revenues due to price changes

Risk seeking investors accept more of the risk that a project will perform poorly; in return, however they enjoy the upside potential to earn large returns if the project performs well. In addition, the involvement of local or (inter)national authorities could give a boost in field developments, when eco-incentives on greenhouse gases are becoming an issue.

Annex I Discussion on drilling costs

F. van Bergen (TNO-NITG)

From the economical evaluation it appeared that the most important cost factor for an ECBM-CO_2 project are the costs of drilling. The costs of drilling are very variable and depend on time, location, and economy of scale. The time dependency is due to the dependency on the oil and gas market, which is highly fluctuating. The location dependency is due to local prices of equipment and raw materials, but also on locally dependent additional costs such as permits, environmental legislation, etc.
Factors that affect costs are the scale of operations, the competitiveness of the service industry, the remoteness of operations from supply bases, the maturity of the technology and the combined complexity of the technology and field conditions (i.e. deep, high pressure wells will cost more to drill and more to frac; Massaratto 1999).

In the Netherlands onshore the cost level for drilling, completion and stimulation costs are relatively high compared to other parts of the world. Costs of (E)CBM programmes will be extra high because of the R&D nature of these programmes, which causes the costs to be significantly higher than mature USA CBM regions (San Juan, Black Warrior, and Powder River Basins; Massaratto 1999). In a later stage the drilling costs will be reduced, among others by the economy of scale concept.

Massarotto presents drilling, completion, and stimulation costs for Australian and New Zealand coalbed methane wells and made a comparison between these costs and international costs from the USA, Canada and China. The following data were deduced from the publication of Massaratto:

Table I-1. Coalbed methane well costs at various locations (Massaratto 1999).

Location	**Depth (m)**	**Costs (€)**	
Canada (Hatton)	550	79000	With stimulation
Canada (Athabasca)	680	157000	With stimulation
Canada (Pelican)	690	116000	No stimulation
Canada (Stettler)	1330	242000	No stimulation
US (Powder River Basin)	243	64000	No stimulation
US (Black Warrior Basin)	915	272000	With stimulation
US (Washington State)	600	398000	With stimulation
China	400	115000	With stimulation
New Zealand	472	675000	With stimulation
New Zealand	570	716000	With stimulation
Australia	900	497000	With stimulation

Based on this table the following graph was constructed:

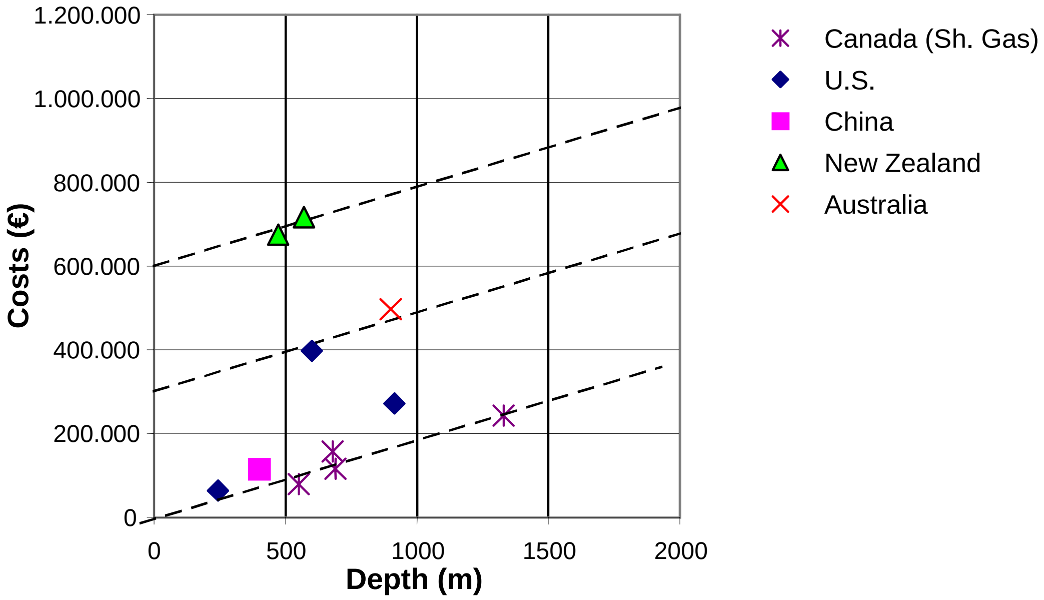


Figure I-1. Comparison of drilling, completion and stimulation costs vs. depth of Canada, U.S., China, New Zealand and Australia. A low, most likely, and top cost line is drawn in the figure (modified after Massaratto 1999).

Figure I-1 shows that the costs for drilling, completion and stimulation are lowest in Canada. This is due to the scale of the operations in the area (over 1000 wells per year in low pressure gas reservoirs), the incentives of competition between service companies and contractors, and time to continuously improve all facets of design and operations. The costs of the mature U.S. basins are somewhat higher than the Canadian costs, that of the Washington state well are higher due to the remote character. The costs in China are in line with the U.S. costs, implying an anticipation of economy of scale and focused use of technology. Some lower costs in China (e.g. labor) are probably offset by costs for imported technology and equipment, with associated higher mobilisation/demobilisation costs (Massaratto 1999). The Australian costs are higher due to the premature stage of the CBM industry. Especially stimulation costs are very high. In New Zealand the costs of drilling are also high because of premature CBM industry, but on top of that the completion and frac jobs are extremely costly due to the remote character of the area and related high mobilisation/remobilisation costs (Massaratto 1999).

Based on these data three lines are drawn in the graph, representing the low, most likely, and top cost line for the Netherlands. The lowest possible costs that would be possible in the Netherlands, assuming large-scale operations, will never be lower than in the Canadian Alberta basin. The most likely cost scenario is assumed to be in line with the current Australian costs, the top costs will resemble the remote New Zealand area. The cost for a 2000 m well in the Netherlands is thus, based on this limited information, estimated for the low, most likely, and high case to be respectively 375000, 675000, and 975000 € respectively.

This is in line with the costs for an experimental CBM well in Germany (pers. com. Dr. Kretzschmar, DBI GUT), that amounts up to 2000000 DM (= € 1000000).

In Poland, the lowest drilling costs are estimated at (Central Mining Institute Katowice, personal contact) 200-275 € per meter, implying drilling costs of 400000-550000 € for a well of 2000 m depth. This seems, taking into consideration the costs differences between Poland and the Netherlands, to be in agreement with the estimations for the Dutch situation.

In the coal inventory project in the mid-eighties (Krans 1986) five wells were drilled for coal exploration in the period from 1982-1985. The costs for one well, with a rock cover of 900 m and an enddepth of 2000 m, were estimated as follows:

Drilling	€	815,000[*]
Construction of drilling location	€	45,000
Removal of drilling fluids	€	34,000
Insurance	€	23,000
Drilling costs	€	917,000
Well logs	€	91,000[†]
Total costs	€	1,008,000

The numbers of (Krans 1986) indicate that, also taking into consideration the inflation, the drilling costs estimated on the basis of the international data are probably too low. However, these costs were based on 6 wells only. We expect that the economy of scale will reduce the drilling costs significantly. (Massaratto 1999) concludes that the costs for a large-scale Australian CBM industry would come down to about 125 – 140 % of the costs of the mature US areas, whereas they are now about twice as high.

On the other hand, the development of these kinds of projects in the Netherlands always faces relatively densely populated areas. Any ECBM-CO2 project requires both production and injection wells. Since the maximum distance between the injection and production well is about 1 km , this would results in many wells in a limited area. In the Netherlands this will be non-acceptable, thus demanding solutions.

One of the solutions could be drilling under an angle from one point (Figure I-2). This concept has however, to our knowledge, never been applied in the CBM industry up to now. Obviously, the costs for such an operation will be increased due to the increasing complexity of this type of multilateral wells. Costs estimations, which will also depend on the economy of scale, are difficult. At this point it is not possible to give any estimation of the cost increment related to the application of this new technique.

In a potential follow-up study, a thorough evaluation of drilling costs and techniques for the Dutch situation is strongly advised.

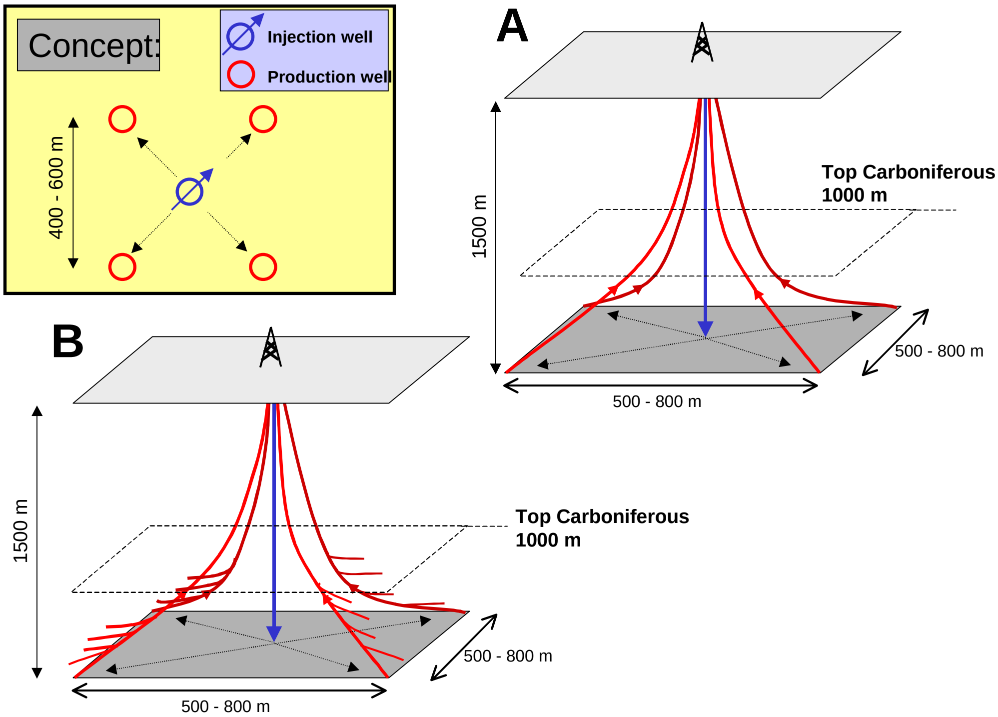


Figure I-2. Concept of a five-spot ECBM-CO2 project that is drilled from one location, one with (top right) and one without (lower left) in-seam drilling of the coal seams.

---

[*] Based on a 1986 tender of a German drilling firm. Price includes 19% B.T.W. and B.O.P.-rent. Casing (only in rock cover): 103/4" (stove pipe), first 30 m; 7 5/8" casing up to a depth of 500m; 5 ½ " caing up to a depth of ± 900 m (Top Carboniferous)

[†] The amounts of the well logs vary strongly per well, because they are, a.o., depth dependent and the logging prgramme will not always be completely executed

Annex J State of the art in hydrogen production

G.J. Ruijg (ECN)

For production of hydrogen from methane three methods are commercially available (Mozaffarian 1994):

- Steam reforming
- Thermal cracking
- Partial oxidation

The first two technologies are suitable for ECBM applications because pure carbon dioxide is co-produced which can be injected on the spot, in thermal cracking the co-product is carbon black. CO_2 Dilution of methane (frequently occurring in ECBM gas) has hardly any influence on the systems, except for a lower speed of reaction.

Steam Methane Reforming (SMR)

Hydrogen is currently produced primarily by the steam reforming of natural gas. The process basically involves a catalytic conversion of the hydrocarbon and steam to hydrogen and carbon oxides. A simplified basic flow diagram of the steam reforming process is shown in Figure J-1. The process consists of three main steps:

- synthesis gas generation;
- water-gas shift;
- gas purification.

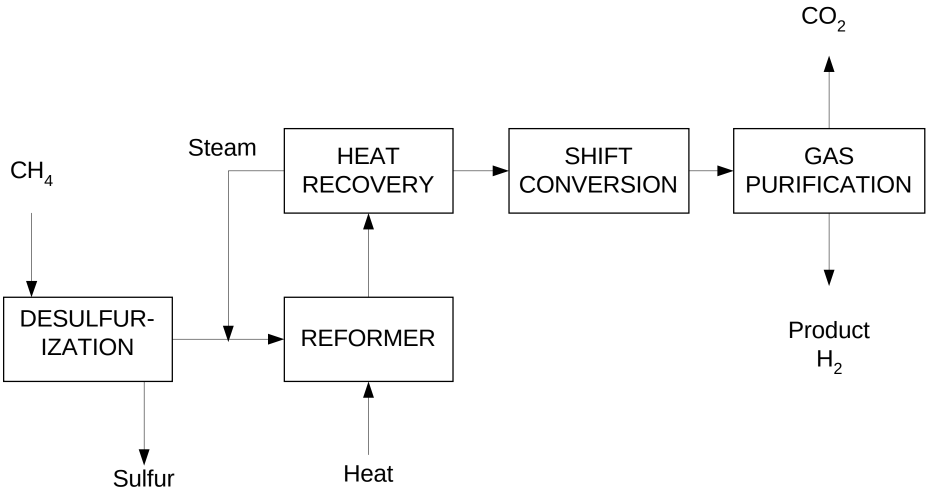


Figure J-1. Steam Reforming Process (Mozaffarian 1994).

To protect the catalysts in the hydrogen plant, the hydrocarbons have to be desulphurised before being fed to the reformer. The desulphurised feedstock is then mixed with process steam and reacted over a nickel-based catalyst contained inside of a system of high alloy steel tube. The following reactions take place in the reformer (Steinberg and Cheng 1989):

$$CH_4 + H_2O \Leftrightarrow CO + 3H_2 \quad \text{Equation J-1}$$

$$CO + H_2O \leftrightarrow CO_2 + H_2 \quad \text{Equation J-2}$$

The first reaction is highly endothermic. Heat must be added at temperatures of 600 to 800 °C.. About 30% of the methane is used for firing the reformer. After the reformer, the process gas mixture containing CO and H_2 passes through a heat recovery step and is fed into a water-gas shift reactor to produce additional H_2. The cold raw gases next passes through gas purification units to remove CO_2, the remaining CO, and other impurities to deliver the desired purified H_2 product. Traces of CO remaining in the H_2 stream after CO_2 removal are catalytic oxidised to CO_2. This is done because the processes which use the hydrogen, such as Solid Polymer Fuel Cells, are not tolerant to CO.

A special opportunity is the use of the pressure swing adsorption (PSA). This process reduces the number of unit processes and complexity of the operation by replacing the low-temperature shift, CO_2 removal and methanation with a PSA process unit. In this process, the raw gas is passed through a series of beds of molecular sieves of activated carbon, where all components except H_2 are preferentially absorbed. The beds are regenerated by adiabatic depressurisation at ambient temperature. The purge gas, which contains water vapour, CO_2, CO, and CH_4, is then fed to the furnace for supplying heat to the reformer. The purity of H_2 from the PSA system can be 99% or higher, and can thus be used for a wide variety of chemical and petrochemical processes (Steinberg and Cheng 1989). Every mole methane produces 2.8 mole hydrogen (Katofsky 1993).

Investment costs in a steam reformer hydrogen plant vary from 7000 €/(m^3CBM/h) for a plant with a capacity of 4 thousand m^3CBM/h to 2500 €/(m^3CBM/h) for a plant with a capacity of 100 thousand m^3CBM/h (Gregoire Padró and Putsche 2000). It means that a small sized SMR plant is almost 3 times as expensive than an installation to upgrade CBM to natural gas quality of the same capacity.

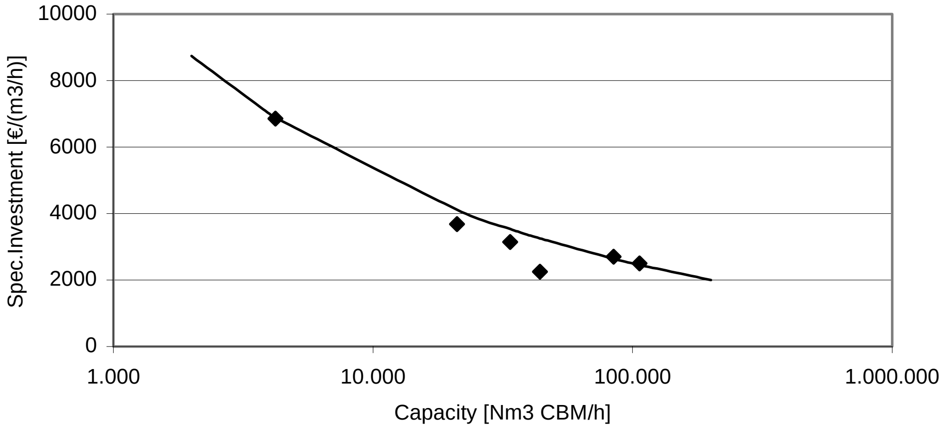


Figure J-2. Specific investment of SMR Hydrogen plants.

The investment costs of SMR hydrogen plants can be expressed with:

$$I = C \times v^R \times f_1 \qquad \text{Equation J-3}$$

with I = investment in M€
C = constant = 0,085 M€
v = design CBM flow in m^3/h
R = scale factor = 0.68
f_1 = currency inflation factor from US$_{1997}$ to €$_{2000}$ = 1.3

Annual operation and maintenance costs are 5% of the investment costs. Auxiliary energy use is 0,2 kWh/m^3 CBM (Blok et al. 1997).

The cost of feedstock, which makes up 60% of the total production cost, has a significant effect on the hydrogen production cost. Future hydrogen prices are therefore heavily dependent on the trend in future feedstock prices (Mozaffarian 1994).

Partial Oxidation (POX)

The partial oxidation of coal bed methane involves basically the conversion of steam, oxygen and hydrocarbons to hydrogen and carbon oxides. The process proceeds at moderately high pressures with or without catalyst depending on the feedstock and process selected. The catalytic POX, which occurs at about 590°C, will work with feedstock's ranging from methane to naphtha. The non-catalytic POX, which occurs at 1150-1315°C, can operate with hydrocarbons including methane, heavy oil and coal. POX is often referred to as gasification when coal is the feedstock. The Catalytic Partial Oxidation (CPO) process is considered for ECBM applications.

Compared to steam reforming, CPO requires additional facilities such as an air separation plant to provide oxygen[*], as well as a larger shift and a separation train. The following reactions take place (Steinberg and Cheng 1989):

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2 \qquad \text{Equation J-4}$$

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad \text{Equation J-5}$$

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \text{Equation J-6}$$

A simplified basic flow diagram for hydrogen production by partial oxidation is shown in Figure J-4.

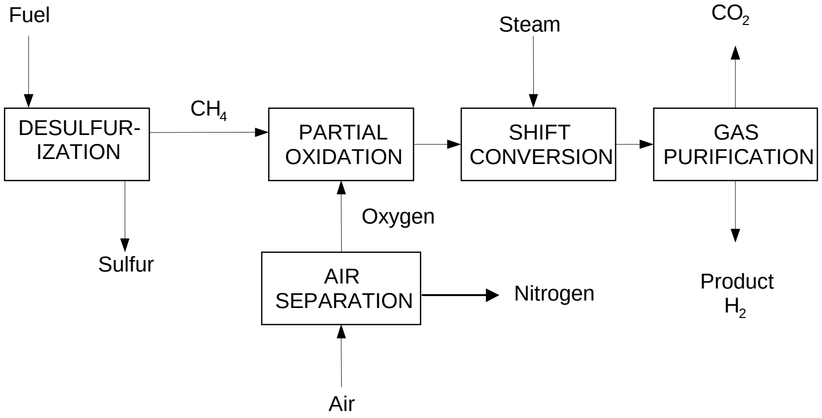


Figure J-4. Partial Oxidation Process (Gregoire Padró and Putsche 2000).

In the synthesis gas generation step, the hydrocarbon feedstock is partially oxidised with oxygen. The carbon monoxide is shifted with steam to produce CO_2 and H_2.The shift reaction and gas purification processes following the CPO unit are similar to those for steam reforming, but relatively of larger size.

The hydrogen production cost is higher than for steam reforming of methane. The hydrogen production cost is very sensitive to the capital cost, which accounts for 48% of the overall production cost. The CPO reactor is less expensive than the steam reformer. However, the cost of the oxygen plant, the additional costs of the desulphurisation steps and the larger shift reactor make such a hydrogen plant capital intensive (de Biasi 1999). Data on economics of hydrogen technologies which are derived for hydrogen production from coker off-gas indicate that installations based on non-catalytic partial oxidation have same prices for comparable sized as SMR installations. However the total efficiency of POX plants is lower than the efficiency of SMR plants, which makes SMR plants the favourable technology (Schaeffer 1998).

When steam is added to the reforming process the technology is called Catalytic Autothermal Reforming (CAR). The process combines partial oxidation and steam reforming in a single reactor, where the heat for the endothermic reforming reaction is delivered by the partial oxidation reaction of methane. The CAR reactor is followed by a gas-water shift reactor and a gas purification unit. The last two unit operations can be replaced by Pressure Swing Absorption units, in which the remaining CO is shifted to CO_2 and the hydrogen is purified.

A catalytic autothermal reactor with gas purification by pressure swing absorption is a fairly simple system. It might become a better option for CBM utilisation than SMR, especially in the smaller sized hydrogen plants.

---

[*] The difficulty in separating nitrogen from hydrogen to produce a pure product necessitates the use of pure oxygen in partial oxidation processes (Steinberg and Cheng 1989).

Annex K Fuel Cell prospects

G.J. Ruijg (ECN)

A fuel cell is an electrochemical device in which the chemical energy that is released at the oxidation of a fuel is directly converted to electrical energy. Main component is the electrolyte, which dependent of the type conducts certain ions, but no electrons. One side of the electrolyte is exposed to fuel (the anode), the other side (the cathode) to air. Oxidation takes place by ion transport through the electrolyte. So the fuel and therewith the carbon dioxide remains separated from the air by the electrolyte, what makes sequestration of CO_2 from fuel cells very easy. Therefore fuel cells are a good option for application at the wellhead to convert CBM directly into electricity and reinject the CO_2 in the CBM field.

Fuel cells are distinguished by their type of electrolyte in Phosphoric Acid Fuel Cells (PAFC), Molten Carbonate Fuel Cells (MCFC), Proton Exchange Membrane Fuel Cells (PEMFC, also called solid polymer fuel cell SPFC) and Solid Oxide Fuel Cells (SOFC). For stationary applications the MCFC and SOFC are favourite. Molten Carbonate Fuel Cells have the disadvantage over Solid Oxide Fuel Cells that at the air side (cathode) CO_2 must be supplied together with the air. In an SOFC spend fuel and air streams are not diluted, what makes the capture of CO_2 easier. The exhaust gas from the cathode of the SOFC is air with a lowered oxygen content. The exhaust gas from the anode contains only non-utilised fuel components, inert gasses from the fuel, carbon dioxide and water. After separation of the non-utilised fuel and the inert gasses, the gas can be dried and compressed for reinjection in the coal bed. The non-utilised fuel can be redirected to the inlet of the fuel cell anode.

All types of fuel cells are at an early stage of development. The largest SOFC demonstration unit is located at Westervoort, the Netherlands, since 1998. It has a power output of 110 kW_e. The electrical efficiency is about 45%, and investment costs were over 5000 €/kW_e.
Future developments are hybrid systems in which SOFCs are integrated with gas turbines. Advantages of hybrid systems are lower investment costs per kW_e than pure fuel cell systems, and often higher efficiencies! Power outputs will go up to 10 MW_e, and electric efficiencies can go up to 70% LHV. DoE in the USA expects these systems to reach a price level of 1000 €/kW_e in the period 2010-2015 (OECD 1996). Studies based on technology dynamics show that the level of 1500 €/kW_e might be in reach in 2003 (1996).

The solid oxide fuel cells are hardly sensitive to dilution of the fuel with carbon dioxide. System studies show that a 50% mole concentration of CO_2 in the fuel stream causes a 5% drop in power output, and no effect on the efficiency of the fuel cell. The overall efficiency will drop, because the power of the CO_2 compressor will double.

Annex L Economic parameters

All cost numbers used in this report are in €$_{2000}$ unless indicated otherwise. The following assumptions have been made:

- 1 €$_{2000}$ = 0.95 US\$$_{2000}$
- Annual US GDP deflation in period up to 1994 is determined from OECD (1996) numbers. In period 1994 to 2000 a GDP deflation of 2.5% is assumed.
- Annual EU GDP deflation in period 1994 to 2000 is 3.0%
- Price of steam = 0.02 €/kWh
- Price of electricity = 0.05 €/kWh
- Price of natural gas = 0.03 €/m^3
- Interest rate for CO_2 capture, drying and compression installation is 5 %.
- For transportation pipelines the interest rate is 5%; a depreciation period of 20 years is used.
- The interest rate for ECBM projects is 10%.

Annex M Glossary

BHP	=	Bottom hole pressure; Prevailing pressure at well bottom
CHP	=	Combined heat and power
ECBM	=	Enhanced coalbed methane
GIP	=	Gas in place
GSC	=	Gas sorption capacity
PGIP	=	Producible gas in place
SOFC	=	Solid oxide fuel cell

Completion factor	=	Fraction of the net cumulative coal thickness within the drilled strata that will contribute to the gas production. Depends on the thickness of the separate coal seams, the distance between the coal seams and the application of stimulation techniques
Differential pressure	=	Lithostatic stress minus pore fluid pressure
Lithostatic Pressure	=	Prevailing pressure in the rock or coal
Permeability	=	Extent to which the fluid can access the pores
Pore fluid pressure	=	Hydrostatic pressure; Pressure due to water column
Porosity	=	Spatial fraction of rock that can be accessed by the fluid
Recovery factor	=	Fraction of gas that can be produced from a contributing coal seam. Depends strongly on the pressure drop that can be realised by pumping of large volumes of water
Sweep efficiency	=	fraction of producible CBM swept from the coal layer