
Introduction

The Alberta Research Council, Inc. (ARC) of Alberta, Canada, led a group of provincial, national and international organizations to exploit coalbed methane (CBM) by testing a novel process of injecting carbon dioxide (CO2) into Alberta’s vast, deep, unmineable coal beds to release the trapped methane. This process is called Enhanced Gas Recovery (EGR) or Enhanced Coalbed Methane (ECBM) and is similar to the popular practice of using CO2 injection to enhance production from oil reservoirs. With coal-based EGR, the injected CO2 is adsorbed in the coal and stored in the matrix of the coal seams, releasing the trapped methane into the coal cleats that can be produced and sold for profit.

Future work in this area can lead to the design of efficient null-greenhouse-gas emission power plants that are fuelled either by mineable coal or by the methane released from the deep coal reservoirs. In this closed CO2 process, the waste CO2 produced from the coal burning or methane-burning power plants is injected into the CBM reservoirs to produce more methane, and the cycle continues. In addition, a geological sink is established in the coal beds, virtually eliminating any release of CO2 to the atmosphere. In the future, bacterial processes using coal as an energy source may be developed to convert the CO2 back to methane, thus extending the cycle and making it sustainable. An abundance of deep coal beds in Canada and the USA makes geological storage of CO2 applicable to many areas in North America where coal-burning power plants are located.

ARC is not the first to pilot this process. Burlington Resources has successfully injected CO2 into relatively high permeability coalbeds in the San Juan basin in the USA. They are stimulating coalbed methane production and recovery. The injected CO2 is adsorbed into the coal matrix and remains in the ground after completion of gas production. However, further testing and demonstration are needed to apply this process to low permeability reservoirs such as those found in Alberta, Canada and elsewhere in the world.

Summary

The ARC-led project had two main objectives:

• to reduce greenhouse gas emissions by subsurface injection of CO2 into deep coalbeds; and

• to enhance coalbed methane recovery factors and production rates as a result of CO2 injection.
The overall program was divided into five phases:

I. The proof of concept study – initial assessment and feasibility of injecting carbon dioxide, nitrogen and flue gases into the low permeability bituminous Mannville coals of Alberta.

II. The design and implementation of a CO2 micro-pilot test following Amoco Production Company procedures.

III. The design and implementation of flue gas (CO2 + N2) micro-pilot tests.

IV. Source – sink matching, simulator improvements and economic assessment model.

V. Extension of micro-pilots to lower rank bituminous and higher rank anthracitic coals

Each phase followed four steps:

i. The Resource: To characterize the resource properties of Alberta CBM reservoirs and identify the best geological site for a multi-well pilot.

ii. Enhanced Production: To assess the CBM reservoir response to injected flue gas compositional changes.

iii. Reservoir Simulation Software: To improve the predictive capability of ECBM reservoir simulators.

iv. Surface Facilities: To identify flue gas sources and calculate the cost of enriching the CO2-component of the flue gas supply and delivery to the CBM reservoir.

An iterative process is used combining the data collected from these four steps to complete an economic evaluation of the CO2-ECBM recovery process in order to justify multi-well pilot demonstrations.

**Phase I (1997-1997)**

A paper study was completed to see if injected gases (CO2) would stay in a deep coal seam (Mannville at 1260 meters) while enhancing CH4 production. Computer modeling indicated that this was possible. Results also showed reservoir storage from two to three times the amount of CO2 injected versus CH4 produced in a coal seam. Based on the success of Phase I, the project passed the first go/no-go decision and proceeded to Phase II.
Phase II (1997-1999)

Phase II was comprised of three tasks: (1) geology, geotechnical and engineering, (2) numerical modelling, and (3) a micro-pilot field test.

The field test was carried out in an existing Gulf Canada well at Fenn-Big Valley, Alberta. The test consisted of a CO₂ injection/soak/production single well test and was designed to meet three primary goals. The first goal was to accurately measure data while injecting CO₂ into and producing CO₂ and methane from a single well using a “Huff and Puff” strategy. The second goal was to evaluate the measured data to obtain estimates of reservoir properties and sorption behaviour. The third goal was to use simulation models to predict the behaviour of a large scale pilot project or full field development. This phase is a preliminary and necessary step leading to the planning of a full-scale 5-spot pilot test.

The field test was a success. Results supported the conclusions of Phase I, showing substantial enhanced methane production as a result of CO₂ injection (see Figure 1). All three primary goals established for the test were met. The first goal was met as the data set that was collected is of high quality. The second goal was met as the data were evaluated to obtain accurate estimates of reservoir properties and sorption behaviour. The third goal was met as simulation models were used to conclude that a full-scale pilot CO₂ - EGR project is technically possible at the Fenn-Big Valley location but not currently economic. Phase II was successfully completed in April 1999.

Figure 1. Primary, nitrogen and carbon dioxide injection scenarios for enhanced coalbed methane recovery at Fenn-Big Valley. Injection is at constant flow rate. Production rate is normalized.

Phase III (1999-2001)

Based on Phase II results, the project passed the second go/no-go decision and proceeded to Phase III. We began the 1999/2000 efforts by evaluating options for the treatment of flue gases, compression, and the associated economics to optimize CO₂ storage and
methane production both at the pilot and commercial scales. Then we drilled and completed a second well and performed a simulated flue gas micro-pilot test. This was the world’s first pilot test of injecting flue gas into coal seam.

In October 1999, the second well was successfully drilled and completed at Fenn-Big Valley in the Mannville coals. Core samples were collected to allow accurate determination of the gas-in-place value, gas composition, and gas storage capacity. Two micro-pilot tests were performed on the new well in the spring of 2000, one by injecting pure nitrogen and the other by injecting a 50/50 mixture of CO$_2$ and N$_2$. Meanwhile, in the original well a simulated coal-fired flue gas was injected by using the exhaust from a compressor engine used for underbalanced drilling (flue gas composition 13% CO$_2$, 87% N$_2$). The combination of nitrogen and carbon dioxide may result in greater hydrocarbon recovery without maximizing carbon dioxide sequestration. The results of these micro-pilot tests were used to design a multi-well pilot to be installed in the future phases of development.

In terms of the numerical modelling tool, the three software products evaluated were adequate for predicting primary production of coalbed methane. However, only one was suitable for modelling flue gas injection. None of the reservoir simulation software products were capable of accurately predicting the produced gas composition observed during the field test. Improved understanding of the process mechanisms, for example, multiple gas sorption and diffusion, and changes in coal matrix volume due to sorption or desorption of CO$_2$, was needed to guide the future development of the simulation models.

A surface facility spread sheet was developed to better assess the cost of capture of CO$_2$ from flue gas streams.

In parallel, during 2000, geological studies were carried out to evaluate the geology the Edmonton Group coal deposits in Alberta. The Edmonton coals are located at shallower depths and may be more permeable than the Mannville coals, and are in close proximity to major power plants and would be convenient for CO$_2$ sequestration. The reservoir properties of these shallower coals, in particular the natural fracture permeability, cannot be determined by the study of available geologic data. As a result, four formation evaluation wells were drilled into the Horseshoe Canyon and Ardley coals.


Based on Phase III results, the project passed the third go/no-go decision and proceeded to Phase IV. In Phase IV, the project was expanded to include the response of CBM reservoirs to sulfur gases to further evaluate injection of acid gases (CO$_2$ and H$_2$S) into deep coals. Methods of modeling permeability changes due to swelling strain were added to the CMG (Computer Modelling Group) commercial GEM compositional numerical simulation model, and along with the existing pressure stain permeability modifiers have increased the accuracy of history matching and forecasting of the enhanced recovery. The economics of enhanced coalbed methane (ECBM) recovery were further refined by optimizing the process using the improved numerical simulators and linking it to the
surface facility economic model (i.e. the Integrated Economic Model for IEM). In parallel, matches of 12 types of CO2 sources with CBM reservoirs were made for Alberta aid in planning for the future.

**Phase V: CSEMP (2004 – 2009)**

A Suncor-led consortium with ARC in charge of the research component of the project (entitled CSEMP which stands for CO2 Storage and Enhanced Methane Production) conducted a micro-pilot in the lower rank shallower Ardley coals of Alberta. Once underway the project was delayed due to regulatory hurdles due to the shallow depth of the coal seam. Over 1000 tonnes of CO2 were injected into a micro-pilot and two well pilot. Extensive monitoring of the micro-pilot and pilot were completed using a combination of downhole pressure gauges (external to the casing, located in the coals and in an aquifer directly above the coal seam), seismic, tiltmeters, shallow water wells and atmospheric monitoring. Extensive history matching allowed a conceptual commercial project to be developed. It was concluded that the Ardley coal was not as attractive as the higher rank Mannville coal for production of methane. This was due to the shallower depth of the Ardley containing lower gas-in-place and being of lower rank requiring more CO2 to displace an equivalent amount of methane.

**Conclusions**

Since it takes at least two cubic feet of CO2 for each cubic foot of methane produced from the Mannville, the CO2 cost would take up more than $2 US of the gas price on a per thousand cubic feet of methane basis (assuming CO2 at $1 US per thousand standard cubic feet or $19 US per tonne.) Alternately, flue gas (which comprises mainly of nitrogen and carbon dioxide) injection has its merits. From an economic perspective, flue gas injection offered better economics than pure CO2 injection (unless there is a credit for CO2). Flue gas injection appears to enhance methane production to a greater degree possible than with CO2 alone while still sequestering CO2, albeit in smaller quantities. The CO2 will remain sorbed in the coal while the majority of the nitrogen will be produced along with the hydrocarbons. In this case, however, the process will require an extra processing step of rejecting the N2 from the produced gas stream. Therefore, considering both economic and CO2 sequestration factors, there might be an ideal CO2/N2 composition where both factors will be optimized. Technical issues that need to be addressed in the next phase of the development include flue gas conditioning, compression and delivery, N2/CH4 separation and improvement of the numerical reservoir simulators.

**ARC’s Outlook to the Future for CO2-ECBM Research and Piloting**

Currently, there are a number of commercial reservoir models which use coal swelling algorithms similar to that developed by ARC to model the dynamic permeability changes that take place during a CO2-ECBM project. Although these simulators yield much more accurate results than those that only consider pressure strain to affect the permeability, there is still an important permeability component missing: that due to shear failure. In high permeability reservoirs, hydro fracturing (a technique which imposes new stress...
fields around a well as a result of high rate injection) has been utilized for many years in the oil and gas industry to create a high permeability planar fracture extending past areas of formation damage to enhance production. However, in low permeability reservoirs, the nature of the induced stress field should be that which promotes shear failure over a volume (termed Domain Stimulation). Domain stimulation technology has allowed industry to commercialize gas production from low permeability gas shales and tight sands. It should also apply to coals. Simulators need to be able to predict shear failure and the effect it has on permeability in order to move marginal CO$_2$-ECBM projects to commerciality. ARC currently has a joint industry program (JIP) which has developed a Domain Stimulation software model and is developing permeability correlations for this.

Additionally, the promise of CO$_2$ credits allowing marginal projects to become commercial needs to be evaluated. Although a CO$_2$-ECBM project might not currently be commercial, it could be in the future as CO$_2$ credits become more valuable. Any economic assessment needs to take this into account. A fast screening tool is needed which evaluates the integrated CCS process. In this regard, ARC, in partnership with Energy Navigator, is further developing the Integrated Economic Model for CCS as a software package which allows scenarios to be evaluated rapidly with respect to capture, transportation and storage through ECBM or in aquifers.

At all coal ranks, CO$_2$ is more selectively absorbed on coal compared to methane. At low ranks, the selectivity is higher (i.e. 10 to 1 for lignite compared to 1.2 to 1.0 for anthracite). However the sorption capacity for methane increases rapidly with rank. Therefore, anthracitic coals, which have similar permeability to low rank coals, are the most attractive candidates because they have a higher methane content and they will sorb less CO$_2$ per molecule of methane produced although the absolute amount of CO$_2$ sorbed is similar to low rank coals. Anthracitic coals have been identified in the Shanxi Formation in the Qinshui basin of China which are an attractive target. This has been confirmed from a micro-pilot conducted by ARC in partnership with CUCBM (China United Coalbed Methane Corporation). Currently, CUCBM is working with several international companies to develop this into a full scale pilot with ARC as the technology provider.

Finally, there is concern about the contamination of the coal resource with CO$_2$, if at some future date, the coal is to be mined. ARC has been working on microbial regeneration of CBM reservoirs and conversion of stored CO$_2$ to methane. Both processes involve the injection of nutrients and/or methanogenic consortia into the coal beds. Under appropriate growth conditions, methanogenic consortia can generate significant quantities of methane over a relatively short time period in the subsurface by subtracting energy and hydrogen from the coal as illustrated in Figure 2. The process effectively converts the coal and the CO$_2$ to methane which can lead to an increase in permeability due to the consumption of a small fraction of the coal. This leads to a more effective primary production of the CBM in later cycles. If the coal resource was to be mined in the future, the final cycle would end at the degasification step of primary CBM production after all the CO$_2$ had been converted to methane.
Consequently, ARC would predict a bright future for CO₂-ECBM. It not only adds to our reserves of natural gas which is the cleanest burning fossil fuel, but it also can help reduce release of GHGs to the atmosphere by trapping the injected CO₂ in the coal seams on a geologic time scale.

**Project Related Publications**

*Enhanced Coalbed Methane Recovery*


**Enhanced Coalbed Methane: Methanogenesis**


**Enhanced Coalbed Methane Recovery: Numerical Model Comparison**


