

**A Numerical Investigation into the Potential to Enhance Natural  
Gas Recovery in Water-drive Gas Reservoirs through the Injection  
of CO<sub>2</sub>**

**Myles L. M. Regan**

**A thesis submitted for the degree of  
Doctor in Philosophy in Petroleum Engineering**

**Australian School of Petroleum  
The University of Adelaide**

**December 2010**

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## Abstract

The injection of carbon dioxide (CO<sub>2</sub>) into oil reservoirs for the purpose of enhancing recovery has been performed for decades. Conversely, the injection of CO<sub>2</sub> into natural gas reservoirs has received very little attention, primarily due to the typically high recovery achievable under primary depletion. This high recovery is however associated with volumetric gas reservoirs only. If the reservoir is in the presence of an active water-drive, recovery can be considerably lowered. This is caused by pressure maintenance and the trapping of gas, rendering a volume of gas immobile. Consequently, any technique that reduces reservoir pressure and/or retards the influx of the aquifer will enable natural gas recovery to be enhanced.

In this thesis, the injection of CO<sub>2</sub> has been proposed as a method of retarding the influx of the aquifer. Favourable fluid properties between the injected CO<sub>2</sub> and natural gas also allow the displacement of natural gas towards the production wells with minimal mixing. This thesis investigates the nature of the effects of a number of parameters deemed potentially influential on the displacement of natural gas by CO<sub>2</sub> and the ability to produce and enhance recovery with as low a producing CO<sub>2</sub> concentration as possible. Parameters chosen include uncontrollable reservoir and fluid properties such as permeability, thickness, diffusion coefficients and salinity. Controllable factors are also investigated, such as the timing of injection, production and injection rates and the type of wells employed. This investigation was conducted through the use of numerical simulation. Simulations were first performed on a simple, conceptual model in order to understand the key processes involved in the CO<sub>2</sub> enhanced gas recovery process. The results of these studies were then applied to a more complex numerical investigation involving a model of the Naylor gas field.

The results of the initial studies found that the parameters which determined the extent of viscous and gravity forces, such as permeability, thickness and formation dip, were the most influential in determining the stability of the displacement, and consequently the recovery achievable at the breakthrough of CO<sub>2</sub> at the production well. The fluid properties, such as water salinity and the diffusion coefficient, were found to have less of an impact than the reservoir properties. Efficient displacement in a non-dipping reservoir was possible with either viscous or gravity dominated displacement, while only gravity stable displacement was preferred in a dipping reservoir. The primary recovery efficiency did however dictate where the injection of CO<sub>2</sub> should be targeted in order to achieve incremental recovery with the lowest producing CO<sub>2</sub> concentration. Due to the low primary recovery efficiency, the injection of CO<sub>2</sub> should be targeted in high permeability, non-dipping reservoirs.

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The presence of heterogeneity accelerated the breakthrough of CO<sub>2</sub>, and so it was shown that delaying the injection of CO<sub>2</sub> was beneficial in maximising the recovery at the initial breakthrough of CO<sub>2</sub>. However, once CO<sub>2</sub> had reached the production well, the rate of increase in CO<sub>2</sub> production was considerably more rapid if injection was delayed. The choice of the timing of injection and the ability to maximise incremental recovery is therefore heavily influenced by the maximum allowable producing CO<sub>2</sub> concentration, which will be determined by the economics of the project. The investigation into the other controllable parameters showed that the operational strategies which either lowered the susceptibility for CO<sub>2</sub> to cone into the production well, or which mitigated against the uneven advancement of CO<sub>2</sub> due to heterogeneity were preferred.

Ultimately this study showed that the injection of CO<sub>2</sub> can effectively retard the influx of the aquifer and efficiently displace natural gas towards the production well. By understanding the mechanisms involved in this displacement process, operational parameters can be optimised accordingly to maximise natural gas recovery with the lowest producing CO<sub>2</sub> concentration. The extent of incremental recovery is subsequently determined by the maximum producing CO<sub>2</sub> concentration allowable, as determined by the economics of the project.

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## Declaration

This work contains no material which has been accepted for the award of any other degree or diploma in any university or other tertiary institution.

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## Acknowledgements

Firstly, after the bumpy start to my PhD studies, I would like to thank my two supervisors, **Prof. Richard Hillis** and **Dr. Geoff Weir**. Amongst other things, Richard assisted me in setting the foundations to successfully conduct my studies, while Geoff provided excellent and extremely valuable technical knowledge which assisted me greatly, at times under very trying conditions. I would particularly like to thank Geoff and of late Richard for taking time out of their day jobs to supervise my studies and assist me in being able to complete my studies.

I would also like to thank my two previous supervisors, Hemanta Sarma and Seung Ihl Kam for their supervision and guidance during the initial stages of my studies, and for laying the foundations during my undergraduate days. I would particularly like to thank Hemanta Sarma for introducing the idea of furthering my studies with an option to conduct a PhD and assisting in the realisation of this.

I would like to thank the Co-operative Research Centre for Greenhouse Gas Technologies (CO2CRC) for both the financial support they have given me to complete my studies, as well as providing a broad range of experiences and opportunities within and outside of my studies. I would like to thank all my colleagues within the CO2CRC (too many to name) for making my time within the CO2CRC fun, interesting and a very worthwhile experience. In particular I would like to thank Prof. John Kaldi for providing the opportunity to be a part of the CO2CRC and for the guidance and support during my time with the organisation.

I would like to acknowledge Fiona Johnston for providing professional editing services for the preparation of this thesis.

I would like to thank all of the staff and students, both past and present, from the Australian School of Petroleum for providing the necessary support to complete both my undergraduate and now postgraduate studies. Without their expertise and support, my task of completing would have been made considerably harder, if not impossible.

Last but not least, I would like to thank my family and friends. In particular I would like to thank my mum and dad for all of the love, help and support they have given me and for the sacrifices they have made to give me all of the opportunities I have had. I can never repay the debt I owe you but I will give it a go. I would like to thank my brohan, Courtney, for all the help he has given me and for all of the shenanigans we have got up to, and for being considerably shorter than me. I would like to thank the female one, Nina, for all of the love and support she has given me over these long, long 8 years and also to the rest of the Rudduck family for making me feel very welcome. Finally I would like to thank all of my friends, one is not going to name you all as the list would be super massive

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because one is so popular, but without them I would not have received as many scars and injuries as I have through various, at times drunken, escapades and for providing much needed stress relief, andy how.

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## Nomenclature

<u>Symbol</u>	<u>Description</u>
$\phi$	porosity
$\lambda$	mobility of the fluid
$\lambda$	exponent (relative permeability correlation)
$\mu$	viscosity
$\rho$	density
A	area
$B_g$	formation volume factor
$B_{gi}$	initial formation volume factor
$B_{ga}$	formation volume factor at abandonment conditions
C	concentration
C	Land's trapping constant
$c_t$	total aquifer compressibility
D	diffusion coefficient
E	expansion factor
g	gravity constant
G	gas volume initially in place
$G_p$	gas volume produced
h	thickness
k	permeability
$k_r$	relative permeability
$k_{rg}$	gas relative permeability
$k_{rl}$	liquid relative permeability
l	length
M	mobility ratio
n	number of moles
p	pressure
$P_c$	capillary pressure
$P_0$	strength coefficient
q	flow rate
R	universal gas constant
$R^2$	correlation coefficient
$R^2_{\text{adjusted}}$	adjusted correlation coefficient

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$R_{v/g}$	viscous to gravity ratio
sc	standard conditions
$S_g$	gas saturation
$S_{gr}$	residual gas saturation
$S_{gt}$	trapped gas saturation
$S_{lr}$	residual liquid saturation
$S_w$	water saturation
$S_{wi}$	initial water saturation
$S_{wir}$	irreducible water saturation
t	time
T	temperature
u	Darcy velocity
V	volume
W	total water volume
$W_e$	cumulative volume of water influx
x	distance
$x_g$	gas phase concentration
$x_l$	aqueous phase concentration
Z	compressibility factor

<u>Acronyms</u>	<u>Description</u>
ANOVA	ANalysis Of VAriance
CCD	Central Composite Design
CCS	Carbon Capture and Storage
CH <sub>4</sub>	Methane
CO <sub>2</sub>	Carbon dioxide
CO2CRC	Co-operative Research Centre for Greenhouse Gas Technologies
CSEGR	Carbon Sequestration with Enhanced Gas Recovery
ED	Experimental Design
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
GWC	Gas Water Contact
HCPV	Hydrocarbon Pore Volume
MM	Million

---

NPV	Net Present Value
OBPP	Otway Basin Pilot Project
OGIP	Original Gas in Place
PDE	Partial Differential Equations
PVT	Pressure Volume Temperature
RF	Recovery Factor
RMSE	Root Mean Square Error
Scf	Standard Cubic Feet
SGS	Sequential Gaussian Simulation
STB	Stock Tank Barrel