Published by:

IEA Greenhouse Gas R&D Programme
Pure Offices
Cheltenham Office Park
Hatherley Lane
Cheltenham
Gloucestershire
GL51 6SH

Printed by: ----------

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Date Published: 2016
Review compiled and designed by Becky Kemp.

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Background

The IEA Greenhouse Gas R&D Programme (IEAGHG) hold a primary remit to act as an informed source of impartial information on greenhouse gas mitigation options, and this is achieved by the instigation and management of research studies and technological evaluations, and the establishment and maintenance of a growing series of international research networks. The reports from these studies and networks form the core of information available to IEAGHG members on an ongoing basis.

Each technical study will include a short overview prepared by the respective IEAGHG staff member responsible for the management of the study, and each network report incorporates a short executive summary, briefly summising the topics discussed at the meeting, and any significant conclusions or developments.

This book follows up on the success of the fourth Overview Book produced in 2014. It draws together the overviews and executive summaries written by IEAGHG over the course of 2015, segregating the overviews into their respective category, as directed in the contents, in order to allow IEAGHG members and other readers to quickly identify the reports by subject area, or area of interest at a glance.

This book also serves as a quick reference guide for IEAGHG staff and members to quickly and efficiently pick out previous reports that may be useful or relevant to current activities and studies.

IEAGHG Technical Reviews and Information Papers 2015

Technical Reviews

- 2015-TR1 Peer Review (CONFIDENTIAL)
- 2015-TR2 Carbon Storage FY2015 Peer Review
- 2015-TR3 CCS Deployment

Information Papers

- 2015-IP1; GHGT-12 Feedback and Conference Statistics
- 2015-IP2; The Finance Sector needs CCS. So is this a New Source of Funding for Demonstration and Deployment of CCS projects?
- 2015-IP3; U.S. and India Climate and Clean Energy Cooperation
- 2015-IP4; U.S. Actions to Reduce Methane Emissions
- 2015-IP5; The World of Carbon Trading as it Stands Today
- 2015-IP6; Rivers in the Sky? No, it's not Science Fiction
- 2015-IP7; IEA Industry Co-ordination Group Webinar in Waste Heat Recovery
- 2015-IP8; The Case for a Low Carbon Energy Transition in the UK
- 2015-IP9; The Water - Climate Change Nexus
- 2015-IP10; The Earth's Getting Hotter and so does the Scientific Debate
- 2015-IP11; Global Emissions of Carbon Dioxide from the Energy Sector Stalled in 2014
- 2015-IP12; Exploring Methane Emissions with IPIECA
- 2015-IP13; ADEME's CCUS Symposium
- 2015-IP14; Is a Mini Ice Age on the Way that will Stop Global Warming
- 2015-IP15; Rating Country Commitments to COP21
- 2015-IP16; The IEA Position on CCS
- 2015-IP17; First Reports Released from UK FEED on Peterhead and White Rose Projects
- 2015-IP18; Impact of other GHG's and Air pollutants on the 2ºC Carbon Budget

- 2015-IP19; CO_2MultiStore Optimising CO_2 storage around the UK - London launch
- 2015-IP20; Risk Management and Environment Research Combined Meeting
- 2015-IP21; Report on London Convention meeting LC-37 LP-10
- 2015-IP22; Energy Storage
- 2015-IP23; Status Report on Direct Air Capture
- 2015-IP24; INDCs and Implications for CCS
- 2015-IP25; CSLF Ministerial in Riyadh
- 2015-IP26; Extreme Weather and Climate Change – "The proof if proof was needed".
- 2015-IP27; "Pathways to Commercialisation" Event
- 2015-IP28; HFC's included In Montreal Protocol
- 2015-IP29; Emissions Performance Standards - For or Against
- 2015-IP30; Special Issue 10 year Anniversary IPCC
- 2015-IP31; Analysis - the Key Announcements from Day 1 at COP21
- 2015-IP32; COP21 CCS Achievements and Opportunities for Developing Country Involvement
- 2015-IP33; IEA CCS High Level Dialogue (CONFIDENTIAL)
- 2015-IP34; ENGO Support for CCS
- 2015-IP35; 49th Meeting of the Working Party on Fossil Fuels
- 2015-IP36; CSLF Report on Technical Barriers and R&D Opportunities for Offshore, Sub-Seabed Geologic Storage of CO_2
- 2015-IP37; IEA CCS Dialogue - Meeting Summary

2015-05 OXY-COMBUSTION TURBINE POWER PLANTS

Key Messages

- The predicted thermal efficiencies of the oxy-combustion turbine power cycles assessed in this study range from 55% (LHV basis) for the NET Power cycle to around 49% for the other base case cycles. For comparison, a recent IEAGHG study predicted an efficiency of 52% for a natural gas combined cycle plant with post combustion capture using a proprietary solvent.
- There is scope for improving the thermal efficiencies in future, for example by making use of materials capable of withstanding higher temperatures. Proprietary improvements by process developers may also result in higher efficiencies.
- The levelised cost of electricity (LCOE) of base-load plants using natural gas at 8 €/GJ are estimated to be 84-95 €/MWh, including CO_2 transport and storage costs. The lowest cost oxy-combustion plant (NET Power) has a slightly lower LCOE than a conventional gas turbine combined cycle with post combustion capture using a proprietary solvent.
- The cost of CO_2 emission avoidance of the various cycles compared to a reference conventional natural gas combined cycle plant is 68-106 €/t CO_2 avoided.
- The base case percentage capture of CO_2 in this study was set at 90% but it was determined that it could be increased to 98% without increasing the cost per tonne of CO_2 avoided, or essentially 100% if lower purity CO_2 was acceptable.
- The water formed by combustion is condensed in oxy-combustion turbine cycles, which would mean that if air cooling was used the power plants could be net producers of water. This could be an advantage in places where water is scarce, although air cooling would reduce the thermal efficiency.
- Oxy-combustion cycles could have advantages at compact sites. The total area of an oxy-combustion combined cycle plant is estimated to be slightly less than that of a conventional combined cycle with post combustion capture. The ASU could be located off-site if required to further reduce the power plant area. In addition, regenerative oxy-

combustion cycles are significantly more compact than combined cycles.

- Oxy-combustion turbines could be combined with coal gasification. The predicted thermal efficiency of a coal gasification plant with a semi-closed oxy-combustion combined cycle (SCOC-CC) is 34% (LHV basis). This is similar to that of more conventional CCS technologies (IGCC with pre-combustion capture and supercritical pulverised coal with post combustion amine scrubbing) but the estimated capital cost and cost of electricity of the oxy-combustion turbine plant are significantly higher.

Background to the Study

Post combustion capture is usually considered to be the leading option for capture of CO_2 at natural gas fired power plants but there is increasing interest in the alternative of oxy-combustion turbines which use recycled CO_2 and/or H_2O as the working fluid instead of air. Large component tests have taken place and a 50 MWth demonstration plant is scheduled to be commissioned in 2017. Oxy-combustion turbines can also be combined with solid fuel gasification as an alternative to IGCC with pre-combustion capture. This study provides an independent evaluation of the performance and costs of a range of oxy-combustion turbine cycles, mainly for utility scale power generation. The study was carried out by Amec Foster Wheeler in collaboration with Politecnico di Milano.

Scope of Work

The study includes the following:

- A literature review of the most relevant systems featuring oxy-combustion turbine cycles, discussing the state of development of each of the cycles and their components.
- Detailed modelling of the gas turbine for the most promising cycles, including efficiency, stage number and blade cooling requirements. This modelling was carried out using calculation codes developed by Politecnico di Milano for performance prediction of gas turbines.
- Technical and economic modelling of complete oxy-combustion turbine power plants, including sensitivity analyses for a range of technical design and financial parameters.

- Assessment of potential future improvement, including high temperature turbine materials.
- High level evaluation of the most promising niche market applications for oxy-combustion turbines, particularly in smaller power plants.
- An assessment of oxy-combustion turbines combined with coal gasification.

The study has been undertaken in consultation with technology developers but to avoid any possibility of restrictions on dissemination of the results no confidential information has been used.

Study Basis

Technical and Economic Basis

The technical and economic conditions for power plants will depend on many site specific factors. IEAGHG has used, as far as possible, a standard technical and economic basis in its studies of CCS plants to ensure comparability but it is recognised that the absolute values of efficiency, costs etc. will depend on local conditions and assumptions. The technical and economic basis for the study is described in detail in the main study report and the main base case assumptions are as follows:

- Greenfield site, North East coast of the Netherlands
- 9°C ambient temperature
- Natural draught cooling towers
- European pipeline natural gas: 46.5 MJ/kg (LHV), 3% total inerts
- CO_2 to storage: 11MPa, 100ppm O_2, 50ppm H_2O
- 2Q 2014 costs
- Natural gas price: 8 €/GJ LHV basis (equivalent to 7.23 €/GJ HHV basis)
- Coal price: 2.5 €/GJ LHV basis (equivalent to 2.39 €/GJ HHV basis)
- Discount rate: 8% (constant money values)
- Operating life: 25 years
- Construction time – Natural gas fired plants: 3 years
  – Coal gasification plants: 4 years
- Capacity factor – Natural gas fired plants: 90% (65% and 85% in years 1 and 2)
  – Coal gasification plants: 85% (60% and 80% in year 1 and 2)

- CO_2 transport and storage cost: 10 €/t stored

The degree of CO_2 capture was set at approximately 90% but there were slight variations between cases. Sensitivities to higher percentage capture and CO_2 purity levels were also assessed.

The reference power plant without CO_2 capture in this study was based on two state-of-the-art 50Hz F class gas turbines, resulting in a net power output of 904 MW. The oxy-combustion turbine plants were designed to have the same fuel feed rates as the reference plant without capture, resulting in net power outputs in the range of 660-850 MW.

Cost Definitions

Capital Cost

The cost estimates were derived in general accordance with the White Paper "Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants", produced collaboratively by authors from IEAGHG, EPRI, USDOE/NETL, Carnegie Mellon University, IEA, the Global CCS Institute and Vattenfall[1].

The capital cost is presented as the Total Plant Cost (TPC) and the Total Capital Requirement (TCR). TPC is defined as the installed cost of the plant, including project contingency. In the report TPC is broken down into:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency

TCR is defined as the sum of:

- Total plant cost (TPC)
- Interest during construction
- Owner's costs
- Spare parts cost

[1] Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants, IEAGHG Technical Review 2013/TR2, March 2013.

- Working capital
- Start-up costs

For each of the cases the TPC has been determined through a combination of licensor/vendor quotes, the use of Foster Wheeler's in-house database and the development of conceptual estimating models, based on the specific characteristics, materials and design conditions of each item of equipment in the plant. The other components of the TCR have been estimated mainly as percentages of other cost estimates in the plant.

Estimation of costs of technologies that are at relatively low technology readiness levels (TRL) is inevitably subject to significant uncertainty and involves a balance of judgement which is provided in this study by an experienced process engineering contractor. The oxy-combustion turbine power plants include novel equipment that are either under development or at a conceptual stage only and overall integrated plants have not yet been operated. This study has investigated the potential of the oxy-combustion turbine plants with respect to benchmark technologies for capture of CO_2 that are generally assumed to be ready for commercial application. The study has therefore treated the oxy-combustion turbine plants as Nth-of-a-kind (NOAK) plants for estimating purposes. The cost of novel equipment has been evaluated as already developed and suitable for large-scale commercial application and no additional contingencies have been applied. Nevertheless, the sensitivity to the cost of the novel equipment has been assessed to take into account to a certain extent the intrinsic uncertainty of such estimates.

It is recognised that by the time the oxy-combustion turbine processes actually reach NOAK plant status there will have been further improvements in their technology but the technology of air blown gas turbines is also expected to continue to improve over this time scale. Prediction of future improvements in the technologies of air and oxy-combustion turbines would have involve excessive speculation and has therefore been avoided in this study.

Levelised Cost of Electricity

Levelised Cost of Electricity (LCOE) is defined as the price of electricity which enables the present value from all sales of electricity over the economic lifetime of the plant to equal the present value of all costs of building, maintaining

and operating the plant over its lifetime. LCOE in this study was calculated assuming constant (in real terms) prices for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from lower capacity factors in the first two years of operation. It should be noted that base-load LCOE is not a complete measure of the relative economic merits of different types of power plant. The ability to operate flexibly and to provide ancillary services to the electricity system can provide significant additional income but this is beyond the scope of this study.

Cost of CO_2 Avoidance

Costs of CO_2 avoidance were calculated by comparing the CO_2 emissions per kWh and the levelised costs of electricity of plants with capture and a reference plant without capture.

$$CO_2 \text{ avoidance cost (CAC)} = \frac{LCOE_{ccs} - LCOE_{Reference}}{CO_2\ Emission_{Reference} - CO_2\ Emission_{ccs}}$$

Where:
CAC is expressed in Euro per tonne of CO_2
LCOE is expressed in Euro per MWh
CO_2 emission is expressed in tonnes of CO_2 per MWh

For calculation of the CO_2 avoidance cost, the reference plants in this study were assumed to be plants without CCS that use the same type of fuel as the oxy-combustion turbine plants and the type of technology that is most likely to be preferred for that type of fuel. Hence the reference plant for natural gas fired oxy-combustion turbine plants is a conventional natural gas combined cycle (NGCC) plant and the reference plant for the coal gasification oxy-combustion turbine plant is a supercritical pulverised coal (SC-PC) plant without CCS. It is assumed that for coal-fired plants without CO_2 capture a SC-PC plant would be preferred to an IGCC plant because of lower expected costs.

Findings of the Study

Literature Review and Cycle Selection

A literature review was carried out to identify the leading natural gas fired oxy-combustion turbine cycles. The cycles were ranked on the basis of their expected efficiencies and the technological development still required for their key components. The following four cycles were selected for more detailed technical and economic assessment:

- Semi-closed oxy-combustion combined cycle (SCOC-CC)
- NET power cycle
- S-Graz cycle
- CES cycle

In the first two of these cycles the working fluid is mainly CO_2 and in the final two it is mainly H_2O.

Semi-Closed Oxy-Combustion Combined Cycle (SCOC-CC)

The SCOC-CC resembles a conventional combined cycle, except that inlet gas to the turbine compressor is mainly recycled CO_2–rich gas rather than air from the atmosphere, and oxygen from an air separation unit (ASU) is fed to the combustor. The exhaust gas from the turbine passes through a heat recovery steam generator (HRSG) which generates steam for a steam cycle, as in a conventional combined cycle. Instead of being vented to the atmosphere the cooled gas from the HRSG is further cooled, which condenses most of the water produced by combustion. Most of the cooled CO_2-rich gas is then recycled to the gas turbine compressor and the rest is compressed and purified for CO_2 storage. The SCOC-CC has been proposed and studied by various organisations. Although it resembles a conventional combined cycle it would not be possible to retrofit a conventional gas turbine as an oxy-combustion turbine because of the substantially different physical properties of CO_2 compared to air.

NET Power

The NET Power cycle utilises CO_2 as the working fluid in a high pressure, low pressure ratio recuperated Brayton cycle with an inlet pressure of around 300 bar and a pressure ratio of around 8-12. Oxygen and natural gas are fed to the high pressure combustor. A recuperative heat exchanger is used to

transfer heat from the turbine exhaust gas to high pressure CO_2-rich recycle gas. Recompression of the recycle gas takes place firstly in a gas compressor and finally in a liquid pump. NET Power and 8 Rivers Capital, together with Toshiba, CB&I and Exelon are developing this cycle and a 50MWth plant in Texas is scheduled to start commissioning in 2016.

Modified S-Graz Cycle

Different variants of the S-Graz cycle have been proposed and two have been evaluated in this study. The working fluid in the Modified S-Graz cycle is mainly steam, along with some recycled CO_2. The cycle includes a high temperature gas turbine with an inlet pressure of about 45 bar followed by an HRSG. High pressure steam generated in the HRSG is fed to a steam turbine which exhausts into the gas turbine combustor and turbine. Some of the outlet gas from the HRSG is recompressed and sent to the turbine combustor and the remainder is compressed and cooled, thereby condensing the steam it contains, leaving a CO_2-rich gas to be fed to storage. Heat from cooling and condensation of the compressed gas is used to generate low pressure steam which is fed to a separate steam turbine. The S-Graz cycle is being researched primarily at the University of Graz, Austria.

CES Cycle

The cycles being developed by Clean Energy Systems (CES) use water, both in vapour and liquid phases, as the combustor temperature moderator. Different versions of the CES cycle have been proposed and three versions representing near to longer term variants were evaluated in this study. The results presented in this overview are for a new supercritical pressure cycle as proposed by CES during this study. The cycle includes a high pressure oxy-fuel combustor where part of the fuel and oxygen are combusted using steam in supercritical conditions as the temperature moderator, while hot gas produced in the gas generator is expanded in a steam cooled HP turbine. The high pressure turbine exhaust gas is double reheated by supplementary oxy-fuel combustion and further expanded in medium and low pressure sections of the gas turbine, down to vacuum conditions. CES has been working with partners on development of pressurised oxy-combustion power systems for more than 15 years. The primary focus of this development work has been on the new or novel components of the cycle, including high pressure

combustors, reheaters and turbines. Oxy-fuel gas generators of up to 170 MWth and reheat combustors up to 28 MWth have been operated at a test facility in California and hot gas has been fed to modified gas turbines.

Performance of Natural Gas-Fired Oxy-Combustion Power Plants

A summary of the performance of the base case natural gas-fired oxy-combustion turbine power plants and the reference plant is given in Table 1. The plants all have the same natural gas feed rate of 1536 MW (LHV).

The highest efficiency of 55% is for the NET Power cycle, the other three oxy-combustion processes have lower efficiencies of around 49%. The developers of the NET Power cycle have estimated an efficiency of 59% for their cycle using proprietary improvements and CES has estimated an efficiency of 53% for its cycle. The supercritical version of the CES cycle is a relatively recent innovation. Adopting a lower coolant temperature would be likely more advantageous and is currently being pursued by CES as part of their on-going cycle optimization work.

The power consumption of the air separation unit (ASU) including oxygen compression is substantial in all of the oxy-turbine cycles, being equivalent to 10-11% points of overall thermal efficiency.

	Net Power Output	CO_2 Captured	CO_2 Emissions	Efficiency		Efficiency Penalty for Capture (LHV)
	MW	kg/MWh	kg/MWh	LHV	HHV	% points
				%	%	
Reference NGCC plant	904	-	348	58.8	53.2	
SCOC-CC	757	377	39	49.3	44.6	9.5
NET Power	846	336	37	55.1	49.9	3.7
Modified S-Graz	756	375	41	49.2	44.6	9.6
CES	751	379	41	48.9	44.3	9.9

Table 1, Performance of Natural Gas-Fired Power Plants

Costs of Natural Gas Fired Oxy-Combustion Power Plants

Capital costs, levelised costs of electricity and costs of CO_2 avoidance are summarised in Table 2 (see next page). The NET Power process has the lowest costs while the costs of the three other processes are broadly similar. Breakdowns of the Total Plant Costs are shown in Figure 1 (see overleaf).

	Total Plant Cost (TPC)		Total Capital Requirement (TCR	Levelised Cost of Electricity (LCOE)		CO_2 Avoidance Cost
	€/kW	% increase for capture		€/MWh	% increase for capture	€/tonne
Reference NGCC	655	-	855	62.5	-	-
SCOC-CC	1470	124	1905	92.8	48	98
NET Power	1320	102	1715	83.6	34	68
Modified S-Graz	1500	129	1955	93.7	50	101
Revised CES	1540	135	2000	95.1	52	106

Table 2, Costs of Natural Gas Fired Plants

It can be seen from Figure 1 (overleaf) that the main reason for the higher capital costs of the oxy-combustion turbine plants compared to the reference plant is the cost of the ASU (including oxygen compression), followed by the CO_2 compression and purification unit (CPU) and the balance of plant items.

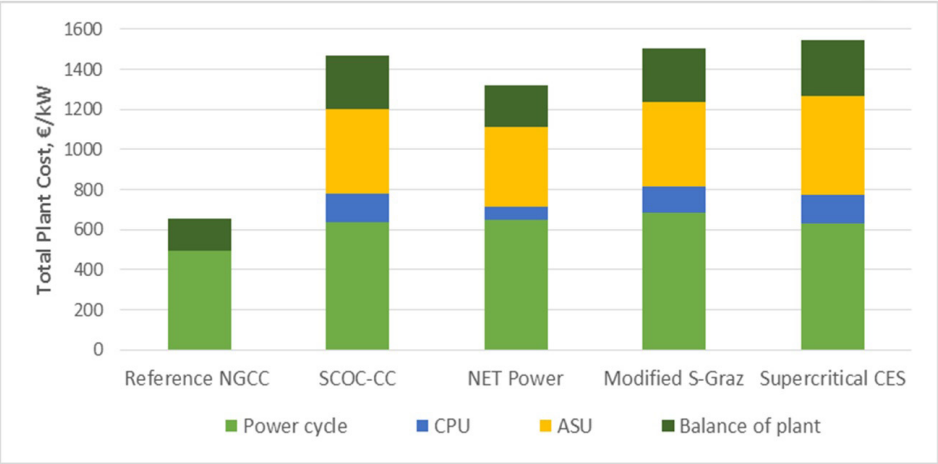

Figure 1, Specific Total Plant Costs – Natural Gas Fired Plants (2Q2014)

A breakdown of the levelised costs of electricity (LCOE) is shown in Figure 2. The main contribution to the LCOE in all cases is the fuel cost, which depends

on the thermal efficiency, but the main contribution to the additional cost of capture is the additional capital cost.

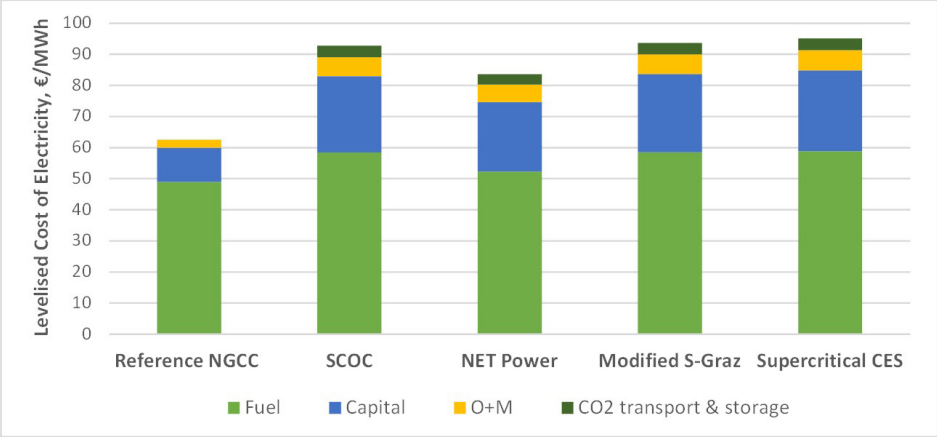

Figure 2, Levelised Costs of Electricity

Comparison of Oxy-Combustion and Post Combustion Capture Plants

In 2012 IEAGHG published a study on natural gas combined cycle plants with post combustion capture[2]. The study assessed plants using MEA scrubbing with and without gas turbine flue gas recycle and a plant using a proprietary capture solvent. A comparison of the efficiency and costs of the most favourable case evaluated in that study, i.e. the proprietary solvent case, and the two oxy-combustion cases from this study with the highest efficiencies and lowest costs (SCOC-CC and NET Power) are shown in Table 3.

	Efficiency (LHV)	Total Plant Cost	Levelised Cost of Electricity	CO_2 Avoidance Cost
	%	€/kW	€/MWh	€/tonne
Reference NGCC	58.8	655	62.5	-
SCOC-CC	49.3	1470	92.8	98
NET Power	55.1	1320	83.6	68
NGCC post combustion capture	52.0	1170	84.7	72

Table 3, Comparison of Oxy-Combustion and Post Combustion Capture Plants

[2] CO_2 capture at gas fired power plants, IEAGHG report 2012/8, July 2012.

The SCOC-CC plant has a lower thermal efficiency than the plant with post combustion capture but the efficiency of the NET Power case is significantly higher. The Total Plant Costs of the oxy-combustion plants are higher than that of the post combustion capture plant.

The NET Power plant has a lower LCOE and cost of CO_2 avoidance than the post combustion capture plant because the higher efficiency and hence lower fuel cost more than offsets the higher capital cost. In contrast the LCOE and CAC of the SCOC-CC (and the other oxy-combustion plants evaluated in this study) are higher than those of the post combustion capture plant.

The capital costs in IEAGHG's post combustion capture study were on a 2011 basis but there is reported to have been no significant change in the costs of European power plants in general between 2011 and 2014 (i.e. the cost estimation date of this oxy-combustion study)[3]. This oxy-combustion study used some updated assumptions compared to the post combustion capture study, particularly regarding natural gas price and CO_2 transport and storage costs. The LCOE and CAC for post combustion capture shown in Table 3 were recalculated from the 2011 study using the updated assumptions.

The plants in this study were based on natural draught cooling towers, in common with IEAGHG's recent study on coal fired plants but the earlier study on natural gas post combustion plants[4] was based on mechanical draught cooling towers. As described later, a NET Power plant using mechanical draught cooling towers was assessed as a sensitivity case. The TPC of that plant was 1245 €//kW, i.e. closer to that of the post combustion capture plant and the LCOE was slightly lower at 82 €/MWh. The efficiency of the NET Power process estimated in this study was lower than NET Power's own estimate of 58.8%. Increasing the efficiency to 58.8% would reduce the LCOE by 3 €/MWh due to lower fuel costs, or 5 €/MWh if there was also a corresponding reduction in the capital cost per kW. NET Power provided their own commentary on the differences between their efficiency and cost estimates and those presented in this study and this is included in the detailed study report.

[3] IHS European Power Capital Cost Index (EPCCI), excluding nuclear, **www.ihs.com/Info/cera/ihsindexes/index.html**

[4] CO_2 capture at coal-based power and hydrogen plants, IEAGHG report 2014-3, May 2014.

Sensitivity to Technical Parameters

Sensitivities to the following technical parameters were assessed. The sensitivities were only evaluated for selected cycles to avoid an excessive number of cases.

- Turbine combustor outlet temperature
- Turbine maximum metal temperature
- CO_2 purity requirements
- Percentage capture of CO_2
- Oxygen purity in the range of 95-99.5%
- Natural gas with a high CO_2 concentration: 70% (vol.)
- Natural gas with a high N_2 concentration: 14% (vol.)
- Higher ambient temperature: 25°C
- Alternative cooling system: mechanical draught cooling towers

Potential Future improvements: Turbine Temperatures

The thermal efficiencies of conventional NGCCs are expected to improve in future due to various technological improvements, in particular higher firing temperatures which increase the thermodynamic cycle efficiency, and higher allowable material temperatures which reduce the turbine cooling gas requirement. It is important to assess whether the oxy-combustion turbine cycles would also be able to take advantage of such future technological advances to remain competitive. Increasing the combustor outlet temperature by 80°C (SCOC-CC) and 50°C (NET Power), and increasing the allowable turbine material temperature by 90°C increased the efficiencies of the NET Power and SCOC-CC cycles by 1.6 and 0.5 percentage points respectively. Simply increasing the combustor outlet temperature without also increasing the metal temperature produced almost no improvement in the efficiency.

Percentage Capture and CO_2 Purity

CO_2 purity specifications for CCS are not yet clearly defined and they may vary between different applications, e.g. EOR and saline reservoir storage. In this study the CO_2 for storage is specified to have a conservative oxygen concentration of 100ppmv. This is achieved using a low temperature CO_2 purification unit which removes O_2 and also other impurities, mainly N_2 and

Ar, resulting in an overall CO_2 purity of 99.6–99.8%. The vent gas stream of impurities also includes some CO_2, resulting in incomplete CO_2 capture. The base case plants in this study were designed to achieve 90% CO_2 capture, in common with IEAGHG's other techno-economic studies on CO_2 capture, but higher percentage capture could be achieved if required. If lower purity CO_2 were acceptable the CO_2 purification unit could be removed, in which case essentially 100% of the CO_2 would be captured. Alternatively if a high purity CO_2 product were required the vent gas from the low temperature purification unit could be processed, for example in a membrane unit. A substantial portion of the CO_2 would be recovered, resulting in around 98% overall CO_2 capture. These schemes for high percentage capture were assessed for the NET Power cycle and the results are summarised in Table 4.

CO_2 Capture	CO_2 Purity	Efficiency	TPC	LCOE	CAC
%	%	%	€/kW	€/MWh	€/t
90	99.8	55.1	1320	83.6	68
98	99.8	54.7	1340	84.8	65
100	97.9	55.3	1270	82.7	58

Table 4, Sensitivity to Percentage Capture and CO_2 Purity

Oxygen Purity

Nitrogen and argon enter the cycles in the natural gas and oxygen streams. These gases increase the duty of the CO_2 product compression and purification units and they can also increase the energy required for CO_2 re-pressurisation in very high pressure cycles such as the NET Power cycle in which the CO_2 forms a liquid during re-pressurisation. These disadvantages can be reduced by producing higher purity oxygen but this increases the power consumption and cost of the air separation unit (ASU). Sensitivity cases indicated that the oxygen purities selected for the study, i.e. 99.5% for the NET Power cycle and 97% for the other cycles are close to the optimum.

High-N_2 Natural Gas

Some sources of natural gas include significant concentrations of N_2. The effects on the cycles are similar to those of using lower purity oxygen. Using natural gas with 14% vol. N_2 instead of the base case of 0.9% reduced the efficiency of the S-Graz cycle by 0.2%.

High-CO_2 Natural Gas

Natural gas from some fields has a high CO_2 concentration. Oxy-combustion turbines may be an attractive option for use of such gas, when CO_2 abatement is required. If the quantity of CO_2 entering the cycle with the natural gas increases, the quantity of CO_2 or H_2O recycled to the turbine is correspondingly reduced, with little overall impact on the power generation cycle. The main impact is an increase in the throughput and power consumption of the CO_2 product compression and purification unit. Use of natural gas with 70% CO_2 in a Modified S-Graz cycle resulted in a 5.5% point reduction in efficiency and a 20% increase in the capital cost per kW of net output. In contrast, because the quantity of CO_2 captured is about 3 times higher than in the base case, the cost per tonne of CO_2 avoided is substantially lower.

Ambient Conditions

The efficiencies of power cycles in general decrease when the ambient temperature increases. This is in line with the fundamental thermodynamic principle that the efficiency depends on the difference between the upper and lower absolute temperatures of the cycle. Increasing the ambient air temperature from 9 to 25°C reduces the efficiencies of the Modified S-Graz and SCOC-CC cycles by 2.4-2.7 percentage points.

Alternative Cooling Water System

The base case cooling water system for this study was assumed to be natural draught cooling towers, in common with IEAGHG's recent study on coal fired plants with CCS. The other common choice for natural gas power plants is mechanical draught cooling towers. A sensitivity case of the NET Power cycle was assessed in which natural draught towers with an approach of 7°C were replaced by mechanical draught cooling towers with an aggressive approach of 4°C. Using mechanical draught cooling towers increased the thermal efficiency from 55.1% to 55.4%, because the power requirement for cooling tower fans was more than offset by reductions in the compression power requirements, mainly the recycle gas compression, as well as small reductions in the ASU and the final CO_2 compression and purification unit. The Total Plant Cost reduced from 1320 to 1245 €/kW, the LCOE reduced from 83.6 to 81.7 €/MWh and the CO_2 avoidance cost reduced from 67.6 to 61.5 €/t CO_2.

The availability of water for cooling is an important constraint at some power plant locations. The water requirement for the cooling system could be avoided by using dry air coolers but this would reduce the overall plant efficiency. The use of air cooling was not assessed in this study but it could be assessed in future. The impacts of air cooling will depend on the ambient conditions, the type of power generation cycle and the cooling system design specifications, so it is recommended that several cases should be assessed as part of an overall study on the impacts of water availability on CCS plants. Because almost all of the water produced by combustion of natural gas is condensed in oxy-combustion turbine plants, use of air cooling would make the plants net producers of water.

Economic Sensitivities

There is significant uncertainty in the estimated costs of innovative equipment used in the oxy-combustion cycles. The proportion of innovative equipment, mainly gas turbines and high temperature/high pressure heat exchangers, is different in the different cycles. The sensitivity of LCOE to variations in the costs of innovative equipment is shown in Figure 3.

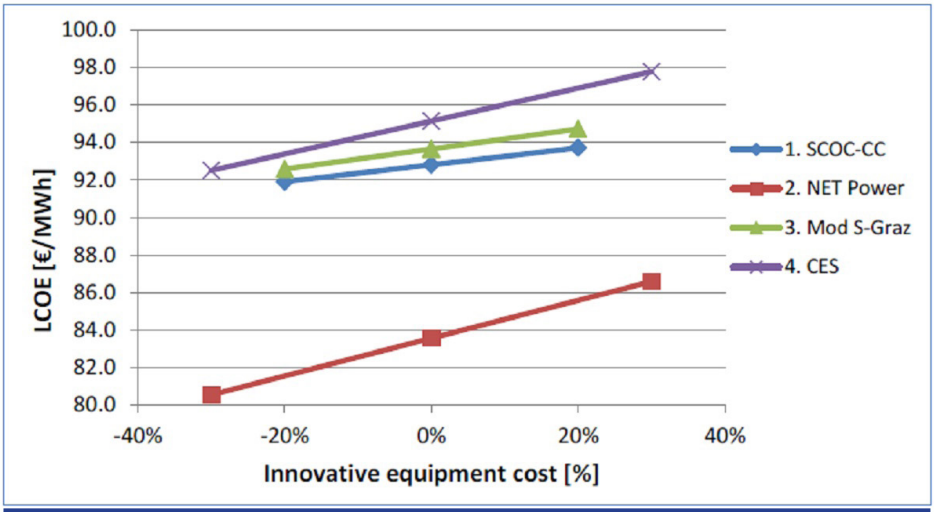

Figure 3, Sensitivity of LCOE to Costs of Novel Equipment

The costs of CCS also depend on economic parameters that will vary over time and between different plant locations. The sensitivities of LCOE and

CAC to the natural gas price, economic discount rate, plant life, cost of CO_2 transport and storage, operating capacity factor and the cost penalty for non-captured CO_2 emissions were evaluated for all of the cycles and the results are presented in the main report. As an example the results for the NET Power cycle are shown in Figures 4 and 5, in which the green bars represent increases from the base case and the red bars are reductions.

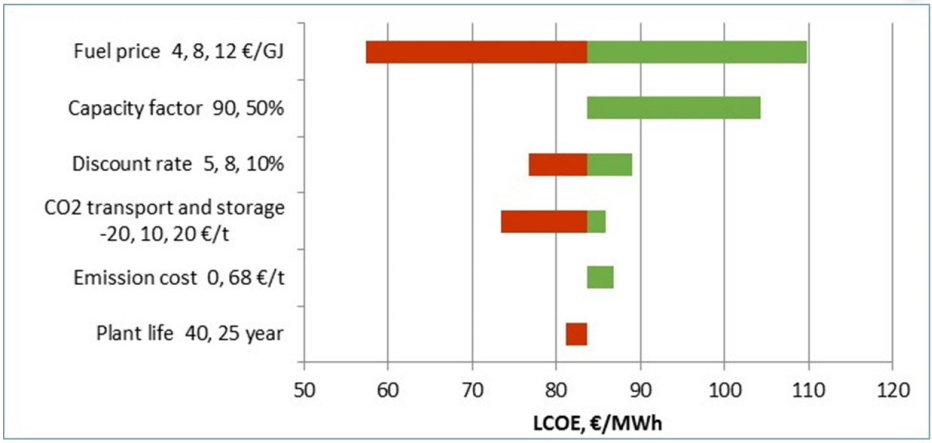

Figure 4, Sensitivity of Levelised Cost of Electricity

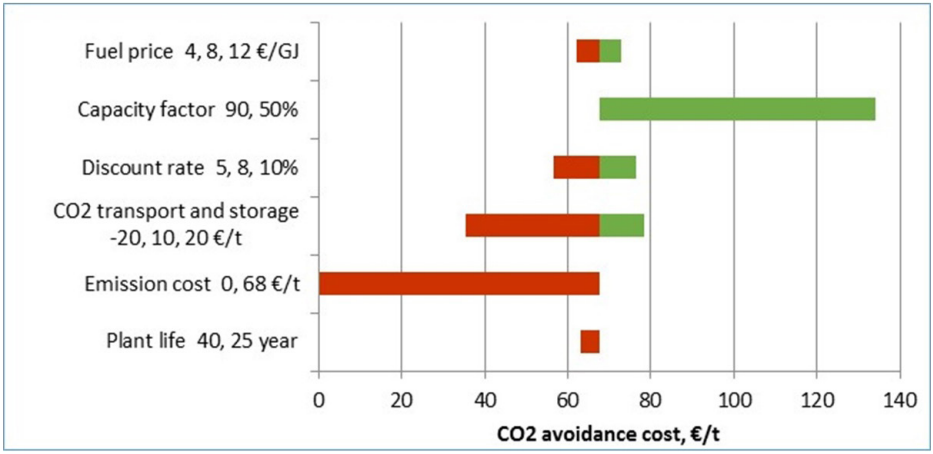

Figure 5, Sensitivity of CO_2 Avoidance Cost

The greatest sensitivity of LCOE is to the natural gas price. Gas prices vary substantially and in many parts of the world are now substantially lower than the €8/GJ base case price used in this study, for example due to the recent drop in global energy prices in general and high availability of shale gas. Reducing the annual capacity factor to 50% results in a substantial increase in the LCOE but if this is because the plant is only operated at times of relatively high power prices and is shut down when the power price is lower than the marginal operating cost, the overall economic viability of the plant may not necessarily be adversely affected. The next most significant sensitivity is to the economic discount rate. Doubling the CO_2 transport and storage cost to 20 €/t CO_2 stored has a relatively small impact on the LCOE but if CO_2 could be sold for EOR for 20 €/t for example, there would be a significant reduction in the LCOE. In this study there was assumed to be no cost associated with emissions of non-captured CO_2. A carbon tax of €68/t CO_2, equivalent to the base case cost of CO_2 avoidance of the NET Power plant, would result in only a small increase in the LCOE. Increasing the operating lifetime of the plant from 25 to 40 years would have only a small impact on the LCOE, because of the effects of economic discounting.

The impacts of the economic parameters on CO_2 avoidance cost are substantially different to their impacts on LCOE. The avoidance cost is a function of the difference between the cost of the oxy-combustion turbine plant and the reference plant. Fuel price has only a small impact because it depends only on the relatively small difference between the efficiencies of the reference plant and the oxy-combustion turbine plant. Reducing the capacity factor has a much larger impact because the capital costs of oxy-combustion turbine plants are much higher than the cost of the reference plant, as shown in Table 2. CO_2 transport and storage cost has a much larger impact on the CO_2 avoidance cost than LCOE because it has no impact on the cost of the reference plant. In contrast, increasing the emission cost increases the cost of the reference plant but has only a small impact on the oxy-combustion plant.

Coal Gasification Plants

All of the oxy-combustion cycles assessed in this study could in principle be combined with coal gasification plants, as an alternative to IGCC with pre-combustion capture. In this study a plant involving coal gasification and

a SCOC-CC was assessed. The plant uses the GE slurry feed, oxygen blown radiant/quench gasification process with fuel gas desulphurisation using the Selexol solvent scrubbing process. The inclusion of fuel gas desulphurisation is a conservative design assumption. It may be possible instead to remove sulphur compounds from the turbine exhaust gas, which may increase the thermal efficiency and reduce costs but it would also increase the risk of corrosion.

The performance and costs of a coal gasification SCOC-CC plant are summarised in Tables 5 and 6, Data for a reference Supercritical Pulverised Coal (SC-PC) plant without capture, a SCPC plant with post combustion capture using a proprietary solvent, a SC-PC oxy-combustion plant and an Integrated Gasification Combined Cycle (IGCC) plant with pre-combustion capture are also provided from a recent IEAGHG study carried out on the same basis by the same contractor. The costs in that study are on a 2Q 2013 basis but there has been no significant change in costs of power plants in Europe between then and the costing date of this study (2Q 2014). The efficiency of the gasification SCOC-CC plant is broadly similar to the efficiencies of the other coal CCS technologies. However, the costs of the gasification SCOC-CC plant are higher than those of the other technologies, particularly the SC-PC plants.

	Net Power Output	CO_2 Captured	CO_2 Emissions	Efficiency		Efficiency Penalty for capture (LHV)
				HHV	LHV	
	MW	kg/MWh	kg/MWh	%	%	% points
Reference SC-PC	1030	-	746	42.2	44.1	-
SC-PC post combustion	822	840	93	33.6	35.2	8.9
SC-PC oxy-combustion	833	823	92	34.1	35.7	8.4
Conventional IGCC	874	844	94	33.3	34.9	9.2
Gasification SCOC-CC	740	876	94	32.5	34.0	10.1

Table 5, Performance of Coal-Fired Plants

	Total Plant Cost (TPC)	Total Capital Requirement (TCR)		Levelised Cost of Electricity (LCOE)		CO_2 avoidance cost (CAC)
	€/kW	€/kW	%	€/MWh	% increase	€/tonne
Reference SC-PC	1450	1890	-	52	-	-
SC-PC post combustion	2770	3600	91	95	82	65
SC-PC oxy-combustion	2760	3580	91	92	76	61
Conventional IGCC	3080	4240	124	114	120	96
Gasification SCOC-CC	3580	4920	160	128	146	116

Table 6, Costs of coal fired plants

Operating Flexibility

Power plants must face the challenges of liberalised electricity markets with variable electricity demands and high amounts of variable renewable electricity generation. Plants have to be able to operate flexibly and this is particularly so for gas fired power plants which have relatively high variable costs of operation (although relatively low fixed costs).

Due to the early status of technology development, specific information on the operating flexibility of oxy-combustion turbine plants is not yet in the public domain. The main limitation on the start-up time and ramp rate may be the ASU. Temporary storage of oxygen could overcome these constraints and also enable the throughput of the ASU to be reduced to provide increased net generation at times of peak electricity demand.

Plant Area

Plant area is important in some cases, for example for retrofits to existing compact sites and application in industrial sites. For combined cycles such as the SCOC-CC and S-Graz cycles the only potential advantage in terms of space requirement is the lower plot area of the ASU and CPU compared to a post combustion capture unit. On the other hand, the potential for space saving is significant for a regenerative cycle such as NET Power. NET Power claims a footprint about a third that of a combined cycle with a similar output. The main limitation to the use of oxy-combustion turbines in compact plants is the space required for the ASU, which alone accounts for around 25%

additional space with respect to a conventional combined cycle. A possible way to overcome this constraint would be to supply oxygen by pipeline from an off-site ASU.

Expert Review Comments

Comments on the draft report were received from reviewers at academic and industrial organisations involved in R&D on oxy-combustion turbine cycles and power generation and CCS in general. The contribution of the reviewers is gratefully acknowledged.

The reviewers' comments were mostly detailed and helpful suggestions to improve the clarity of the presentation and some questions regarding the design bases and differences between the cycle performance predictions in this study and other specific publications. The contractor provided IEAGHG with detailed responses which adequately addressed all of the comments and they made appropriate modifications to the report.

The two industrial cycle developers, namely CES and NET Power, continued to provide helpful information and comments after the draft report was issued. CES proposed an additional variant of their cycle based on a high pressure/high temperature supercritical turbine, to complement their base cases, which use a more conservative near-term design. IEAGHG decided that assessment of this cycle would be a worthwhile addition to the study. NET Power requested that IEAGHG include an additional case that uses mechanical draught cooling towers instead of natural draught cooling towers, which corresponds to the design and costing basis they have used internally. An extra sensitivity case was included in the study to address this suggestion. NET Power provided a helpful commentary on the differences between their own performance and cost assessments and those of Amec Foster Wheeler, and this was included in the study report.

Conclusions

- The predicted thermal efficiencies of the cycles assessed in this study range from 55% (LHV basis) for the NET Power cycle to around 49% for the other base case cycles. For comparison, a recent IEAGHG study predicted an efficiency of 52% for a natural gas combined cycle plant with post combustion capture using a proprietary solvent.

- There is scope for improving the thermal efficiencies in future for example by making use of materials capable of withstanding higher temperatures. Proprietary improvements by process developers may also result in higher efficiencies.
- The levelised cost of electricity (LCOE) of base-load plants using natural gas at 8 €/GJ are estimated to be 84-95 €/MWh, including CO_2 transport and storage costs. The lowest cost oxy-combustion plant (NET Power) has a slightly lower LCOE than a conventional gas turbine combined cycle with post combustion capture using a proprietary solvent.
- The cost of CO_2 emission avoidance of the various cycles compared to a reference conventional natural gas combined cycle plant is 68-106 €/t CO_2 avoided.
- The base case percentage capture of CO_2 in this study was set at 90% but it was determined that it could be increased to 98% without increasing the cost per tonne of CO_2 avoided, or essentially 100% if lower purity CO_2 was acceptable.
- The water formed by combustion is condensed in oxy-combustion turbine cycles which would mean that if air cooling was used, the power plants could be net producers of water, which could be an advantage in places where water is scarce, although air cooling would reduce the thermal efficiency.
- Oxy-combustion cycles could have advantages at compact sites. The total area of an oxy-combustion combined cycle plant is estimated to be slightly less than that of a conventional combined cycle with post combustion capture. The ASU could be located off-site if required to further reduce the power plant area. In addition, regenerative oxy-combustion cycles are significantly more compact than combined cycles.
- Oxy-combustion turbines could be combined with coal gasification. The predicted thermal efficiency of a coal gasification plant with a SCOC-CC is 34% (LHV basis). This is similar to that of more conventional CCS technologies (IGCC with pre-combustion capture and supercritical pulverised coal with post combustion amine scrubbing) but the estimated capital cost and cost of electricity of the oxy-combustion turbine plant are significantly higher.

Recommendations

- IEAGHG should continue to monitor the development of oxy-combustion turbines and report on significant developments.
- As oxy-combustion turbine cycles continue to evolve, a follow-on study could be carried out in future to assess sensitivities of performance and costs to further variations of cycle configuration, operating conditions, heat integration etc. Industrial applications could also be assessed in more detail if required. Further evaluation of operating flexibility should be carried out when sufficient data become available in the public domain.
- IEAGHG should carry out similar techno-economic studies on other emerging capture technologies when sufficient input data become available.

2015-06 INTEGRATED CARBON CAPTURE AND STORAGE PROJECT AT SASKPOWER'S BOUNDARY DAM POWER STATION

Executive Summary

On October 2nd, 2014, the first-ever, commercial–scale, coal-fired power plant incorporating amine solvent absorption carbon capture began operation near Estevan, Saskatchewan, Canada. This was a global landmark event. Although carbon capture technologies had been pilot tested prior to this, a commercial–scale power plant now exists that has demonstrated a number of high-risk technology and business issues have been overcome. This report summarizes the experience and learnings of SaskPower in a way that will hopefully provide insight to other clean-coal initiatives.

For Saskpower, owner and operator of the retrofitted Boundary Dam Power Unit 3 (BD3) that now incorporates carbon capture and storage (CCS), this event was the culmination of decades of work to continue operating coal-fired power-generating stations, while at the same time mitigating the climate change impact of associated air emissions. The CO_2 captured at BD3 is geologically stored at two locations: in an oil reservoir approximately 1.4 kilometres deep at Cenovus' CO_2–EOR operation near Weyburn, Saskatchewan, and in a deep saline aquifer approximately 3.2 kilometres deep at the SaskPower Carbon Storage and Research Centre, located near the Boundary Dam Power Station. The latter geological storage site is the subject of the measurement, monitoring and verification (MMV) activities of the Aquistore Project that is managed by the Petroleum Technology Research Centre in Regina, Saskatchewan.

SaskPower had forged ahead with design and construction of the BD3 ICCS retrofit well in advance of GHG Regulations being enacted in Canada, which came into effect on July 1st, 2015. This was a strategic and environmentally-responsible decision to ensure continued use of lignite coal reserves in Saskatchewan that could last 250–500 years. The investment in the approx. 120 MW (net) BD3 power unit's retrofit and carbon capture plant was approximately C$1.467 billion.

This report explores the journey that SaskPower made from the 1980s to mid-2015 in pursuit of clean-coal power generation. SaskPower pursued various technology options for carbon capture from oxyfuel combustion to

amine solvent absorption that ultimately led to the decision to select the commercially unproven CANSOLV amine solvent carbon dioxide capture process. SaskPower then coupled that technology with Shell Cansolv's proven sulphur dioxide capture process to simplify the capture plant operation and to further reduce emissions.

Two key factors contributed to the decision to retrofit BD3 to convert it to clean coal power:

1. The ability to continue to realize value from the sunk investment in the original 1970 BD3 power unit by retrofitting it with a modern boiler and turbine, rather than building a new power plant; and
2. The value that would be realized over the next 30 years of operating the retrofitted power plant from the sale of three valuable by-products: carbon dioxide, sulphuric acid and fly ash. This would help to offset the cost of capture.

The latter two by-products provide the off-taker market with essential materials for the production of fertilizer and cement, respectively. The captured CO_2 is geologically stored, as noted above, with an associated revenue stream from sale of a portion to oil producers deploying CO_2–EOR.

Construction challenges that were faced by SaskPower are explored in the report. These included:

- complicated contracting issues by using multiple vendors;
- management of a retrofitting project at a "brown-field" site;
- orchestration of the complexities of integrating the power plant with the capture plant;
- safety, risk and permitting management and;
- transition to operations.

One of the most important recommendations for future retrofitting construction projects of this nature is to modularize the design to make the construction simpler and more cost-effective to implement.

Given SaskPower's status as a public power utility, it was critically important to ensure full engagement by its stakeholders in government and the public. SaskPower made dozens of presentations around the province to inform the

public and address questions and concerns. Its design team ensured that technology options were kept open and available to enable key decision makers to build confidence in their technology choices so they could see their way to approving both the power unit's retrofit and the capture plant construction. SaskPower continues to engage its stakeholders in effective and meaningful discussion about BD3 and consideration of future power-generating options.

A summary of challenges that SaskPower faced from inception to operation of the BD3 ICCS project is presented.

Key Challenges Included:

- Choosing a CO_2 capture technology when no commercially–proven technology existed, and managing first-time operation of unfamiliar capture processes and equipment
- Proceeding with a high, targeted CO_2 capture level (90%) and the associated design and construction in the absence of any guidance from GHG regulation that had yet to be enacted
- Managing continual changes in design, equipment, and construction plans throughout the project due to a variety of technology, procurement and corporate policy requirements
- Technology risk and managing the costs associated with the redundancy in processes and equipment that was essential to managing that risk
- Controlling construction costs at a time of very high competition for materials and labour in western Canada, primarily due to a very high level of oil and gas activity.

Consideration is given in the report to the issues SaskPower will face as it contemplates the future of its coal-power generation fleet, given new Regulations that require CCS retrofitting installation during 2019–2043:

Would retrofitting existing infrastructure to generate clean coal power be comparable to power generation alternatives such as NGCC, wind and hydro?

- **HAVE** there been any regulatory changes that might impact decisions?
- **WHICH** existing coal-fired power plants would be the best target(s) for retrofitting?

- **WOULD** there be an opportunity to replicate the BD3 retrofitting design at other power plants?
- **WOULD** there be any other commercially–proven carbon capture technologies to consider?
- **WHAT** would be the appropriate level of capture? What would be the associated plant operating strategies?
- **WHAT** efficiency improvements could be made?
- **WHAT** technology risk-reducing, redundant equipment could be eliminated versus BD3?
- **HOW** could construction costs be reduced?
- **HOW** could SaskPower help build an enhanced market for by-products?

A series of issues and questions is presented in the report that could assist parties outside Saskatchewan contemplate the applicability of the BD3 ICCS project to their unique set of jurisdictional circumstances. These involve regulations, business and market factors, technical design, and construction.

The report concludes with a discussion of SaskPower's CCS research activities—past, present and future—to develop and validate new technologies to mitigate environmental impacts associated with GHGs, SO_2,

NO_X, mercury and particulates. The aim has always been to reduce capital and operating costs, improve reliability and operability, enhance knowledge and understanding, and manage technology risk.

These research activities have been/continue to be:

Bench and pilot-scale testing of capture technologies to further their development and/or to build a database of scalable engineering factors essential to commercialization through:

- The SaskPower Carbon Capture Test Facility (CCTF) that was opened at the Shand Power Station in June 2015.
- The SaskPower Emissions Control Research Facility (ECRF) at the Poplar River Power Station where mercury control technologies were validated in the early 2000s. It is used to continue the testing of capture technologies and associated systems.
- Investments in proving CO_2 geological storage through the IEAGHG Weyburn- Midale CO_2 Monitoring and Storage Project (2000–2012) and Aquistore (2009–2017).

As of Mid-2015, SaskPower is contemplating a new CCS Consortium that may include collaborative opportunities for participants, pending suitable alignment, on: technology, research, regulatory affairs and government relations, and all aspects of project management through design and construction.

The BD3 ICCS project has, to date, garnered many awards. It can be regarded a success. The project has proven to the world that commercial–scale carbon dioxide capture at a coal-fired power generating station is possible rather than an elusive future option. SaskPower has led the way. It is now up to the rest of the world to follow this remarkable pioneer to ensure that the anthropogenic carbon emissions associated with fossil-fuel power generation and use are significantly reduced worldwide.

2015-03 CARBON CAPTURE AND STORAGE CLUSTER PROJECTS: REVIEW AND FUTURE OPPORTUNITIES

Key messages

- The most successful clusters remain those based on the use of CO_2 for EOR application.
- A major obstacle in early years is maintaining a core organisation which is able to carry a CCS cluster project forwards.
- Pre-investment in pipelines and storage may be essential to generate the confidence needed for investment decisions on capture facilities to be made.
- New methods to attract international investment in CCS capacity are needed to exploit the full low cost potential of the best cluster locations.
- Workshops are proposed to explore more systematic development of business plans for CCS clusters with emphasis on customers and revenues.

Introduction

The main objectives of the study are to identify the gaps, risks and challenges faced by regions developing a carbon capture and storage (CCS) cluster, to compare business models with the aim of revealing factors for success and to consider the characteristics which would make new locations suitable for a CCS cluster.

IEAGHG commissioned this analysis to Mike Haines, Cofree Technology Ltd (UK).

Approach

The study was in the form of a literature review and is thus based on publicly available information. A CCS cluster was taken to mean any development which has been proposed or implemented in which multiple sources of captured CO_2 share infrastructure, usually the transport system but also capture and storage facilities. Although this definition would classify as few as two sources sharing as being a cluster, most cluster plans involve a much greater number of sources.

The approach to collecting data for comparison was to construct a database which included fields for technical, cost and business planning information. A

preliminary collection of literature was made jointly with IEAGHG staff on the basis of which the most significant clusters for in depth study were identified. A further check was made in four global CCS project databases to identify any other integrated CCS projects which might qualify as being a cluster.

The database was developed essentially as a questionnaire for internal use to aid the search for relevant information. Particular attention was paid to business planning as this is seen as a key element in the eventual success of CCS cluster proposals. To facilitate discovery and collection of information on business plans a modern business planning method was chosen and used to generate the lists of data to be sought for the analysis. The reader is referred to the main report for details of the business planning template which was used. Sources of technical and commercial information were a mixture of scientific papers, published studies, presentations and news articles.

The information collected was used to generate a narrative description of the main technical characteristics of each significant cluster and the status of its business plan. For less developed initiatives relating to CCS clusters more general narratives were prepared. The key references containing the information used are given. Based on this information the technological and commercial gaps, barriers and challenges which stand in the way of development of successful CCS businesses using a cluster approach are explored. Finally the information on development of existing clusters is used to define the attributes of sites and regions most favourable for the development of new CCS cluster businesses.

Results and Discussion

Detailed descriptions of the following 12 cluster projects, see also Fig 1, were prepared:

- Rotterdam (ROAD and RCP), The Netherlands
- Skagerrak/Kattegat, Scandinavia
- Alberta (ACTL), Canada
- Yorkshire & Humber, UK
- Teesside, UK
- Collie, Australia
- Denver City, USA

- Gulf Coast, USA
- Rocky Mountain, USA
- Shenzhen City, China
- Marseille (VASCO), France
- Le Havre (COCATE), France

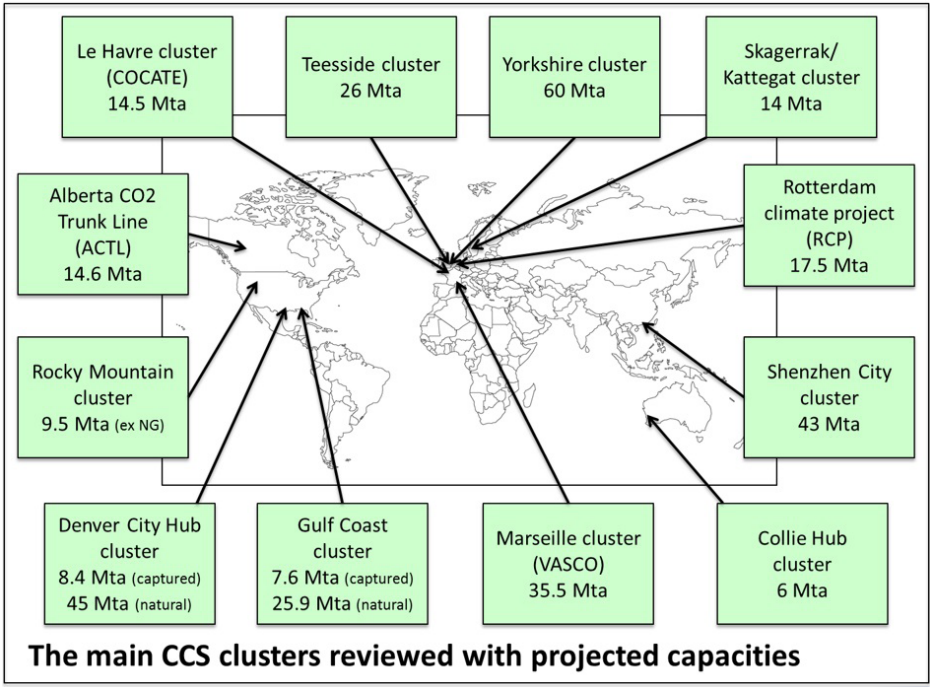

Figure 1, Map of Clusters Reviewed

The maximum projected CO_2 capture capacity of these twelve clusters amounts to about 272 million tonnes per year. Of this about 17 million tonnes is separated during natural gas production. In addition, approximately 51 million tonnes of natural CO_2 are produced in the two largest USA clusters.

More general information was found on proposals for other clusters in the USA and the Iberian Peninsula and also on the prospects for clustering in Germany.

The individual project details are outlined in the executive summary of the report and will not be discussed further in this overview.

Gaps, Risks and Challenges

The most important results of this study are the information and insights which can be derived from the analysis and comparison of the cluster projects. These projects range from the mature systems in the USA to projects which are moving through design towards implementation of initial phases to proposals at the early concept stage. This analysis revealed both technical and commercial gaps, risks and challenge which are briefly summarized below.

Gaps

Revenue gap – 50% or more Government support is likely to be needed to implement first stages of cluster projects.

Possible remedies are:

- Use of Contracts for difference (CfD)
- Higher levels of direct State funding
- Coupling CCS with future enhanced oil recovery (EOR) benefits to satisfy World Trade Organisation (WTO) and other State aid rules
- Sell cluster's long term reduction capacity benefits globally (New financial instruments needed and recognized long term international certificate trade.)

Monetizing CO_2 stored through EOR – Whilst technically the monitoring technologies needed are well developed, the measurement, monitoring and verification protocols for CO_2-EOR need to be established so that tradable emission reduction certificates can be generated and monetized when CO_2 is stored during an EOR operation.

CO_2 shipping – Shipping forms a part of several cluster plans mainly to aid incremental expansion and to access remote sources and sinks. Also shipping may play a role in offshore EOR. Some development is needed to deploy large dedicated CO_2 ships.

Offshore EOR – Cheaper and more flexible methods for implementing offshore EOR to tap revenues from this resource.

Possible solutions are to:

- Develop floating EOR systems
- Develop rapid CO_2 ship to EOR unloading and CO_2 reheating systems

CO_2 pipeline safety – Larger inventories of cluster transport networks will increase risks. Cost effective methods to model and minimize releases and to monitor integrity need to be developed although these are already issues for smaller point to point projects.

Risks

The main risks for clusters are commercial. The following were identified and options to reduce them are discussed in the main report:

- Collapse of CO_2 reduction certificate prices
- Major CO_2 pipeline accident in the industry
- Loss of customers and/or withdrawal of a key partner
- Loss of a storage site
- Extensive delays in implementation
- Failure to gain key permissions
- Alternative EOR methods become more cost effective

Challenges

The following commercial challenges were identified and are discussed in the report:

- Business organisation – Finding the best way to organise diverse partners with different interests and expertise.
- Business globalisation – Finding ways to market the low cost advantages which clusters have to a wider clientele than that of the local businesses. Finding ways to deploy cluster expertise in multiple cluster locations.
- Maintaining momentum – Funding the core organisations for the extended period needed to proceed to implementation and retaining high calibre staff.
- Enabling incremental expansion – Finding ways to allow sources to commit to emission reductions incrementally to reduce their risks.
- Setting up specialist services – Providing more efficient specialist services

on a global scale rather than having them in house.

- Managing confidential data – Finding ways to collect key but commercially sensitive data about emission sources.
- Identifying and connecting with "customers" – Broadening the customer base from those with emission sources to all stakeholders with interests in emission reduction.
- Developing EOR and storage businesses together – Tackling the diverse interests of those engaged in emission reduction and EOR activities including the widest definition of stakeholders.

Business Cases

The key elements of the 12 cluster project business cases are discussed and assessments made of the maturity of each element. A dashboard representation of maturity is also presented for each cluster similar to the example in Fig 2. This enables a high level overview of each cluster's business plan maturity to be seen at a glance. Details of the categories and scoring are in the main report. In general it was found that the customer/revenue plans are less developed than plans for resources and costs. This is understandable because of the technical complexity and novelty of the CCS industry and because the elements are more difficult to address

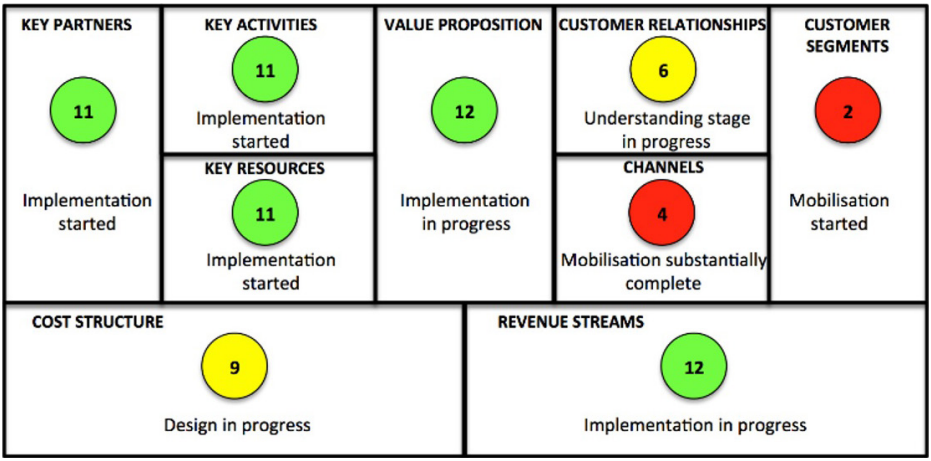

Figure 2, Example Business Plan Dashboard

New CCS Cluster Locations

The report describes positive and negative factors which influence where new CCS clusters may develop. Amongst these are existence of opportunities for CO_2-EOR and countries amenable to provision of substantial State funding. Availability of CO_2 from gasification and a general low cost CCS chain arrangement of sources and sinks are other positive factors. Negative factors include regions where heavy industry is tending to migrate and where discovery of shale gas offers an alternative method of emission reduction. Mexico, Indonesia, oil producing regions of Russia and the countries of the Former Soviet Union and certain locations in China appear to best fit the criteria for new CCS clusters.

Expert Reviewers' Comments

The draft report was reviewed by five experts. Their impressions of the report, particularly the insights into business plans, were positive. They also provided useful additional information about some of the clusters which was incorporated into the report. Some reviewers commented that they felt that the report underestimated the value of underlying Government fiscal support through regulation and taxation rules which underpinned the development of CO_2-EOR clusters in the USA more than might be apparent at first sight. A number of other points were raised. It was suggested that use of a discount rate of 10% for evaluating pre-investment in pipeline infrastructure was too high and that a lower rate should be used for such strategic investments. It was also suggested that there is a significant but less tangible value in the pre-investment in pipelines and storage, as bringing these into existence generates the confidence needed for investment decisions on capture facilities to be made. Reviewers felt that a number of the issues covered in the report applied equally to point to point projects and that it was not entirely clear which were related to cluster projects alone. The text was modified to make this clearer. As a result of comments, reference to the recently published work by the Zero Emissions Platform (ZEP) on business models for transport and storage was added.

Several reviewers were concerned about how the emergency response zone proposed for the Alberta CO_2 Trunk Line was described in the draft text. The text was modified to make the purpose of the zone clearer. This raises

the important issue of public confidence and information in relation to pipeline safety. In particular that the size of the area within which it would be responsible to publicise emergency plans will be much larger than that in which significant risks are present.

One reviewer felt that more specific recommendations could be made in relation to Government policy to provide more balanced support for CCS in the context of the integrated energy system and for extension of such mechanisms as feed in tariffs to cover CCS. However this is beyond the remit of this report.

Conclusions

The most successful clusters remain those based on the use of CO_2 for EOR application. Whilst clustering may slightly reduce costs, the savings are insufficient to fill the cost - revenue gap so that substantial Government support in one form or another will be required.

The cost savings which a CCS cluster can make from sharing pipelines and storage are relatively small but there is potentially a much larger value in this pre-investment as it will generate the confidence needed for multiple sources to plan and implement CO_2 capture. Savings from sharing are much greater where pipelines are offshore or long but locations which have to use such routes are less attractive because of the extra transport costs. Further savings may accrue from sharing organisational costs, gaining public acceptance and providing specialist services. Clustering does not appear to offer direct reductions in the cost of capture particularly for the major sources in a cluster. There may be some potential for reductions for smaller sources if these can be aggregated into larger capture facilities or if these can utilize hydrogen as fuel from a centralized pre-combustion capture facility.

A major obstacle in early years is maintaining a core organisation which is able to carry a CCS cluster project forwards. This can only be overcome if long term funding is committed so that key staff can be engaged and retained. In the long term the costs of this will be minor compared to the total investment in a CCS cluster.

Promising CCS cluster locations should be in a position to attract international funding and not just rely on providing the CO_2 capture service on a local basis.

Mechanisms and structures to allow this widening of support are absent and need to be put in place for CCS clusters to succeed. The prospect of buying-in long term to the lowest cost emission reduction opportunities should be very attractive to some organisations with long term vision and financial capacity. Instruments to facilitate such cross border investment in low emissions need to be developed. Not only would these promote such long term investment, they would also allow much smaller tranches of capacity to be shared and risks to be spread.

Recommendations

The results and conclusions of this study lead to the following recommendations regarding future activities that IEAGHG can initiate:

1. Commission a study with a leading specialist financial institution to propose and develop financial instruments and forms of contract which would allow long term investments in CCS clusters and their lifetime benefits to be traded and exchanged internationally.
2. Promote more systematic development of business plans for CCS with emphasis on customers and revenues to complement efforts being made on technical, environmental, safety and public acceptance issues. Workshops and webinars are suggested as the most effective means of initiating this collaboration.

2015-02 REVIEW OF OFFSHORE MONITORING FOR CCS PROJECTS

Key Messages

- A range of monitoring techniques are available for CO_2 geological storage offshore, both deep-focussed (providing surveillance of the reservoir and deeper overburden) and shallow-focussed (providing surveillance of the near seabed, seabed and water-column).
- Deep-focussed operational monitoring systems have been deployed for a number of years at Sleipner, Snøhvit and also at the pilot-scale K12-B project in the offshore Netherlands, and conclusions regarding the efficacy of key technologies are starting to emerge. 3D seismic surveys have been highly effective for tracking CO_2 plume development in Sleipner and Snøhvit reservoirs. Measurement of downhole pressure was crucial in establishing non-conformance at Snøhvit. A combination of 3D seismic and downhole pressure / temperature monitoring at Snøhvit has demonstrated the benefit of complementary techniques.
- Shallow-focussed monitoring systems are being developed and demonstrated. New marine sensor and existing underwater platform technology such as Automated Underwater Vehicles (AUVs) and mini-Remotely Operated Vehicles (Mini-ROVs) enable deployment and observation over large areas at potentially relatively low cost. Seafloor and ocean monitoring technologies can detect both dissolved phase CO_2 and precursor fluids (using chemical analysis) and gas phase CO_2.
- Developments in geophysical techniques, such as the P-Cable seismic system for higher resolution 3D data collection in the overburden, have been demonstrated successfully and effective integration of these shallow subsurface technologies with the seabed monitoring data can help to understand shallow migration processes.
- Controlled release sites such as QICS[1] have proved to be useful test-beds for shallow seismic techniques and acoustic detection systems. They can also reveal how CO_2 migrates through, and is partially retained by, unconsolidated sediments.
- Monitoring strategies need to be devised to cover large areas, typically tens to hundreds of km^2 and also achieve accurate measurement and

[1] *QICS = Quantifying and Monitoring Potential Ecosystem Impacts of Geological Carbon Storage

characterisation possibly over lengthy periods. Limited spatial coverage could lead to the risk that anomalies remain undetected or are only detected after a lengthy period of time. Ameliorative measures might then be harder to implement.

- Search areas could be narrowed down by the integration of information from deeper-focussed monitoring such as 3D seismics, which can identify migration pathways, with shallow surface monitoring such as acoustic detection.
- Assessment of the results from both the operational (predominantly deep-focussed) and research (predominantly shallow-focussed) monitoring activities from Sleipner and Snøhvit indicates that many elements of the European storage requirements have been met at these large-scale sites which were both initiated before the CCS Directive was introduced.

Background to the Study

Since the inception of CO_2 injection into the Sleipner gas field in 1996 there has been considerable progress in monitoring offshore geological storage sites. There have also been recent developments, in-situ experiments, large-scale tests, and reviews on monitoring techniques for offshore monitoring applications. Some of these developments have occurred outside of the CCS sector. This is in addition to the deep monitoring for Statoil's Sleipner project in the North Sea and Snøhvit project in the Barents Sea.

In addition to technology developments there has been a corresponding series of regulations and related objectives which are designed to ensure that CO_2 storage in offshore reservoirs can be retained within secure repositories without detrimental environmental effects. As with onshore CO_2 geological storage, the objectives for offshore monitoring include: CO_2 geological storage performance, baseline studies, leakage detection, and flux emission quantification. There are advantages and disadvantages of offshore monitoring compared to onshore. There is better and more consistent seismic coupling to the geology because of the water contact, there are less access issues in terms of landowners and infrastructure. In addition, emissions at the seabed can be both 'seen' and 'heard' as bubble streams. On the other hand, there are the challenges of working in a more remote and hostile marine environment.

Sub-seabed geologic storage sites will have large spatial seafloor extent and large overlying ocean volumes (with potentially dispersed and localised emission sources) which provides a monitoring challenge. One requirement of any offshore leakage monitoring strategy development is to ensure wide area monitoring combined with sensitive detection thresholds. Potential CO_2 leakage may have precursor fluid release of chemically-reducing sediment pore fluids and aquifer brines (each of which has a unique chemical signature). New marine sensor and existing underwater platform technology such as Automated Underwater Vehicles (AUVs) and mini-Remotely Operated Vehicles (Mini-ROVs) and seabed landers are under development to enable deployment and observation over large areas at potentially relatively low cost. Seafloor and ocean monitoring technologies can detect both dissolved phase CO_2 and precursor fluids (using chemical analysis) and gas phase CO_2 and seabed. Such chemical and physical monitoring systems may also provide tractable and robust methods for quantifying leakage loss beyond just detection.

Developments in geophysical techniques, such as the P-Cable seismic system for higher resolution 3D data collection in the overburden, have been demonstrated successfully in the last few years and effective integration of these shallow subsurface technologies with the seabed monitoring data can help to understand shallow migration processes.

Deep-focussed monitoring of reservoir and overburden has proved successful offshore, notably at Sleipner and Snøhvit. This study has reviewed and assessed the performance of these monitoring technologies and methodologies tools, and how new or modified tools might contribute to monitoring capability.

Scope of Work

This report reviews offshore monitoring practice for CO_2 storage projects in terms of tool capabilities, logistical practicalities and costs. The focus is on large-scale 'commercial' storage monitoring and draws together published experience from existing large offshore CO_2 storage sites as well as monitoring research at experimental test sites and in areas of natural CO_2 seepages. The strengths and limitations of monitoring techniques, strategies and methodologies are discussed, and relevant experience from

onshore sites are also included. Monitoring over the full life-cycle from pre-injection (baseline) through injection and post-injection phases to transfer of responsibility to the competent authority is considered. The review draws on selected examples of current or planned monitoring practice.

Current regulatory and technical requirements for large-scale offshore CO_2 storage (for Europe, Australia, Japan and the United States) are summarised. The objectives, capabilities, practicalities and costs of the monitoring techniques deployed at operational (or planned) offshore CO_2 storage sites are assessed. Monitoring experience gained from experimental and natural analogue sites and modelling studies have also been reviewed. The efficacy of current (and planned) offshore monitoring plans with respect to regulatory requirements have been investigated. The report concludes with a synthesis of a sample offshore monitoring strategy and template to improve meeting regulatory needs in a cost-effective manner.

Additional insights have been provided by comparisons with equivalent onshore monitoring practice. Technology gaps and synergies have been included. The report also gives recommendations on priorities for further research and development.

Findings of the Study

Offshore Regulation and Monitoring Objectives

There are two key over-arching regulations that cover offshore CO_2 storage. The London Protocol and the OSPAR[2] Convention. The London Protocol, which is a global agreement to protect the marine environment by regulating waste disposal at sea. It was amended in 2006 to include CO_2 storage. Both of these conventions have similar two-stage monitoring guidelines. The first stage covers the performance of monitoring of CO_2 within storage formations and the second deals with the environmental impact in the event that leakage is suspected. The implications mean that impacts on the sea floor and marine communities need to be ascertained.

It is in Europe that the regulatory framework is most mature but offshore storage regulations also exist and are developing elsewhere, notably in Japan, Australia and the Unites States. Although drafted at various levels of

[2] OSPAR is so named because of the original Oslo and Paris Conventions ("OS" for Oslo and "PAR" for Paris)

detail, the regulatory documents from the different national jurisdictions all emphasise the key role of monitoring and the range of objectives it should serve. These can be broadly distilled as demonstrating that the storage site is performing effectively and safely and that it will continue to do so into the future. This approach can therefore be expressed as providing assurance of containment and conformance.

Since 2007 the international regulatory framework has been evolving notably in Europe with the introduction of the European Storage Directive for CO_2. These regulations will be particularly pertinent to the planned projects Peterhead - Goldeneye, White Rose and ROAD. Sleipner, Snøhvit and K12-B predate current EU legislation. The EC Storage Directive specifically addresses monitoring for the purposes of assessing whether injected CO_2 is behaving as expected, whether any migration or leakage occurs, and if this is damaging the environment or human health.

OSPAR is primarily focussed on detecting and avoiding leakage and emissions and therefore identifies the following objectives for a monitoring programme:

- Monitoring for performance confirmation.
- Monitoring to detect possible leakages.
- Monitoring of local environmental impacts on ecosystems.
- Monitoring of the effectiveness of CO_2 storage as a greenhouse gas mitigation technology.

The following essential elements of monitoring and control are stated as required to help achieve these objectives:

- The injection rate.
- Continuous pressure monitoring.
- Injectivity and pressure fall-off testing.
- The properties of the injected fluid (including temperature and solid content, the presence of incidental associated substances and the phase of the CO_2 stream).
- Mechanical integrity of seals and (abandoned) wells.
- Containment of the CO_2 stream including performance monitoring and monitoring in overlying formations to detect leakage.

- Control measures, overpressure and emergency shutdown system.

It is clear from the wide range of regulatory requirements that have been developed, but regulation has reached different stages of maturity across the world. There are two relatively consistent monitoring-related themes: the requirement firstly to demonstrate that a storage site is currently performing effectively and safely; and secondly to ensure that it continues to do via the provision of information supporting robust prediction of future performance.

These requirements for monitoring offshore storage can be distilled into a number of necessary actions (Table A1), which fall within two main monitoring objectives, containment assurance and conformance assurance. A third category, contingency monitoring may be required in the event that containment and/or conformance requirements are not met. The categories and requirements shown in this table are an interpretation by the authors of the report.

		OSPAR	EU Directive	EU ETS	
Deep-focussed monitoring actions	Migration in overburden				Containment
	Containment integrity				Containment
	Migration in reservoir				Conformance
	Performance testing and calibration and identification of irregularities				Conformance
	Calibration for long-term prediction				Conformance
	Testing remedial actions				Contingency
Shallow-focussed monitoring actions	Verification of no leakage				Containment
	Leakage detection				Containment
	Emissions quantification				Contingency
	Environmental impacts				Other
	Testing remedial actions				Contingency

Figure 2, Example Business Plan Dashboard

In terms of the types of monitoring tools used, it is sometimes convenient to categorise them as deep-focussed (providing surveillance of the reservoir and deeper overburden) and shallow-focussed (providing surveillance of the near seabed, seabed and water-column).

Experience at Current and Operational CO_2 Storage Sites

The report outline results from the monitoring programmes that are being currently deployed in Europe at the world's two large-scale offshore storage sites: Sleipner and Snøhvit, as well as the smaller, pilot-scale project at K12-B. It has also reviewed the monitoring tools that are proposed for the Peterhead - Goldeneye project in the UK, the ROAD project in the Netherlands, and the Tomakomai project in Japan.

The monitoring objectives at Sleipner are linked closely to the identified storage risks: migration through the geological seals resulting in leak pathways to the seabed; lateral migration into wellbores, resulting in leak pathways to the seabed and lateral migration of CO_2 outside of the Sleipner license area. The monitoring programme is primarily based around tracking CO_2 migration in the storage reservoir in order to predict future behaviour and providing the capability to reliably detect changes in the overburden which might indicate out of reservoir movement of CO_2. These objectives were all addressed through the application of time-lapse 3D seismics. Although predating the European legislation, the monitoring programme at Sleipner does address the main high level requirements of containment and conformance in a number of ways. Table A2 (please see page 46 for double spread) summarises the monitoring surveys deployed at Sleipner between 1994 and 2013.

Throughout its operation the Sleipner field has been used as a test bed for other monitoring technologies (summarised in Table A2 - please see page 46 for double spread).

At Snøhvit the main monitoring aims are firstly to ensure that injection pressures do not exceed the fracture threshold of the caprock and secondly to track the CO_2 plume. Two deep-focussed monitoring technologies have been deployed at Snøhvit: downhole pressure and temperature monitoring; and time-lapse 3D seismic surveys. In addition a number of shallow-focussed research surveys have also been carried out as part of the ECO_2 project. These

surveys include multibeam echo-sounding, conductivity and temperature depth profiles, sediment sampling and water column sampling.

Longer term measurement of downhole pressure was crucial in establishing non-conformance at Snøhvit. The long-term pressure increase was faster than expected and eventually threatened the geomechanical stability of the storage formation as fluid pressures approached the estimated fracture pressure. In addition, modelling of the pressure decay (or fall-off) curves, which followed cessations in injection, indicated that the capacity of the storage reservoir was smaller than expected, likely due to no-flow barriers a few kilometers from the injection well. The most complete understanding of reservoir performance came from a combination of the accurate, integrative pressure measurements and the positional imaging ability of the time-lapse seismics. The operators were therefore able to implement an alternative storage plan by switching to an alternative reservoir.

Peterhead - Goldeneye has a monitoring programme that is designed to meet European offshore requirements that covers both deep and shallow focussed monitoring. The deep-focussed component will include surveillance of the reservoir and overburden and utilises a number of proven technologies: time-lapse 3D seismics; down-hole pressure and temperature; geophysical logging and fluid sampling. A comprehensive shallow environmental monitoring programme is also planned, including seabed imaging, seabed sampling and seawater sampling technologies. Contingency monitoring is also addressed, for example a P-Cable seismic survey to help image and understand shallow migration in the event of leakage being detected at the top of the storage complex.

The Dutch ROAD project is the first project to be permitted under the EU Storage Directive. The permit is subject to updates and the inclusion of more detail. Further study is underway to assess specific local pressure build-ups, pressure barriers and later-stage fault leakage. Results will be used to update the risk assessment which will feed into the updated monitoring plan to provide evidence for containment and to demonstrate integrity of seals, faults and wells.

Table A2, Research monitoring tools are shown in italics. Green denotes deep-focused techniques that operate that for years with more than one survey, the amount of CO_2 injected for each specific survey is stated: thus "s"

Monitoring Technique	1994	1995	1996	1997	1998	1999	2000	2001	2002
3D Surface Seismic	✔					✔		✔	✔
2D Surface Seismic (High-Res)									
Seabed Gravity									✔
CSEM									
Wellhead Pressure									
Seabed Imagine (as sonar, multibeam, pinger)									
Sediment Sampling				✔			✔		
Water Column Sampling, Bubble Stream Chemistry									
Cumulative CO_2 Injected at Survey (Mt)	0.00		Injection Starts			2.35		4.25	4.97 (s) 5.19 (g)

The Japanese Tomakomai CCS project is a large scale demonstration project located 3 - 4 km off the coast of Hokkaido. The monitoring programme includes 2D and 3D seismic surveys. These will be deployed via ocean bottom cables (OBC) because greater repeatability is achievable and the busy port precluded streamer deployment. The 2D survey line aligns with the two injection wells and uses a buried OBC for similar reasons. Heavy emphasis has been placed on the detection of natural earthquakes and

from the surface, yellow denotes well-based techniques and blue denotes shallow-focused techniques. Note denotes "seismic", "g" gravimetric, and "em" electromagnetic surveys.

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	✓		✓		✓		✓		✓	
		✓				✓				✓
					✓					
Continous										
			✓					✓	✓	✓
✓			✓					✓	✓	✓
								✓	✓	✓
	6.84	7.74	8.40		10.15 (s) 10.36 (em)	11.05	12.06			~14

microseismicity which also uses the OBC, in addition to 4 dedicated ocean bottom seismometers (OBS) and downhole sensors in the observation wells.

The report covers the monitoring techniques commonly used to verify containment and conformance. A summary of these techniques, and where they have been deployed or planned, has been compiled by IEAGHG and is presented in Table A3 (please see table on page 48 to page 56 for full data).

Table A3 - Surface Seismic Methods

Method	Streamer – 3D Seismic	Streamer 2D Seismic	Streamer – P Cable Seismic	Chirps, Boomers & Pingers	Ocean Bottom Nodes (OBN) & Cables (OBC)
Capabilities	High detection & resolution capabilities. Data suitable for advance analysis especially the investigation of reservoir properties & plume tracking	High detection & resolution capabilities similar to 3D seismic. Star survey configuration can provide image of plume spread.	High resolution 3D seismic system suited to shallow sections (<1,000 m) therefore useful for imaging shallow overburden. High spatial and temporal resolution possible Useful for 3D mapping of structures especially faults.	Designed for very high resolution surface seismic surveys direct detection of bubble-streams may be possible in favourable circumstances.	As static observation data recorders these devices can provide full azimuth coverage with multicomponent sensors with p and s-wave recording for geomechanical & isotropy characterisation. Long-term recording is useful for detecting natural & induce seismicity
Practicalities	Routine deployment, robust & mature but requires large unobstructed areas of sea Detection threshold depends on geometry of CO_2 accumulation	More compact compared to 3D. Time-lapse is reputedly poor.	Relatively compact and short than 3D & 2D configurations gives high manoeuvrability.	Can be deployed from small site-survey vessels. AUV systems can be equipped with Chirp transducers. AUV survey has detected clear images of natural gas pockets in central North Sea	Can provided information in close proximity to platforms
Deployment	Sleipner, Snøhvit. Planned for Goldeneye, ROAD, Tomakomai*	Sleipner, Tomakomai (OBC 2D seismic)	Snøhvit, Gulf of Mexico	Sleipner, planned for Goldeneye	OBN planned at Goldeneye OBC planned at Tomakomai
Containment Monitoring	Can provide robust & uniform spatial surveillance of storage complexes. Can detect small changes in fluid content & therefore useful for leakage detection. Changes in time-lapse seismic images can detect small quantities of CO_2.		Useful for containment risk assessment & leakage monitoring by tracking CO_2 migration above storage complexes		

Method	Streamer – 3D Seismic	Streamer 2D Seismic	Streamer – P Cable Seismic	Chirps, Boomers & Pingers	Ocean Bottom Nodes (OBN) & Cables (OBC)
Conformance	Ability to track CO_2 plumes is useful to corroborate model predictions and can be used to refine or modify them. Plume mobility & storage efficiency can be checked. Measured time-shifts can reveal indicative pressure changes in reservoirs.				
Cost	£10M+ depending on survey area, specification, and locality. Processing time up to £1M in computing time	<£1m depending on survey area, specification, locality	<£1m depending on survey area, specification, locality	<£100k	£10M+ but unlike streamer surveys there is a high initial cost to set up the system and relatively low costs for repeat surveys.
Limitations	Lack of significant azimuthal variation in wave propagation which limits azimuthal analysis for evaluation of anisotropy & geomechnical integrity. Interpretation & detection of CO_2 relies on good repeatability which may not always occur.	Lack of 3D migration in processing precludes optimum imaging of some subsurface structures.	Sea bed multiple can obscure important features. Vulnerable to reduced performance in poor sea conditions.	Designed for shallow surface surveys. AUV based systems have limited penetration due to lower power availability.	Vulnerability to trawling operations. Limited spatial sampling density compared with streamer surveys.

Table A3 - Downhole seismic methods

Method	4D VSP (Vertical Seismic Profiling)	Passive Seismic Monitoring
Capabilities	High resolution imaging of near-wellbore region 10s – 100s metres radius	Allows continuous monitoring for microseismic events
Practicalities	Permanent downhole sensors allow for cost-effective time-lapse imaging. Data processing can be complex. Fibre-optic acoustic cable might improve reliability.	Deployment in one or more shallow wells (<200m). Microseismic events can be used to identify structures such as faults and fractures. Important to establish natural background seismicity to distinguish events related to CO_2 injection & migration.
Deployment	Goldeneye (under consideration)	Planned for ROAD and Tomakomai Considered for Goldeneye
Containment Monitoring		
Conformance		Important to establish natural background seismicity to distinguish events related to CO_2 injection & migration.
Cost		High initial costs required for deployment. Maintenance costs could also be high
Limitations	Coverage is non-uniform (spatially variable offsets & azimuths) which can make interpretation difficult. Time-lapse repeatability is uncertain. Reliability of sensors is a key issue.	Sensor reliability can make the method vulnerable leading to potentially limited signal records.

Table A3 - Potential field methods

Method	Seabottom Gravimetry	Controlled Source Electromagnetics (CSEM)
Capabilities	Directly measures mass change within reservoirs which is a conformance-related parameter	Can provide complementary information to seismics. Method is sensitive to fluid saturation at higher CO_2 saturation levels
Practicalities	Offshore deployment is logistically complex requiring ROV and boat support to emplace concrete benchmarks	Offshore deployment is logistically complex
Deployment	Sleipner	Sleipner
Containment Monitoring		
Conformance		
Cost	Low compared to 3D streamer surveys. A 50 station near-shore survey would cost ~£1M	Costs high & comparable with offshore 3D seismics.
Limitations		The technique is severely hampered in shallow water (<300m).

Table A3 - Downhole measurements

Method	Downhole Pressure and Temperature	Geophysical Logging	Wellbore Integrity Monitoring	Downhole Fluid Sampling.	Chemical Tracers and Gas Analyses
Capabilities	Downhole gauges are capable of detecting very small temperature and pressure changes which are a primary method for monitoring injected CO_2 physical properties and reservoir performance. Position of gauge across permeable units can give indications of out-of-reservoir migration.	Standard oilfield technique used for calculating CO_2 saturation. Provided there is a good baseline survey, repeat surveys can be used to calculate CO_2 saturations	Standard oilfield technique including cement bond logs used to check integrity of the cased wellbore. Quality and availability of legacy data from abandoned wells may limit effectiveness of integrity checks. Ultrasonic imaging, Multi-finger calliper and Electromagnetic imaging, downhole video and real time borehole stress and tubing/ casing deformation imaging are used to check casing and tubing integrity.	Analyses of reservoir fluids can yield pCO_2,pH HCO_3-, dissolved gases, stable isotopes and tracers	Tracers and isotopic signatures can help to identify CO_2 origin and monitor migration or potential leakage.
Practicalities	Deployment is a requirement under the EU Storage Directive, Long-term surveillance needs to take account of instrument drift and reliability.	Downhole logging is dependent on access to wellbores which might be restricted. Obstructions such as scale accumulation may preclude logging.	Techniques is reliant on access to wells and different operations. Build-up of scale can cause problems by obstructing logging tools.	Sampling should be carried out at ideally at reservoir pressure. Requires access to specific reservoir zones. U-tube is deployed onshore but does not have safety certification for offshore deployment.	Tracers can be injected in a pulse or continuously. Tracers can be detected in extremely small quantities using gas chromatography or mass spectrometry.
Deployment	Snøhvit, K12-B. Planned for Goldeneye, ROAD, Tomakomai	Planned at ROAD and Goldeneye	K12-B, planned at ROAD & Goldeneye	K12-B planned at Goldeneye	K12-B planned at Goldeneye

Method	Downhole Pressure and Temperature	Geophysical Logging	Wellbore Integrity Monitoring	Downhole Fluid Sampling.	Chemical Tracers and Gas Analyses
Containment Monitoring	Key for controlling geomechanical integrity of the reservoir and caprock. Any unexpected pressure reduction in the reservoir could indicate potential leakage.				At Goldeneye use of tracers is being considered to distinguish between natural CO_2 being emitted from the sea bed and CO2 from the storage complex.
Conformance	Essential for monitoring fluid flow performance and model calibration demonstrating reservoir permeability, storage capacity and geomechanical stability.	Pulsed neutron capture logging is planned for Goldeneye to acquire a good baseline and quantify CO_2 thickness interval	Wellbore integrity is essential for long-term CO_2 storage security by preventing leakage. At Goldeneye logs will be run prior to injection to establish a baseline. Integrity will be checked initially in year three and then every five years until injection is completed.	At K12-B analyses of gas samples from two production wells revealed heterogeneous nature of the reservoir. Wireline downhole sampling proposed for Peterhead - Goldeneye.	Tracer studies at K12-B showed breakthrough occurred at two producer wells after 130 days and 463 days depending on distance from the injector. Differing CO_2 and CH_4 solubilities and insoluble tracers mean these breakthrough rates may not reflect real CO_2 migration rates.
Cost	Relatively low <£100 plus installation and retrieval of gauges	Cost varies depending on the suite of logs run	Cost varies depending on the suite of logs run	Onshore cost per sample ~£5-10k per sample.	Noble gases analyses are ~£350 compared with £125 for SF_6
Limitations				Accuracy of breakthrough timing depends on temporal sampling frequency.	

Table A3 - Under sea monitoring

Method	Seabed and Water Column Imaging	Underwater Video	Seabed Displacement Monitoring	Geochemical Water Column Sampling	Sediment Sampling	Ecosystem Response Monitoring
Capabilities	Active acoustic techniques can be effective at detecting gas fluxes. Multibeam echosounders (MBES) can be used for 3D bathymetric surveys. In time-lapse mode method could be used to detect slight changes in seafloor that might be caused by CO_2 leakage. Acoustic bubble detection can identify bubble releases	Detection and recording of high definition images of bubbles and other features such as bacterial mats and biota behaviours which may give an indication of CO_2	Vertical displacements of the seabed can be indicative of pressure changes in reservoirs. GPS system could measure rates with a accuracy range of 1-5mm.	Water column measurements using conductivity, temperature and depth (CTD probes) in combination with pH pCO_2, dissolved O_2, inorganic and organic carbon, nitrogen, phosphate, Eh, salinity can be sued to detect anomalous chemistry.	Time-lapse sediment sampling can be used to detect changes in sediment, pore fluid that could indicate CO_2 leakage. Detecting CO_2 leak induced changes above background requires a good understanding of natural variability	Time-lapse sediment sampling can be used to detect changes in benthic flora and fauna caused by elevated CO_2 concentrations either as a gas phase or by a reduction in pH. Avoidance behaviour needs to be distinguished by changes induced by natural variability
Practicalities	These are established techniques that can be carried out by a survey vessel with multiple imaging systems. This is a cost-effective means of surveying large areas of sea bed. AUV and ROV systems can operate closer to the seabed, the scale and operational duration of surveys is limited the size of the device.	Image quality can vary depending on water quality and height above seabed.	Sensor networks on seafloor that use acoustic ranging techniques, pressure gauges or tiltmeters can give very accurate measurements of seabed movement	CTD probes can be conducted from survey ships. Continuous measurements can be made. Interpreting a leakage signal above background measurements can be extremely challenging. Baseline measurements ideally need to reflect a degree of natural variability.	Quality of sample depends on substrate and whether core has retained pore fluid at the original insitu pressure. Specialist vibrocorer equipment is required.	Species density and variety can be recorded with underwater video.

Method	Seabed and Water Column Imaging	Underwater Video	Seabed Displacement Monitoring	Geochemical Water Column Sampling	Sediment Sampling	Ecosystem Response Monitoring
Deployment	Pervious side-scan sonar, single beam and multibeam echosounding and pinger seabottom profiles were conducted. Surveys at Sleipner and Snøhvit. Pockmarks were clearly identified but no bubble streams. Acoustic bubble detection is planned at ROAD. A MBES plus side-scan sonar is planned for Goldeneye	Sleipner	Planned for Goldeneye. Single GPS station mounted on a platform.	Sleipner and Snøhvit, and planned at Goldeneye (permanently attached to platform) & Tomakomai. A survey over a period 2011 -2013 above Sleipner found no evidence of CO_2.	Sleipner and Snøhvit, and planned at Goldeneye) & Tomakomai. Repeat surveys will be conducted to detect possible changes induced by CO_2 leakage.	At Goldeneye ecosystem sampling using Van Veen Grab is planned.
Containment Monitoring			Monitoring subsidence or uplift can provide evidence of containment and conformance.			
Conformance					Seabed sediment samples from Goldeneye will be analysed for a suite of dissolved gases to provide a background baseline.	
Cost	Surveys 10 km2 cost ~£100k - £200k but cost efficiencies are possible if multiple techniques are carried out.	~£1k-10k	~£1k-10k for single GPS station mounted on a platform.	~£1k – 10k for a survey when deployed from a vessel conducting other surveys	£5k / day for equipment deployment and excluding ship time	~£100s per sample excluding processing and organism identification

Method	Seabed and Water Column Imaging	Underwater Video	Seabed Displacement Monitoring	Geochemical Water Column Sampling	Sediment Sampling	Ecosystem Response Monitoring
Limitations	There is a trade-off between the scale of the survey area and the ability to survey the sea floor from an AUV. Static seabed sensors can achieve high resolutions but over smaller fixed areas. However, they are generally more costly to install, maintain and retrieve compared to mobile equipment.	A highly qualitative technique with a poor ability to resolve the size and shape of bubbles.		The density, timing and the vertical spacing separation of surveys may mean small leakage plumes could remain undetected depending on plume dispersion.		Most effective biomarker species have not yet established.

Experience from experimental and natural seepage sites and modelling.
Natural CO_2 seepage sites are prevalent in several areas around the world and especially in geothermally active areas. The hydrothermally driven seeps off the island of Panarea in the Aeolian Islands are a good example. Observations near these seeps shows that the local biology has adapted to the presence of these seeps, but this adaptation is in distinct contrast to conditions in colder, deeper and more turbid sites. The Hugin Fracture is another example of natural seepage, in this case in the central North Sea. The 3 km long structure is covered by soft sediments with wide patches of methanotrophic bacteria which metabolise methane from a natural seep. There is no evidence of CO_2 at this location. The report also outlines the observations of the QICS artificial CO_2 test injection experiment in Ardmucknish Bay off the west coast of Scotland. CO_2 was released beneath 11m of sediment. Over a period of 37 days. Although bubbles occurred soon after injection CO_2 was retained within sediments and trapped in pore waters. The QICS experiment also clearly revealed the influence of cyclical hydrostatic pressure induced by tides. Acoustic tomography has been tested at Takatomi in Japan. By using dispersed transponders it is possible to detect the location of bubble streams by triangulation. Although the system allows continuous measurement it is

susceptible to biofouling, suspended sediment and trawler damage. One of the main challenges encountered with passive acoustic measurements is the extent of background noise from artificial and natural sources which can mask a specific acoustic signal.

The use of high-resolution seismic reflection using chirp and boomer technology proved highly effective during the QICS experiment. The technique produced clear images of gaseous CO_2 trapped in sediments above the release point (see Figure A1 below).

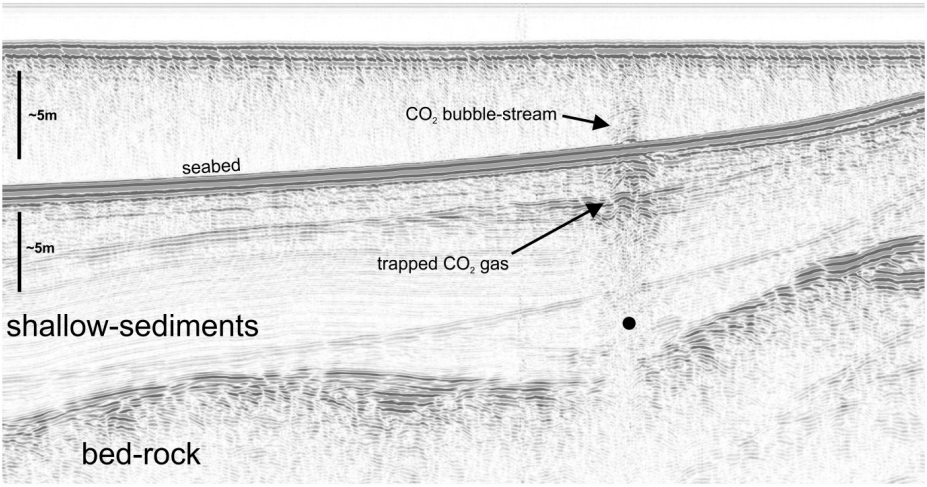

Figure A1 Seismic profile showing gaseous CO_2 trapped in shallow sediments and a bubble stream above the release point

The impact of higher concentrations of CO_2 in seawater has been reviewed. Laboratory and mesocosm studies have shown that an increase in CO_2 in seawater reduces infaunal diversity and alters community structures. The precise nature and severity of the impact is strongly influenced by both sediment type, length of exposure and species-specific sensitivity to environmental changes. The response on benthic communities to CO_2 will be site specific as well as the duration of exposure. However, behavioural alterations might take place through natural seasonal variation and consequently comprehensive baseline studies are necessary to distinguish between natural variability and potential leakage impacts.

Hydrodynamic modelling, which can be used to predict distribution patterns and changes in marine conditions, are widely used for predictive purposes. The models can be used to predict the vertical and lateral spread of CO_2 for example and the likely mixing process but understanding water-column dynamics is essential. Tidal currents are a major agent in many shelf seas where storage is likely to be situated (see Figure A2).

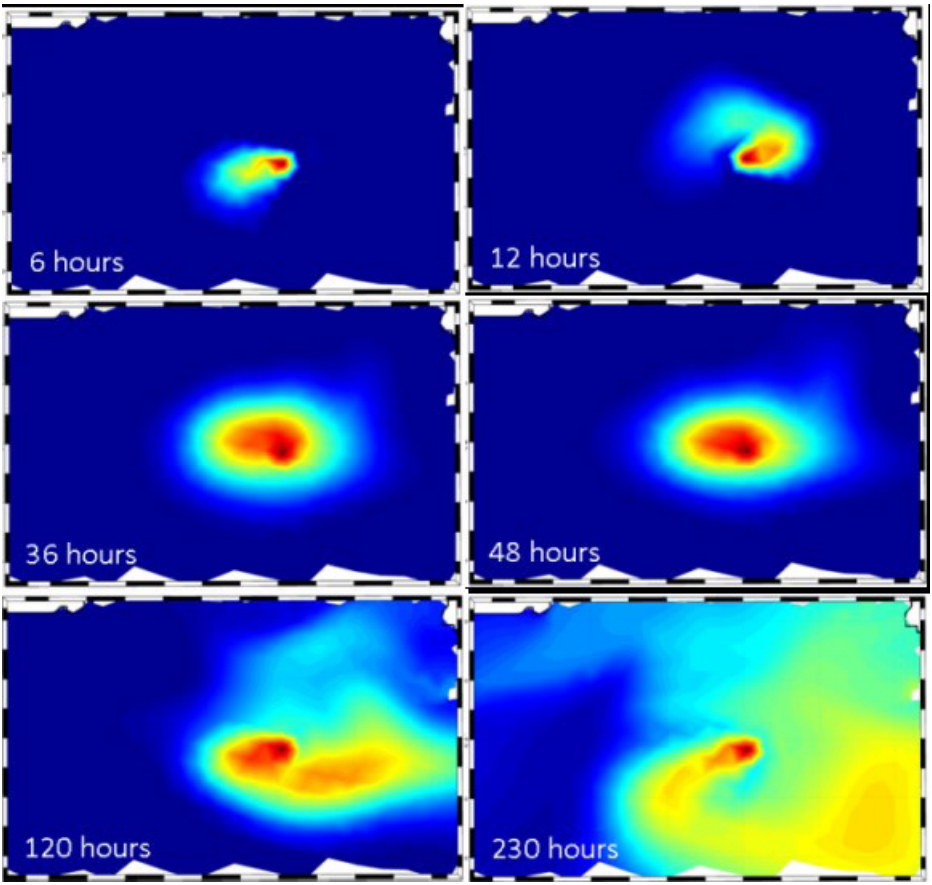

Figure A2, An example of a dispersion plume of dissolved CO_2 from a point source influenced by tidal mixing using the FVCOM[3] model. Red represents the highest concentration of CO_2 whilst dark blue represents the background concentration

[3] Finite Volume Coastal Ocean Model

strategies need to be devised to cover large areas, typically tens to hundreds of km^2 and also achieve accurate measurement and characterisation possibly over lengthy periods. Limited spatial coverage could lead to the risk that anomalies remain undetected or are detected after a lengthy period of time. Monitoring data is used to build a robust baseline but data interpretation can be used to improve the knowledge of storage sites and where anomalies could occur. A combination of point sampling and large spatial surveys should help to improve the quality of monitoring. Search areas could be narrowed down by the integration of information from deeper-focussed monitoring such as 3D seismics, which can identify migration pathways, with shallow surface monitoring such as acoustic detection.

Seasonal variability, seawater chemistry variability and other features such as the presence of shallow gas (CH_4, CO_2, H_2S) in marine sediments need to be considered in any monitoring programme. Other factors such as seabed recycling and sediment transport and anthropogenic activities such as trawling also need to be taken into account.

Expert Review Comments

- Monitoring techniques have to be able to demonstrate conformance. This has been explained where a technique can be used to verify conformance.
- Cost information was too imprecise. Cost information has been included where possible but expressed as a ranges because cost can depend on a number of site-specific factors and whether different techniques can be carried out simultaneously.
- The development of regulations for offshore CO_2 storage was queried. The report includes details of the extent of development by different jurisdictions including US and Japanese examples.
- The structure of the report was changed so that the subject matter is presented in a more fluent sequence and is cross-referred.
- Natural seeps, including hydrocarbons and other gases, need to be distinguished from potential CO_2 leakage from storage sites. The report includes a section on the origin and occurrence of natural seeps.
- The ability to track CO_2 plumes was raised. The report does include good

examples of highly effective tracking and where it is more challenging. It also explores the use of complementary monitoring techniques and demonstrates their effectiveness.

- The potential solutions to the challenges presented by different monitoring techniques was queried. There is a synthesis section and an appendix which discusses R&D priorities that addresses the key challenges.
- Discussion about the monitoring of the Sleipner injection programme and the Hugin Fracture observations have been separated to avoid any misconstrued link between them.

Conclusions

- Dedicated storage regulation was initiated by amendments to the London Protocol and the OSPAR Convention in 2006 and 2007 which put in place for the first time the legislative means for storing CO_2 beneath the seafloor. This was followed by publication of the European Storage Directive in 2009 which set out a comprehensive framework for storage site operation including detailed requirements for monitoring and verification.
- Deep-focussed operational monitoring systems have been deployed for a number of years at Sleipner, Snøhvit and also at the pilot-scale K12-B project in the offshore Netherlands. Time-lapse 3D streamer seismics at both Norwegian sites have proved strikingly effective at both storage sites providing strong capabilities for conformance and containment assurance.
- Downhole pressure monitoring at Snøhvit proved crucial in identifying non-conformant storage behaviour and triggering a modification of injection strategy. At K12-B downhole pressure also proved to be the key tool for conformance history-matching.
- A number of deep-focussed research monitoring tools have been deployed at Sleipner and K-12B. Of these seabed gravimetry has so far perhaps shown the most promise providing indications of natural complementarity with seismics.
- Many tools for the detection of shallow leakage and CO_2 emission at the seabed have been tested at both natural and artificial emission

sites. Shallow monitoring tools fall into three categories, geophysical, chemical and biological. The former principally comprise variants of sonar/echosounding and aim either to detect changes of seabed morphology and reflectivity in time-lapse mode, or to directly detect bubble-streams in the water column. An ongoing research challenge is to quantify bubble fluxes with geophysical methods and both active and passive 'listening' acoustic systems have demonstrated quantitative measurement potential via advanced processing of the bubble-stream measurements. Chemical sampling methods aim to detect and characterise changes in the shallow sediments or seawater column due to emitted CO_2 or precursor fluids from the subsurface. Deployment of all shallow-focussed technologies can be via ship, remotely-operated vehicle (ROV) or automatic underwater vehicle (AUV). The latter offers the potential for low-cost long-term monitoring deployments but battery life and data collection and transmission constraints are still significant. Biological methods of emission detection are still in their infancy and reliable, practical methods have yet to be developed.

- Natural variation is a key issue for shallow monitoring and properly characterised baseline datasets are essential to capture naturally-occurring spatial and temporal variation. In this regard stationary monitoring systems deployed on the seabed via landers have the potential for tracking time dependent changes over periods of several months or more.
- Assessment of the results from both the operational (predominantly deep-focussed) and research (predominantly shallow-focussed) monitoring activities from Sleipner and Snøhvit indicates that many elements of the new European storage requirements have been met at these large-scale sites.

Knowledge Gaps

Deep-focussed monitoring relies heavily on established hydrocarbon industry tools which are mature. There is scope for improving some of these technologies and related data processing and interpretation for CO_2 storage. R&D priorities for seismics include:

- Better understanding of how seismics can discriminate between changes

in pressure and saturation.

- Improvements in hardware (spatial positioning, data transmission, sensitivity, sensors, real-time recording, improved seismic sources, sensor reliability in passive mode).
- Improvements in data processing and analysis (improved imaging, visualisation, integrated interpretation, and joint inversion).
- Improved shallow imaging (e.g. by further development of the P-Cable system).
- Robust communication systems for permanent systems (so the data are available in real time).
- Low-cost monitoring systems such as seismic interferometry using both passive and active sources are being tested in a variety of settings but are far from proven.
- Continued improvement in the emerging area of fibre-optics.
- The quantification of CO_2 within a reservoir still remains a challenge. The detection and quantification of leakage also remains a technical challenge.

Improvements in other methods include seabottom gravimetry, downhole logging to identify fluid saturation. The development of wellbore monitoring tools to test wellbore integrity would be beneficial. Downhole fluid sampling is not advanced for offshore deployment.

Shallow-focussed monitoring is less advanced compared with deep focused monitoring. AUV technology capable of long-range deployment needs to be developed so that the AUV can be tracked transmit data via a satellite communications system. Real-time data retrieval and navigation will enable onshore operators to modify or refine surveys without costly intervention using a survey vessel. Further development in integrated in situ sensors has been underway over the last five years. An integrated approach to the powering, communications and data management of developed sensors is being pioneered by the active sharing of knowledge by the research groups engaged in this field, which combine academic groups with sensor development companies to enable commercialisation. Trawler proofing subsea sensors to protect them from damage remains a risk.

Model development of marine systems is required to improve their predictive capabilities. Advances are needed so that systems can simulate leakage in the context of natural variability by combing both pelagic and benthic dispersion and chemistry, including carbonate and redox processes. There is also a need to develop models that can simulate large scale dispersion of multi-phase plumes whilst simultaneously simulating tidally-induced dispersion in the near- and far-field. The development of dispersion models is a potential topic for the environmental network which meets in September 2015 at the National Oceanography Centre (NOC) in Southampton, UK. The NOC, for example, has 3D general circulation models (GCMs) that can provide a realistic representation of ocean physics.

Recommendations

- A review should be commissioned by IEAGHG on the requirements for monitoring large surface areas at high sensitivity including cost-effectiveness and complementary benefits of different monitoring techniques. It should also review the effectiveness of monitoring techniques to adequately detect and monitor secondary accumulations at shallower depths. These techniques could be used to detect gas chimneys and help to distinguish the origin of natural seeps. An example of research in this field from the Gulf of Mexico was presented at a combined monitoring and modelling network meeting in August 2014, but research for similar applications in other regions like the North Sea would be beneficial.
- Future monitoring network meetings need to present and review the development or emergent technologies that are under development or have been tested in an offshore environment. The use of natural submarine seeps could provide a useful test bed for monitoring research.
- Review examples of natural CO_2 migration along or across faults and fractures that extend to the seabed in an IEAGHG study.

2015-04 CRITERIA OF FAULT GEOMECHANICAL STABILITY DURING PRESSURE BUILD-UP

Key Messages

- Faults typically consist of two sub-structures: a fault core; and a wider fault damage zone. Faults in low porosity rocks tend to have a fine-grained fault core whereas faults in coarse-grained, high porosity rocks, usually have low porosity deformation bands that can develop into high permeable slip surfaces.
- Fault zone permeability increases with increasing fluid pressure but permeability varies both across and along faults. Hydraulic properties also vary between the damage zone and the core where gouge material is concentrated. This concentration of fine grained minerals also reduces the mechanical strength of faults.
- Mechanical failure or reactivation occurs either when shear stress exceeds normal strength or when hydraulic fracturing is induced.
- Fault deformation can be either brittle or ductile. The former leads to the formation of cataclastite (fine grained granular) and shear fractures which dilate under low effective normal stress that can cause permeability enhancement. With increasing shear deformation, fracture asperities are sheared off leading to gouge production and a reduction in permeability. Thus, in brittle deformation permeability will generally increase under low effective stresses and small displacements but decreases with increasing effective stress and magnitude of displacement. Shear fractures created in ductile deformation contract during shearing and tend not to lead to an increase in permeability.
- Reactivation of faults can be assessed using both analytical and numerical approaches, but assessment is usually based on the Mohr-Coulomb failure criterion. This method can be used to determine the critical injection pressure.
- Numerical modelling can provide predictions of fault stability at different scales and incorporate different parameters such as the geometry of different faults. Numerical methods can be effective for identifying leakage potential and seal failure especially where dilatancy and stress dependent permeability changes occur.

- Experimental tests on minerals and rock samples exposed to CO_2 tentatively indicate that the coefficient of friction is not radically changed, however, this conclusion is based on limited exposure to CO_2.
- There is limited observational data on stress regimes and direct pore pressure measurements from core samples from cap rocks and fault zones. Acquisition of key data would enhance stress regime modelling and fault behavior.

Background to the Study

The storage of CO_2 in geological reservoirs requires relatively permeable conditions bounded by very low permeable layers. Reservoirs can be bounded by faults that can act as seals if, for example, an impermeable formation is juxtaposed against it. The presence of faults in virtually all geological formations is a key consideration as their stability is crucial for the integrity of storage sites. Fault stability is affected by multiple factors including fault structure, material properties, geochemical reactions between CO_2 and fault gouges and pore pressure changes. Injection operation and pressurization of reservoirs usually changes the state of the in-situ stresses which may cause destabilization of previously stable faults. Instability occurs in the form of slip along pre-existing fault or fracture systems, which may be associated with seismicity. In addition, movement along fault planes, and the generation of factures, may create open conduits that breach the integrity of the storage site. Understanding how faults might respond to stress conditions caused by CO_2 injection is therefore fundamental.

Recent geomechanical studies for CO_2 geological storage have focused on initialising stresses in the overburden based on all available geological and well engineering data, modelling the impact of fluid/gas pressure build up on stresses in the storage formations, the caprock and the overburden in general. The challenge is to predict the acceptable overpressure before shear failure, or reactivation of a fault/natural fracture occurs. The prediction process begins by using a verified geomechanical model to calculate the effective normal stresses and shear stresses occurring along all the faults/fractures. These stresses are evaluated in the context of fault cohesion and sliding friction to predict the pre-injection state of stress on these features and to determine the critical fluid/gas pressure required to initiate shear failure on what may have previously been a stable fault/fracture. Stress and

fault properties can vary in space and time.

Scope of work

This report highlights the key factors affecting fault stability and reviews the methodologies generally used to evaluate geomechanical stability of faults during CO_2 storage. It focuses on fault structure, hydro-mechanical properties of fault planes and the methodologies generally employed to assess fault stability. The objective of the report is to provide an overview of conditions that affect faults and highlight the essential components affecting mechanical stability of faults due to CO_2 injection and pressure build-up in reservoirs.

Findings of the Study

Faulting is the response of brittle material to a stress field that exceeds its strength threshold. Faults nucleate from micro-fractures or deformation bands in a critically stressed region and accumulate strain over time to grow. As faults extend, they can interact with neighbouring faults of various sizes and can form special features important in the context of CO_2 storage. A fault zone typically consists of two sub-structures: the fault core; and the fault damage zone. The fault core generally comprises gouge material, crushed particles/cataclasite or ultracataclasite (or combination of the two). The damage zone typically contains fractures at different scales. Faults in low porosity rocks have a fine-grained fault core surrounded by a fracture dominated damage zone. Faults in coarse-grained, high porosity rocks, usually have low porosity deformation bands that develop into high permeable slip surfaces (see Figure 1 on page 67).

Leakage through faults is a function of the permeability of the fault zone. The fault zone permeability increases with increasing fluid pressure towards a critical threshold. However, fault permeability varies both across and along faults. The hydraulic properties of fault cores and damage zones can be quite different as exemplified in Figure 2 (see page 68). These differences are attributed mainly to the properties of fault gouge material. The gouges are either granular or clay-rich. The permeability of granular material depends on the grain size distribution and sorting of grains. The permeability of clay-rich gouges is a function of the type of clay, clay percentage, and its distribution. The deformation along the fault zone also reduces the strength of the fault

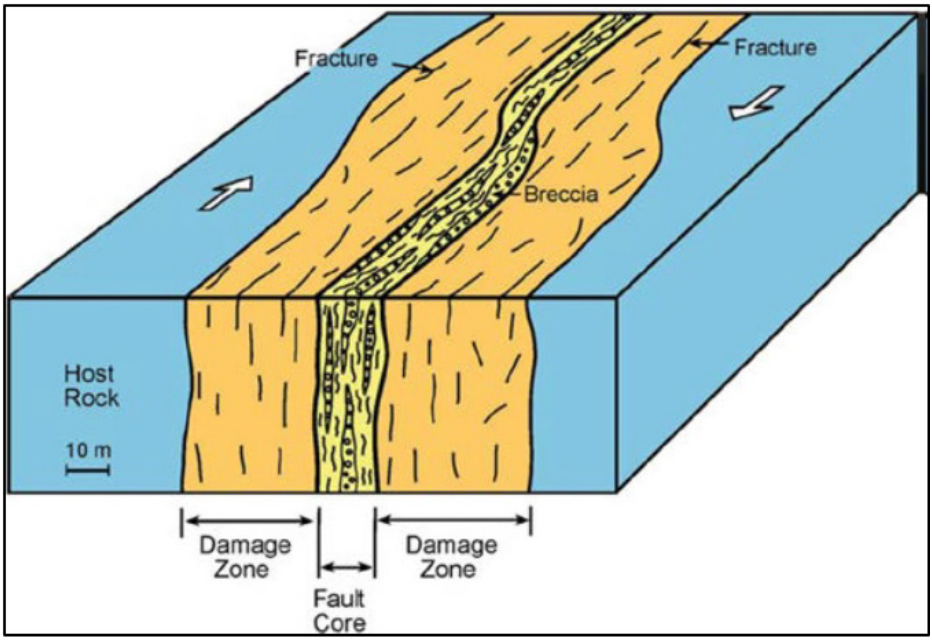

Figure 1, Schematic representation of a fault zone comprised of a fault core and damage zones in a strike-slip fault

core material due to the concentration of clay minerals and micro fractures in the fault core.

Faults are usually the weak links in the rock mass and control hydraulic and mechanical behaviour of surrounding rock bodies. Mechanical failure or reactivation of faults may occur either: when shear stress exceeds shear strength of fault zone material; or when hydraulic fracturing (in case of cohesive faults) takes place. Under these conditions pore pressure exceeds the sum of the minimum in-situ stress and tensile strength of the fault. In the case of shearing, post failure deformation may be brittle or ductile, depending on the shear strength properties of the fault core and the level of the effective confining stress. In the brittle regime, deformation is associated with dilation which can contribute to the enhancement of permeability under low shear conditions, but as shear deformation increases, fracture asperities are sheared off leading to gouge production and a reduction in permeability. Ductile deformation may not significantly change permeability.

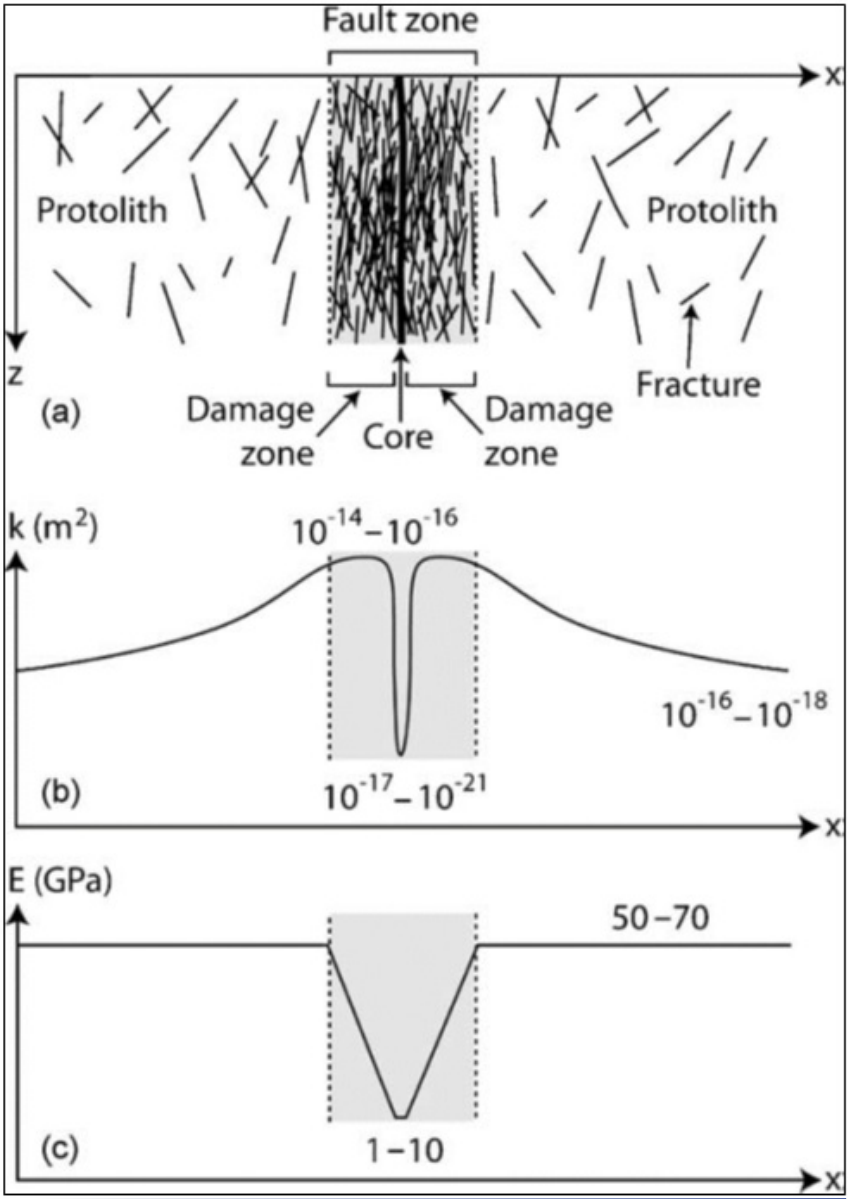

Figure 2, Permeability and mechanical properties of fault zone material

Reactivation of faults and fracture systems can be assessed using analytical and numerical approaches. The analytical approach considers static normal and shear stresses on a fault plane and relies on the Mohr-Coulomb failure criterion to evaluate stability of the fault. By applying this method the critical injection pressure can be calculated from the difference between the current stress state and the predicted failure envelope. The critical injection pressure, also called the maximum sustainable pressure, can be calculated for all possible fault orientations at given in-situ conditions.

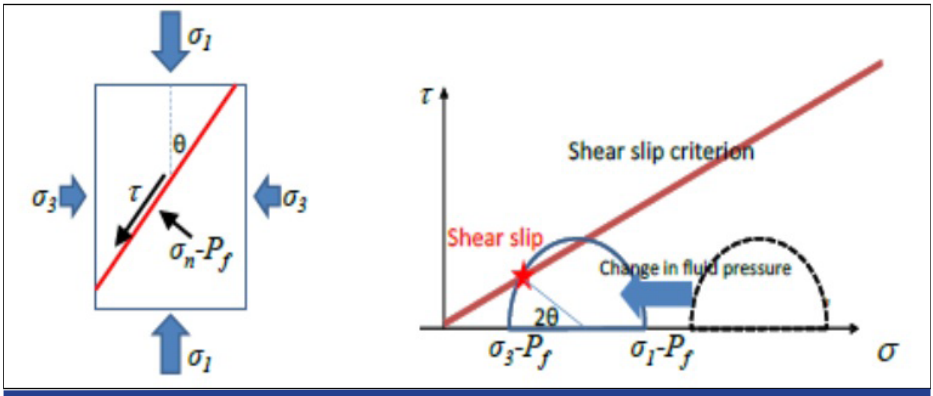

Figure 3, Schematic representation of stress fields on a fault plane and a representation of a change in effective stress due to injection (Mohr diagram) where τ = sheer stress, σ= normal stress, θ = dip angle of fault and Pf is the pore pressure

The critical pressure along faults within a reservoir can be calculated and then plotted on a polar stereographic projection to determine the predominant orientation of faults with susceptibility to shear (least stable).

An analytical approach is a simple and valuable tool for preliminary assessment of fault reactivation potential during injection or depletion. The analytical approach requires the following essential components:

- Magnitude and direction of in-situ stress
- Fault orientation (dip and strike)
- Shear strength, especially friction coefficient
- Initial pore pressure and pressure change

The limitation of this approach is that it is based on many assumptions and simplifications and may not necessarily capture complex physical processes that occur in the reservoir during injection. The stability of faults in the cap rock and overburden as well as reservoirs is crucial for storage reservoir integrity. Consequently fault stability analysis needs to apply to faults within the storage unit and the surrounding formations. The analysis should include the ability to predict the extent of reactivation into the caprock. This may require local modelling of faults in the interface region which could be difficult to capture with variable pore pressures and lithologies. Analytical approaches may be further limited by changes in the magnitude and direction of principal stress directions during repressurisation. These limitations may be overcome by using numerical tools.

Numerical analyses of fault stability can provide fault simulations at different scales and within different geological constraints. Faults can be presented in a global model as single discontinuities, e.g. as a zero-thickness element, in order to explore their general behaviour. If a fault is prone to instability, and the detailed behaviour of the fault zone is of interest, it may be modelled as a rock mass of continuum material. This may require a local model where detailed properties and geometry of the fault zone are assigned to the components of the model. Furthermore, post-failure behaviour of faults is important for determining the potential for fault leakage and seal failure which can be studied using numerical methods where dilatancy and stress dependent permeability are taken into account.

Following preliminary analysis a refined geomechanical model may be necessary. To progress to this more advanced stage a series of parameters will be required including:

- A geometrical description of the reservoir and surrounding rock formations
- Mechanical properties of reservoir and surrounding formations
- Spatial distribution of pore pressure stresses and temperature usually acquired from core and log data
- Loading conditions (time history of a pore pressure field during injection)

To build a more comprehensive model of fault behaviour and the potential for reactivation three main geomechanical components need to be determined:

- In-situ stresses (vertical (σv), maximum horizontal (σHmax) and minimum horizontal (σHmin)),
- Fault zone strength
- Pore pressure profile

To determine in-situ stresses real data on formation geomechanical properties are required. Different techniques can be used to measure or infer the direction and magnitude of in-situ stresses. Horizontal in-situ stresses can be determined from borehole caliper logs, borehole image logs and televiewers. Vertical stress can be inferred from the depth of the overburden. Density measurements can be made from core samples and calculated from density and sonic logs. Determining horizontal stresses is more challenging by comparison. Leak-Off tests, formation integrity tests and minifrac tests can be used to assess the minimum in-situ stress. The maximum horizontal stress can be deduced from hydraulic fracture tests, however values recorded from deep cased wellbores can be very uncertain. If exact stress values are not available they can be estimated using the Stress polygon method which is based on the frictional strength of faults. The upper bound of horizontal stresses can be determined by plotting the limits of fault stability in the form of a stress polygon (Figure 4).

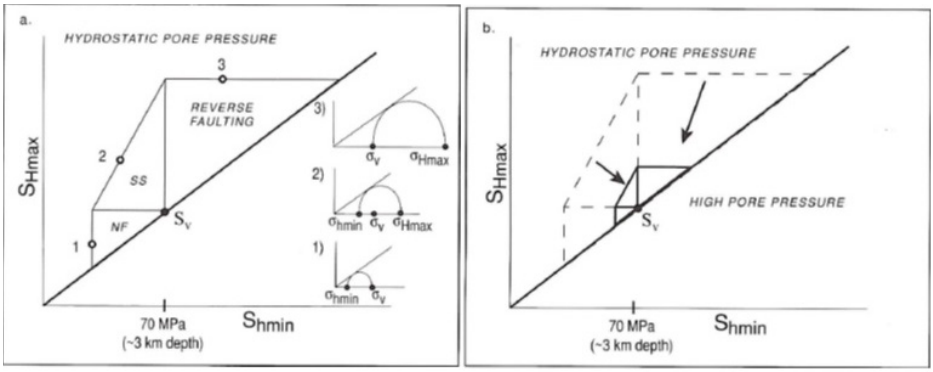

Figure 4, Stress polygon method used to define ranges of stress magnitudes at a specific depth.

A key component that needs to be included in any fault slip or reactivation scenario is the strength and friction coefficient of faults. The strength of faults (τ) can be calculated as a function of depth provided the correct value of friction coefficient (μ) and pore pressure (P) for the fault plane are known:

$$\tau = \mu(\sigma n - P)$$

Data from laboratory tests and field observations show that friction coefficient of faults generally varies between 0.6 and 0.85, although values as low as 0.2 have also been reported in the literature for clay material. The strength of faults in a CO_2 storage reservoir may be affected by the presence of CO_2 but not substantially. A few studies tentatively indicate that the coefficient of friction of the fault-filling minerals does not change pre- and post-CO_2 treatment. This observation is, however, based on a few laboratory studies where the effects of CO_2 on rocks and minerals was only performed over short time spans.

Experimental work has shown that the presence of water decreases friction in cap rocks but not necessarily reservoir sandstones. An investigation into the effects of carbonic acid on carbonate reservoir rock indicated that there was a reduction in the frictional and tensile strength of the lithology which can be inferred from the Mohr circles and failure envelop for pre- and post-CO_2 treated carbonate illustrated in Figure 5 (overleaf). Another test using supercritical CO_2 on the frictional behaviour of simulated anhydrite fault gouge revealed that the friction coefficient of the material at 0.65 and 80°C can be reduced to 0.55 with an increase in temperature to 150°C.

Expert Review Comments

There was a general consensus that the information compiled in the report provides a useful perspective on the subject. It is also complemented effectively by figures and tables. The report offers a comprehensive review of the subject and provides valuable information to companies or organisations who lack familiarity in fault development and associated analytical techniques. However, the study does not increase the level of knowledge for companies that have a strong geotechnical background.

One of the main criticisms of the report was the poor grammar and inaccurate use of references. The initial draft required substantial editing. Occasional

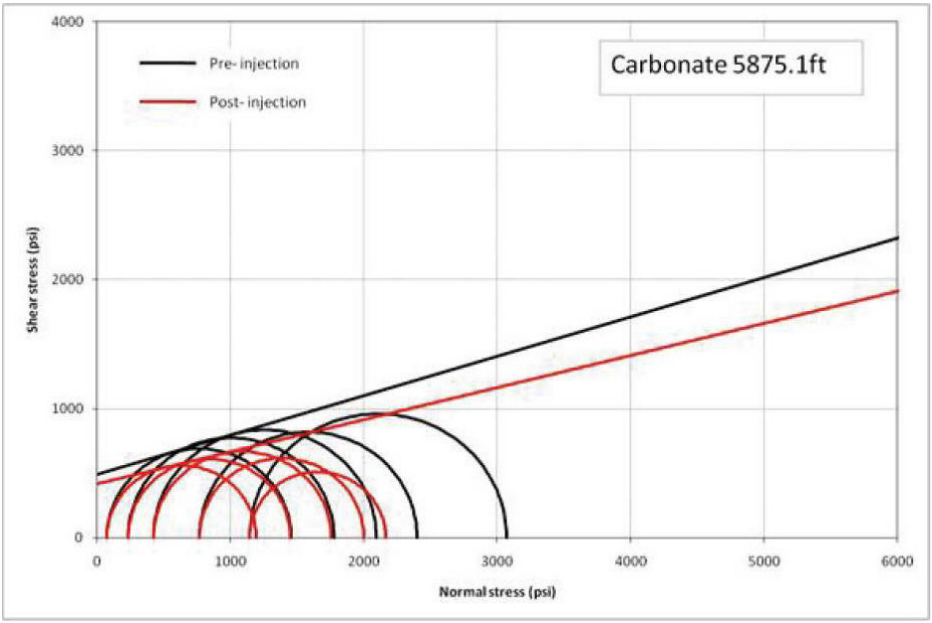

Figure 5, Failure envelop for pre- and post-CO_2 treated carbonate

clarification of technical terminology was also needed. The reviewers thought that the report contained useful references but these could have been more extensive and, for example, included more work published in SPE journals. Some figure captions also required modification and in some cases more detailed explanations.

One reviewer commented that the report was very detailed in some parts particularly the sections dealing with faulting and fault properties. However, it lacked detail on standard oil industry practice.

One concluding remark proposed that a more detailed follow-on study is now required to provide confidence for site operators and stakeholders. A future study needs to explain when faults remain stable and when reactivation might occur, and under what conditions.

Conclusions

- Fault zone permeability depends on the type of deformation (brittle or ductile) and lithology (mineral composition).

- Fault zone permeability increases with increasing fluid pressure. Hydraulic properties vary between the core and the damage zone.
- Mechanical failure or reactivation occurs either when shear stress exceeds normal shear strength or when hydraulic fracturing is induced.
- The Mohr-Coulomb failure criterion can be used to determine shear strength and critical injection pressure but its application is limited by the pattern of stress regimes near faults and changes during depletion / injection. As an analytical method it can only be applied to reservoir formations because of the contrast in cap rock lithology and pore pressure regime.
- Numerical methods can be effective for identifying leakage potential and seal failure especially where dilatancy and stress dependent permeability changes occur.
- Experimental tests on minerals and rock samples exposed to CO_2 tentatively indicate that the coefficient of friction is not radically changed, however, this conclusion is based on limited exposure to CO_2.
- There is limited observational data on stress regimes and direct pore pressure measurements from core samples from cap rocks and fault zones.

In summary, the Mohr-Coulomb failure criterion is the major technique employed to determine stress-strength relationships and stability analysis of faults. It can be applied to assess fault stability during and after injection of fluids such as CO_2, or depletion of hydrocarbons. Analytical methods combined with the numerical solutions provide the best approach for assessing geomechanical stability of faults. Modelling can be used to determine the relative stability of different faults in reservoirs subject to repressurisation and the pressure thresholds required to maintain fault stability.

Knowledge Gaps

The study has highlighted a number of knowledge gaps in the understanding of fault stability analysis:

- Faults within reservoirs are generally well characterised in terms of stress regime and orientation but there is less detail on fault properties that transect cap rocks and extend into the overburden. Changes to

mechanical and hydraulic properties of faults that extent into cap rocks and the overburden, that become reactivated during and post CO_2 injection, are not fully understood.

- In-situ stresses on a fault in a sealing formation may be different from those within a reservoir because of pore pressure differences. Insitu tests, such as leak-off tests or laboratory measurements from core samples, would be ideal but are rarely obtained because historically sealing formations have been of limited interest.
- Geomechanical modelling of faults requires detailed data on fault properties however detailed core samples of fault material are usually limited and the geometry is not necessarily known. This can lead to uncertainties in modelling results. Better calibration is necessary to develop constitutive models to predict various failure modes caused during fault reactivation.
- Fault stability and movement is strongly dependent on pore pressure. The pattern of pore pressure change within fault zones is not usually known. The CO_2 entry pressure into a fault zone might differ compared with the overburden. More detailed knowledge of pore pressure distribution between permeable and less-permeable formations, including fault zones, would improve modelling and reduce uncertainty.
- Relatively few studies have been completed on the influence of CO_2 on the frictional properties of different rock types. Longer exposure times, under experimental conditions, might provide more representative results.
- Observations from oil and gas reservoirs have revealed that the same stress path during depletion is not followed during repressurisation. This phenomenon is important for estimating reservoir compaction/expansion, surface movement and identification of minimum pore pressure required to cause fault reactivation.

2015-01 MONITORING NETWORK AND MODELLING NETWORK – COMBINED MEETING
Theme: Reducing Uncertainty – the application and effectiveness of Monitoring and Modelling

An IEAGHG meeting, hosted by the National Research Center for Coal and Energy, West Virginia University

Session 1 - Welcome

Welcome from National Research Center for Coal and Energy, West Virginia University. Richard Bajura, Director NRCCE & Tim Dixon, IEAGHG

A combined Modelling and Monitoring network meeting, organised jointly between IEAGHG and the National Research Center for Coal and Energy (NRCCE), was held between 5th - 7th August 2014. The meeting was held in the Erickson Alumni Center of the West Virginia University in the town of Morgantown about 80 miles south of Pittsburgh. The meeting brought over 60 delegates from eight countries including Australia, Canada, France, Germany, Japan as well as the UK and USA. The three day meeting focussed on the theme of "Reducing uncertainty - the application and effectiveness of monitoring and modelling".

The meeting was opened by Richard Bajura the Director of the NRCCE. Richard highlighted the importance of energy related research at the centre especially its connection with coal. He acknowledged the support from the sponsors West Virginia Division of Energy, Battelle and the Southern States Energy Board as well as NRCCE. Richard also thank Trina Wafle, the NRCCE Communications Director for West Virginia University, for the excellent organization of the venue and events.

Session 2 – Detection and Monitoring of Migration and Leakage – Chair: Curt Oldenburg

Near Surface Gas Monitoring at the CO_2 Field Lab. Norway, Dave Jones, BGS

The objective of this project is to test near surface monitoring of CO_2 during a controlled release experiment. By monitoring released CO_2 the sensitivity of monitoring systems could be determined. Data could then be used to test and calibrate migration models under controlled conditions enabling results to be up-scaled to full-scale storage sites. The results can also be used to develop a monitoring protocol. Although this is a near-surface (<20m

controlled release) deeper (100m – 300m) releases are planned.

The selected location is a thick sequence of fluvio-glacial deposits at a sand and gravel extraction site in Southern Norway. These sediments are highly heterogeneous, poorly sorted and characterised by a complex bedding structure although they are permeable. During the early stages of monitoring it became evident that high concentrations of CO_2 had reached the surface but in an area offset laterally from the expected area above the release point. Leakage then developed further still from the release point and this continued after injection had ceased. Flux chamber measurements showed pulses of seepage with flow temporarily impeded by heavy rain. By analysing all the monitoring data it was evident that the released CO_2 followed complex migration paths from the injection point to the surface that also varied with time. This pattern of migration is similar to natural seepage sites. A significant proportion of CO_2 was also dissolved in ground water.

The monitoring methods were highly successful in detecting the CO_2 but somewhat less successful in quantifying the leakage. One of the main implications that can be drawn from this release experiment is that even under controlled conditions, uncertainty about migration pathways is large. Monitoring approaches that can deal with this uncertainty are needed. Obtaining a longer period of baseline measurements and longer post injection monitoring would have been beneficial.

The use of Tracers to Validate CO_2 Migration Paths and Rates. Linda Stalker, National Geosequestration Laboratory (via WebEx)

Tracers are widely used in different geological environments to track fluid migration. There are three complementary approaches which are all necessary to understand the mobility of tracers in natural systems. Laboratory experiments can be used to evaluate the suitability of a tracer for a particular system. Field trials can reveal how tracers interact with natural systems. Finally modelling can be an effective method for interpreting tracers but it is reliant on accurate data.

The type of tracer can vary quite widely. For example at Otway CD4, SF6, Kr, and R-134a (SF6 substitute) have been used. Perfluorocarbons (PFCs) and noble gases were used at the Frio Brine Pilot. Other organic and inorganic compounds have also been tested. The quantity of tracer used is governed

by the percentage detection rate that is required. Both field and laboratory methods are used to analyse tracers depending on the composition of the tracer. Some tracer compounds can linger or have memory effects (i.e. retained within the analytical equipment). Other considerations such as the composition of formation fluid and the concentration also need to be taken into account. Tracers in combination with other measurements (e.g., CO_2 content) can give long term information on the behaviour of the storage interval.

Perfluorocarbons dominate in CO_2 storage site assessments and are proposed for measurement of leakage rates. There is potential for development of improved chemical tracers, for example esters. Esters are added to the system where they hydrolyse to form an acid and an alcohol. The detection of three compounds (that includes residual ester) can then be used as tracers. It is possible to determine the extent of CO_2 retention using this technique. By measuring the daughter products that have been produced from the hydrolysis reaction, and the timing of the breakthrough, the degree of residual saturation of CO_2 can be deduced.

The Use of Isotopes to Track Migration and Retention: A Long-Term Perspective. Mark Wilkinson, University of Edinburgh (via WebEx)

The St John's Dome area of the Colorado Plateau in eastern Utah has a number of CO_2 rich natural springs sourced from natural CO_2 reservoirs. The presence of carbonate travertine deposits across this area shows that natural CO_2 leakage has occurred over the last 500,000 years. There are other gases in these systems which can be used as tracers providing evidence of natural migration over timescales of 10,000s to 100,000s of years. Isotopes ratios have been used to determine the origin of CO_2 in this region and how the fluids migrated to the surface.

The δ18O isotope and the δD isotope ratios reveal compositions of water that originate from two different aquifers connected to the surface by a fault. There is genuine variation between different springs making it is possible to differentiate and measure the contribution from each aquifer. However δ13C ratios are too similar to be able to distinguish the C source in this instance.

The presence of Noble gases can help to distinguish where CO_2 might originate from. 3He is derived predominantly from the mantle. The ratio of

CO_2 / δ3He can be used to distinguish the origin of CO_2. The ratio data from the Crystal Geyser suggests it is derived from the upper aquifer and is not of mantle origin. Only 5% of the He sampled from this source is of mantle origin, but the origin of CO_2 is harder to identify partly because of the degree of natural variability (84 – 99% is of crustal origin). There is clear evidence from surface water samples that there has been mixing between the deeper aquifers and ground water.

Carbon isotopes can also be used to demonstrate retention on a geological timescale. The δ13C ratio was measured from calcite precipitated in a caprock and a reservoir beneath it. There are two distinct sample populations, one representative of the caprock and one from the reservoir. One interpretation of the observed pattern is slow migration from the reservoir into the caprock to a depth of ~10m over a period of 50 – 60 M years.

Discussion – Session 2

In natural settings data availability can be a challenge. Firstly, there needs to be a good understanding of the geological environment and the migration paths into and within aquifers. Even if there is a combination of groundwater chemistry and isotope analyses available it is unlikely that a commercial operator would find collection and interpretation of the significant amounts of data needed to interpret the complex natural system and response to leakage cost-effective. Another perspective is to improve the interpretation from limited data.

In cases where artificial tracers are used there is a question of whether they will reach the surface and whether the CO_2 flux at the surface can be quantified. Firstly using stable compounds such as SF6 and PFCs at least to show if tracers work. The choice of tracer should depend on the objective, for instance can they provide high value information about CO_2 retention and residual saturation. It is also advisable to use tracer detection and analysis in combination with modelling. The bigger challenge will be to up-scale monitoring and modelled scenarios to larger systems.

δ14C has been proposed as a 'silver bullet' tracer. This isotope is concentrated in the atmosphere, from which it is absorbed during photosynthesis and therefore its presence indicates carbon of relatively recent origin given that it has a half-life of 5,700 years. It is absent in almost all fossil fuel carbon and

so there is a clear distinction between geologically stored and near surface biogenic CO_2. δ14C has been advocated by some researchers for example at Decatur.

In the Norwegian controlled release experiment, there was an initial expectation that there would be a relatively simple migration path. The model had to be modified to account for the high degree of heterogeneity within the sediments. In retrospect it might have been better to have completed a more detailed site characterisation before injection to gain a more comprehensive picture of the site. However, pre-injection disturbance might have compromised the experimental release.

The CO_2 field lab experience has highlighted the merits of different monitoring techniques available for use at an industrial scale site. Survey methods that can accurately cover a wide area but can also detect seepage from small areas probably do not exist. A limitation of any mobile technique is the height above ground that a detector is mounted. The greater the height above ground the greater the atmospheric dispersion of CO_2 and therefore the lower likelihood of detecting seepage. One possible solution that was discussed was to begin with a reconnaissance technique that can pick up emissions across a wide area. Once an anomaly is suspected more conventional static measurement techniques could be employed to confirm this and obtain more accurate emission rates over a longer period.

Session 3 Detection and Quantification of Leakage – Chair: Katherine Romanak

What Monitoring Techniques are Appropriate and Effective for Detecting CO_2 Migration in Groundwater: Isotope-Based Monitoring. Philippe Négrel, BRGM

Isotopes can be effective for monitoring CO_2 migration, but the approach and selection of the isotope needs to consider a number of factors including the capacity of the isotope detection tools to track CO_2 leakage and how modelling can be integrated with isotope tracking.

Geochemical tracers using the δ13C, δ18O and δD of the water molecule are potentially capable of recording the changes in water quality as a result of the presence of CO_2. Stable isotope studies have been used to investigate the effects of CO_2 on formation water. For example the relationship between the concentration of CO_2 and the impact on δ18O in water and linking carbonate

dissolution to δ13C. A CO_2-water-glauconite interaction has showed how the presence of CO_2 can be linked to the dissolution of glauconite. Boron isotopes (δ11B) were used as a tracer in a laboratory experiment to discriminate between surface reaction and dissolution mechanisms. Dissolution affects the mineral composition which can be traced by comparing glauconite samples that have been subjected to CO_2 - water leaching and CO_2 free water. As the experiment is progressed the δ11B becomes more negative with time as the boron isotopes become more fractionated.

Sr and Li isotope systematics have confirmed the role of glauconite in the interaction with fluids under CO_2 pressure. The key question is the efficiency of these isotope tools in a less constrained system and whether they would be robust tracers at larger scale. To address this question the same set of isotope systematics in the CO_2 field lab experience (Norwegian controlled release experiment) were explored. The multi-isotopic approach (O–, H–, S-, B-, Sr and Li-isotope ratios) converges toward a complex superposition of geochemical processes, and each isotope systematic deciphers different processes, i.e. the mixing of different salinities, interaction between saline- or fresh water and rock, and the interaction between CO_2, water and rock.

According to laboratory experiments and site experience to date, further improvements in detection methods and understanding of geochemical modelling for early detection of CO_2 leakage are needed for complex cases. Improved understanding is also required of the system dynamics at large-scale. The adaptation and testing of isotope tools for site-specific conditions, and defining their capability to track CO_2 migration at greater distances from the CO_2 injection sites, is also required.

Methods for Detecting and Quantifying Leakage Emissions of Carbon Dioxide and Methane using Atmospheric Measurements at Fixed Locations. David Etheridge, CSIRO/CO2CRC

Monitoring the atmosphere near CO_2 storage sites is essential for regulatory, carbon accounting and public assurance purposes. Accurate verification of CO_2 storage is needed. Atmospheric techniques can be continuous, automated, non-invasive and economic. However it is essential to be able to differentiate between any real emissions and background especially because there can be large natural variations. Previous studies have estimated that the maximum tolerable leakage from a CO_2 storage site should be 0.01% per

year equivalent to 1,000 tonnes CO_2 per 10 Mt CO_2 stored. This can lead to a relatively small signal in the atmosphere compared to natural variations unless the detection point is very close to the emissions source.

The CSIRO/CO2CRC team have been monitoring atmospheric CO_2 and CH_4 at the Otway test site which included a controlled release. Emissions from coal mines near Emerald in Queensland have also been monitored by the Arcturus monitoring site (originally established for CCS). The Otway site is in an agricultural area dominated by pasture which is characterised by strong diurnal variations in the natural background CO_2 and CH_4. Differences in CO_2 concentrations and fluxes over a period of four years are attributed to climatic conditions. The team have attempted different techniques to distinguish between natural fluxes and released samples. All these techniques can only provide approximations. By selecting specific conditions of the wind direction, dispersion, ecosystem flux (often using simple parameters such as shortwave (solar) radiation) the background variations can be significantly reduced and leakage signals can be more clearly distinguished.

Ideally a multi point network is needed around the site. However a technique of pseudo upwind monitoring at the Otway site, with a single monitoring point, is another technique that has been used to remove the impact of natural variations. Comparison of (wind speed and direction) in two flanking sectors either side of the sample point, downwind of the release point, can reveal an anomaly that corresponds to small leakage rates. Once detected, follow up monitoring from a number of points and with additional measurements such as isotopes and tracers can confirm, attribute and quantify emissions.

FutureGen 2.0: An Overview of the Monitoring Approach and Leak Detection Capabilities. Alain Bonneville, PNNL

This is the first Class VI Underground Injection Control (UIC) draft permit issued by the US Environmental Protection Agency (EPA). The monitoring programme is designed to verify that CO_2 has been effectively stored and that the total CO_2 mass has been accounted for in the evaluation. The programme includes both direct and indirect methods and will concentrate on the first permeable interval, the Ironton Sandstone, above the primary reservoir, the Mt Simon Sandstone. The lower most aquifer that supplies an Underground Source of Drinking Water (USDW) will also be continuously monitored.

Direct pressure measurements in monitoring wells and indirect geophysical techniques (passive seismic; time-lapse gravity surveys as well as integrated deformation monitoring using GPS and InSAR) will be used to monitor CO_2 plume and pressure-front migrations.

Assuming a scenario with a breach of the caprock, the model is designed to simulate 1% leakage of the total CO_2 injected (22 M tonnes) over three different time periods: 20, 100 and 500 years. Both CO_2 and brine simulated leakage cases are considered. Modelling results show that the CO_2 would be confined to the Ironton sandstone formation. What this modelling reveals is that the CO_2 pressure increases the total pressure slightly above the fluid pressure within some areas of the formation. Moreover the pressure response is detectable up to 1,000 ft (305 m) from the CO_2 plume. The most permeable section within the Ironton formation, where CO_2 is most likely to spread laterally, would be the optimum place to detect changes within the formation. Detailed characterization of the Ironton Formation at the FutureGen2 storage site will be performed to determine the best vertical location and screen length for the early detection monitoring wells. The monitoring plan could be adapted to track the CO_2 if monitoring revealed a change in the anticipated movement of the CO_2.

What Could Controlled Releases do Better? Lee Spangler, Energy Research Institute, Big Sky Carbon Sequestration Partnership (BSCSP), Zero Emission Research & Technology Collaborative (ZERT), Montana State University

There are several controlled release sites around the world including ASGARD (Nottingham, UK), ZERT (Montana State), Ginninderra (Australia), Norway (CO_2 Lab), Ressacada (Brazil). There are also several natural analogues where CO_2 emissions into the biosphere have been studied. While a great deal has been learned from both controlled releases and natural analogs, there are some gaps. There are, however, a number of features of controlled releases which need to be scrutinised. These include:

- In a controlled release experiment the detection limits can be established and the location and flux of the source is known, but there is typically very little overburden.
- Natural analogues typically involve more overburden, but the fluxes, energies and source properties and leakage pathways may not necessarily be similar to a leak in an engineered storage system.

- An understanding of the behavoir and the ability to detect a CO_2 flow pattern through the overburden is a gap.

To put release rates into perspective a 0.001% leakage rate from a 4 M tonne / year point source (equivalent to a 500 MWe power plant) is approximately six tonnes CO_2 per day.

Some of the challenges that controlled release experiments can posed are exemplified by the Montana State University field trial. This is a controlled release from a horizontal tube with six release zones installed below the level of top soil. Stress induced changes to the vegetation are evident from monitoring changes caused by CO_2 concentrations above background levels. The effects of CO_2 are clearly evident in this instance because of suppressed plant growth along the line of the release site. At this site modelling showed that the released CO_2 spread laterally when it encountered a low permeability zone beneath ground level. Some plants in this area have deep tap routes of over 1 m that penetrate the low permeable zone and act as channels for the released CO_2. This example shows that the ecosystem, transport properties and heterogeneity of soils and unconsolidated sediments need to be taken into account.

The experience at the ZERT site, and experience elsewhere, has shown that controlled release experiments need to take account of diurnal, seasonal, and annual variations in ecosystem background flux as they all affect detection limits. Natural analogues also seem to have "patchy" or irregular surface patterns. Measurable changes in aqueous geochemistry can occur quickly depending on soil type and affect CO_2 concentrations.

While most technologies deployed could detect CO_2, what should be deployed at storage sites will be dependent on site properties and the purpose of monitoring. If it is primarily health, safety and environmental or resource protection, monitoring the resource to be protected is obvious. Public assurance may require a different deployment. Verification and accounting can present a challenge for near surface techniques because of the lack of information about transport processes in the overburden and how those processes affect flux and horizontal displacement.

In the future more lessons can be drawn from controlled release experiments.

Deeper releases to understand CO_2 behaviour in the overburden, and the development of detection technologies that could be effective in this region, is perhaps the most important target.

CO_2 Leakage Detection: A Comparison of Groundwater Sampling and Pressure Monitoring. Elizabeth Keating, LANL

Leakage pathways in the overburden may be complex and hard to predict. It is also unclear how extensive groundwater plumes could be and whether sampling-based monitoring would be able to detect a plume. It is possible that pressure monitoring could be more effective. It is also possible that False Negative situations could occur whereby monitoring simply fails to detect any change or False Positive conditions where changes are detected but are unrelated to a CO_2 or brine leak. A probabilistic approach to this risk assessment has been applied which uses a large number of multi-phase reactive transport simulations. The model simulation revealed that the probability of detecting a leak was low. Moreover, the change in pressure was even smaller than the CO_2 footprint, but it may be easier to detect.

Modelling can provide a probability of leak detection depending on the distance from injection. One simulation revealed that there could be a 50% chance that leak detection could be missed 400 m from the leak and only a 10% chance of detection for a given density of wells in the example tested.

Pressure monitoring could offer a more effective alternative. Although pressure monitoring is unlikely to be effective in a shallow aquifer, it could indicate changes within a storage reservoir. Modelling development is continuing and will lead to the generation of leakage detectability maps in reservoirs and overlying aquifers. Further refinement will include discriminant analysis to determine which scenarios could result in fault rupture.

Discussion – Session 3

It is clear from environmental monitoring at different sites that different approaches are required for detection at the surface and in reservoirs. Although a pressure response might be an indication of a leak a rupture along a fault might be gradual so a pressure response may not be that obvious. The reliance on this technique may not necessarily work at every location but it would be useful to know under what conditions it could work. It could be tested at existing demonstration sites, for example Cranfield.

The distribution and spacing of different monitoring points needs to be selective especially if large-scale storage was developed at several sites. Experience at Otway showed that with refinement it is possible to adapt monitoring so that genuine changes can be detected and distinguished from background variations. Detection limits need to be appropriate for the area and the sensitivity of the technology. Natural fluxes at some sites, for example Otway, are very large irrespective of other influences. Consequently, there is a need to take account of different site activities to quantify all CO_2 sources. However, surface monitoring, and the development of more sophisticated techniques, is necessary to satisfy public assurance and puts land owners at ease.

To date there has been a focus on surface monitoring, but there are also plans for holding deeper detection trials, for example at a Canadian site in Alberta which has planned releases at depths of 200m and 700m. BGS and the University of Nottingham are also looking at a deeper injection test in the UK.

Session 4 Offshore – Chair: Tim Dixon

QICS – A Controlled Sub-Seafloor CO_2 Release Experiment – An Overview of the Scientific Results. Ian Wright, National Oceanography Centre, UK

QICS is a controlled release experiment to gain an understanding of the environmental disturbance, parameter sensitivity and the persistence of low-flux leakage. The release site was in a bay just north of Oban on the west coast of Scotland. The CO_2 was delivered via a pipe drilled through bed rock to a release point below the unconsolidated sediments above the bed rock. By Day 2 (D2) there was seismic evidence that a gas chimney began to develop. The chimney had extended by D12 through the fine grain mud sediments but not the sand layer. As time progressed the plume migrated laterally at the sand / mud interface. By D34 the gas had formed a chimney in the overlying sand. Bubbles were detected using acoustic sensors at a distance of up to 100 m and diver observation. Most of the released CO_2 remained in the sediments and dissolved in the pore water. The changes to the pore water chemistry proved to be the most sensitive indicator of the presence of CO_2.

There are several features of CO_2 plumes in sea water which need to be considered. The plumes are initially buoyant, but following rapid dissolution the plume becomes denser than the surrounding sea water and sinks.

Currents and tidal mixing also rapidly disperse the plume. Stratification and sea floor topography can also retain CO_2.

The Monitoring Programme in Tomakomai CCS Demonstration Project. Daiji Tanase, Japan CCS Co.

A monitoring programme is being developed for the Tomakomai demonstration project, off the Japanese island of Hokkaido. The project, under the direction of the Japan CCS company, will target two different formations by drilling two separate deviated wells from the shore. The highest reservoir is in the Moebetsu Sandstone Formation between a depth of 1,100 and 1,200m. The second reservoir is in the T1 Member of the Takinoue Formation which is a volcanic lithology between 2,400 and 3,000m. There is a possibility that mineralisation could occur when CO_2 is injected. There is a substantial section of mudstone caprock above this formation extending to the base of the Moebetsu Formation which is also sealed by caprock. Three onshore observation wells will also be installed onshore. A single vertical well will be drilled for the Moebetsu Formation and a deviated well, plus a vertical well, will be drilled for the Takinoue Formation. In addition an ocean bottom cable (OBC) and four Ocean Bottom Seismometers (OBSs) will be deployed on the sea floor above the test site. The OBC, OBSs, three observation wells and one other onshore sensor, will monitor microseismicity and natural earthquake activity. The baseline monitoring is planned for 2015.

The marine environmental monitoring will include physical, chemical and biological parameters. Seawater chemistry, micro biota will be sampled as well as sea floor sediments. Benthos will be collected and observed by divers or an ROV. Tidal currents and direction will also be measured. The baseline monitoring including a seabed side-scan sonar and a sub-bottom profiler survey was completed by 2014.

Differentiation Between Natural Processes and Induced Leakage in an Offshore Environment. Bio-Oceanographic Approach to CO_2 Leakage Detection. Jun Kita, Research Institute of Innovative Technology for the Earth (RITE)

The background to this study is the necessity to monitor CO_2 offshore in case there is a CO_2 leak into seawater. The Japanese Prevention of Marine Pollution and Maritime Disaster Act stipulates that the operator must monitor and test seawater quality and report results to the regulatory authority. It is

also important to be able to differentiate between any exogenous signal and natural background variability.

Photosynthesis by marine algae naturally oxygenates the water column and reduces the CO_2 content, but degradation, particularly within seabed sediments, causes O_2 consumption, a reduction in pH and an increase in CO_2. There are both annual and diurnal fluctuations in the CO_2 concentration. RITE have conducted a case study using published data collected by a profiling system in Ise Bay off the east coast of Honshu. A suite of water quality parameters were analysed including temperature, salinity, dissolved oxygen (DO) and pH from the surface to the sea floor. The Total CO_2 (TCO_2) and the Partial Pressure of CO_2 (pCO_2) can be calculated if the relationship between salinity and total alkalinity are known. There is a strong negative correlation between TCO_2 and DO. TCO_2 values that exceed the 95% predicted confidence interval are statistically above natural background variability and leakage is suspected.

Overburden Imaging using High-Resolution 3D Seismic: Perspectives from 3 Surveys in the Gulf of Mexico using P-Cable Technology. Tip Meckel, BEG, University of Texas

The objective for this study was to refine the capacity estimates for CO_2 storage in Miocene age sediments off the coast of Texas. The project set out to evaluate regional containment potential with capacities up to 30 M tonnes. Seal integrity and the presence of structural compartmentalisation formed part of this evaluation. A 10 mile wide inshore swath under the Texas state regulatory control was characterized using available integrated conventional seismic, well logs, paleontological 'picks', focusing on the most prospective sand-prone intervals of the Miocene age stratigraphy. Additional high-resolution 3D seismic data were acquired using P-Cable technology above prospective storage sites to investigate fault extent and fluid flow processes in the overburden.

Information about the active hydrocarbon system was used to inform understanding of capacity and seal quality for CCS. Natural gas accumulations with equivalent CO_2 replacement of ~30 M tonne capacities are comparatively rare, suggesting that there may be geological limitations to trap integrity. Alternatively, field sizes may be limited by naturally charged hydrocarbon volumes (under-filled structures). An area of particular interest was adjacent

to a shallow salt dome, close to the shore, that has a number of dry wells associated with it. This condition indicated that hydrocarbons either did not accumulate, or could have leaked out. Such a site might still be a suitable CO_2 storage site at a shallower depth.

Conventional seismic at lower frequency is not good for imaging shallower sediments (shallowest hundreds of meters of stratigraphy). P-cable seismic surveys utilize closely spaced short streamers that allow processing at small spatial resolution (6.25 m bins) and have high frequency content (150 Hz) at shallow depths. Fluid migration can be detected utilizing such high-resolution systems, often exceeding the ability to make similar determinations from conventional seismic data. Using higher frequency (150 hz), as compared with conventional seismic at (25 hz), it is possible to enhance vertical resolution down to 2.5 m. This new survey has revealed complex geological structures around a salt dome and it has been possible to detect thin fluvial channels plus faults which extend to the sea floor which would be missed at lower resolution. The evidence from this detailed survey has revealed that the seal has been offset and possibly breached. Chimney structures can also be detected which could mean a compromised storage prospect. The migration processes that have given rise to this phenomenon now need to be understood. The documentation of complex stratigraphy and structures in the overburden is important for appreciating the complexity that may accompany vertically migrating fluids, but the imaging of a gas chimney provides a sense that such technologies could be used in a time-lapse mode (similar to Sleipner) for monitoring for leakage at CCS sites.

Snøhvit CO_2 Storage and Monitoring: Update and Latest Monitoring Results. Bård Osdal and Philip Ringrose, Statoil

Under Norwegian carbon emissions legislation CO_2 from a natural gas field needs to be re-injected. The Snøhvit field is the world's first subsea CO_2 injection project. Produced gas is piped to an island close to the Norwegian mainland where there is a separation plant. The purified CO_2 stream is then piped back to the field and re-injected. Initially CO_2 was injected into the Tubåen Formation, but the pressure build up led to a decision to switch to the stratigraphically higher Stø Formation. Seismic interpretation of the Tubåen Formation revealed that its reservoir properties were governed by a fluvial deltaic system that preferentially channelled the CO_2 in a sandstone

unit limited by shale barriers causing a pressure build up. Faulting may have also contributed to confining the CO_2 and increasing pressure. In contrast the Stø Formation is a shallow marine formation with good lateral and vertical reservoir properties. By using a reservoir simulation, and continuous history matching using 4D seismic, it has been possible to check the progress of the plume. The exercise has shown that seismic can be used as an effective pressure monitoring tool. Interpretation of seismic enabled the pressure regime to be accurately predicted which was confirmed by later down-hole tests. Pressure and temperature is continuously monitored and shut-in tests are also conducted to check reservoir pressure. Pressure monitoring has subsequently shown that there has been a stable pressure profile, but with a gradual decline possibly due to hydraulic communication with an adjacent fault block. In the very long-term the CO_2 accumulation could eventually migrate across or around the faults into the next structural block and into a producing gas field leading to its contamination with CO_2. A new injection well is planned for 2015 to minimise the risk of contamination.

Discussion – Session 4

The benefits of being able to conduct seismic surveys to improve the resolution of geological features over a broad depth range is now possible as well as the potential for the greater use of microseismic monitoring.

The cost of P-cable for a survey area of 30 – 40 km^2 costs approximately US$700,000, however this is cheaper than an onshore seismic survey covering a comparable area. Onshore seismic might also be useful for providing data on reservoir pressure conditions. The P-cable survey has demonstrated the ability to investigate comparatively shallower formations which are of interest for CO_2 storage. Broadband seismic can enable seismic surveys to be conducted over shallow and deep formations. Improvements in seismic will help to distinguish features such as heterogeneity and faults and aid in the interpretation of changes that have occurred in geological systems through time. Offshore microseismic monitoring is currently too expensive but its application could emerge especially for detecting changes in the proximity of faults. Advances in technology, for example fibre optic cable, might enable microseismic to be deployed offshore. Direct pressure monitoring is another technique of key importance for determining reservoir conditions.

Monitoring: Conclusions and Recommendations – Chair: Sue Hovorka and Tim Dixon

The monitoring topics covered a variety of different techniques both on and offshore. Controlled releases could be tested faster over shorter time periods to observe the main effects. However, more gas is likely to escape. In contrast, a slow leak might lead to complete dissolution. The depth of an aquifer will also influence the degree of dissolution. QICS could give the impression that CO2 migration through unconsolidated sediments is very rapid, but this may not necessarily reflect what would happen if CO_2 migrated through a thick column (~km+) of unconsolidated sediment such as in the Gulf of Mexico. Natural seeps suggest much slower rates of migration. There is also the question of how much CO_2 is trapped in the pore fluid. Hydrate formation is possible in shallow sediments below 9°C. The lithology will ultimately determine the rate of migration (which could take up to 10 million years).

Research of natural CO_2 seeps can provide comparative analogues. Analysis of noble gas isotopes that are associated with CO_2 has been used to distinguish its origin (for example from two different sources). Recent research is also highlighting the use of a variety of different isotopes to investigate water-rock and dissolved CO_2- rock interaction. Measurement of different isotopes, in formation fluids and within mineral lattices, can potentially show whether CO_2 migration has occurred.

Monitoring methods are implemented for a variety of reasons, for example, operational and assurance aspects. The benefits of monitoring include developing experience and expertise, improvements in risk based approaches and cost effectiveness.

General Conclusions

- Observation of in-zone reservoir pressure could be an effective technique for the detection of induced fault leakage
- Offshore seismic monitoring may be more cost effective for characterization and monitoring than onshore for similar survey sizes.
- Tracers are most useful in combination (i.e. a cocktail) and have shown good results for residual saturation (containment).
- The first two Class VI permits have been issued in the USA by the EPA for FutureGen 2 and Decatur.

- Storage monitoring of CO_2-EOR is different from saline storage
- Microseismic monitoring is generating benefits - data from current projects is identifying and reducing uncertainty
- Monitoring to modelling iteration is essential and proving effective

The gaps identified from the meeting drew attention to the following issues:

- Surface monitoring for leak detection – what are the requirements for monitoring large areas at high sensitivity?
- Will injected tracers make it to the surface?
- How can fracture zones and related migration mechanisms and processes be effectively monitored?
- Can secondary accumulations at shallower depths be adequately detected and monitored?
- Baselines for CO_2-EOR projects are difficult to define.
- There is a need for (shallow) monitoring techniques which are continuous, real time, accurate, and cost effective. There are problems with accuracy of available sensors and effective benchmarking of available sensors.
- Monitoring for commercial-scale deployment: what will be the right balance between cost and accuracy to meet regulatory requirements.

The meeting proposed the following recommendations

- More work on faults and fractures – attract people working in this area
- Leakage detection out of reservoirs
- Quantification and mass balance of stored CO_2

Session 5 Long-term predictability – Chair: Rajesh Pawar

Review of Different Regulatory Frameworks and how they have Dealt with Long-Term Predictability. Anna Korre, Imperial College, London

There are a plethora of international, EU, USA, Australian and Canadian regulations that deal with long-term predictability.

There is considerable variation in the degree of prescription stipulated by these regulations. The requirements vary between two main themes: (a) whether the monitored CO_2 plume is behaving as expected compared to

model predictions to; (b) the absence of detected leakage. Some regulations state that the CO_2 plume must be stable or evolving towards stability. Other regulations state that there must be no environmental impacts, integrity of injection wells and integrity of wells within the area of impact.

To meet these requirements a combination of monitoring, modelling and risk assessment activities need to be implemented. All regulations have a requirement for a plan that needs to be submitted for approval before a project can proceed. Particular modelling or monitoring techniques are not necessary but specifying the outcomes of risk assessments is a requirement. The 'OSPAR FRAM' provides an excellent basis for modelling and risk assessment.

Liability referred to in regulations is not clear. The term 'responsibility' is also used to refer to 'liability' in regulations. After liability has been transferred, the state/competent authority may continue to monitor the site. The 'IEA model regulatory framework' contains a clause that the operator should also provide suggestions for monitoring the site after liability transfer. Some regulations also contain a mechanism which enables operators to contribute to a collective fund to cover costs after liability has been transferred. The 'EU directive 2009/31/EC' requires further monitoring after liability transfer as a backup measure, while other regulations (e.g. 'EPA UIC') do not. Despite this difference both require safety to be shown before liability transfer.

Why do Long-Term Processes Matter? – An Introduction Based on the ULTIMATE-CO_2 project. Jeremy Rohmer, BRGM

Public perception of long-term processes over scales of 1,000s of years is usually negative. Improving the certainty of long-term processes is therefore important. The life of a CO_2 storage project is long term, but there are several issues which fall under this designation: the end of injection; the end of monitoring; and closure of the site. The long-term physical aspects include the disappearance of free CO_2 and the establishment of a steady state regime. This needs to cover hydrological, chemical and mechanical stability process which could extend over 100s, 1,000s or even 10,000s of years. The classic concept of CO_2 entrapment is a combination of stratigraphic and structural trapping, residual trapping, solubility trapping and mineral trapping. The relative timing of each of these processes, and the dominance of each of them, is subject to uncertainty. Numerical modelling can help to predict

long-term conditions, but models require calibration from field data which is not necessarily available. Model realisations are also a simplification of reality. The approach of different models might be valid but they can have widely divergent solutions.

Wellbore sealing integrity in the Opalinus clay is being tested at the Mont-Terri facility in Switzerland. CO_2 fluid is being circulated between the cemented wellbore and the formation to observe changes in permeability. Provisional evidence shows that permeability is decreasing possibly due to carbonation reactions.

Natural analogous are often proposed as examples of potential long-term conditions that might apply to CO_2 storage sites. They can show how CO_2 reacts with different formations over timescales of 1,000s of years. However, the degree of relevance is open to question. The burial history, hydrology and the role of CO_2 in diagenesis might be quite different. CO_2 migration in a natural system might take place over millions of years.

The Role of Glaciation and its Implications for Monitoring and Modelling of CO_2 Emissions: the Case of the North Sea Basin. Tom Bradwell, BGS

Glaciation affects CO_2 storage beneath the North Sea and has a strong influence on seal integrity. Glacigenic deposits have significant discontinuities and heterogeneities and can reach thicknesses of up to 1 km in the North Sea Basin. Successive glaciations have had a significant geomechanical impact due to loading and unloading cycles, and hydraulic pressurisation.

Glacial sediments are very diverse and tend to be highly heterogeneous. Glacio-tectonic processes have created widespread, often highly pervasive, discontinuities plus folding and faulting from micro (~mm) to macro (~km) scale. Across the North Sea Basin, glaciation has also created tunnel valleys and channels, on a large scale, as well as 'chimneys' and other vertical porous bodies on a smaller scale. The interconnected, branching morphology of these channels as well as their highly variable sediment composition, makes it difficult to model consistent fluid flow properties. These features can be buried or exposed and can contain over-pressurised pore fluids, due to glacial loading. Pockmarks are also evident. These features are associated with underlying fluid migration routes or 'chimneys' created by shallow gas. All these structures potentially provide fluid migration pathways from underlying formations.

Ice sheets on the magnitude of the northern European Quaternary glaciations have exerted massive loading forces on the underlying formations in the North Sea Basin during the last 2 million years. During ice sheet loading and unloading, stress can propagate to depths of >50 km directly affecting the porosity and permeability properties of the subsurface. Experimental work shows that horizontal stresses remain elevated even 10,000 years after ice retreat. The dynamic changes to the stress regime could disrupt faults and fractures long after the ice sheets have melted. There is growing evidence of post-glacial neo-tectonic activity in Scandinavia which could be related to ice sheet retreat.

Modelling has been applied to the North Sea Basin to estimate the impact of ice sheet loading. This modelling shows that it can take 15,000 years after glaciation for the underlying formations to return to a 100,000 year old former stress regime. Reverse hysteresis shows that stress field paths are not exactly reversed during glaciation-deglaciation (loading-unloading) cycles. The modelling also indicates permanently increased horizontal stress loading. The stress regime around the edges of the ice sheet is likely to experience the greatest change and will, therefore, be more susceptible to subsurface disruption and potential fluid migration.

Long-term Monitoring Strategy and Modelling Assessment for Underground Radioactive Waste Repository. Guillaume Hermand, ANDRA

ANDRA, the French Radioactive Waste Management Agency, is developing a long-term repository for intermediate long lived and high level radioactive wastes. The facility must have an operational safety limit of 120 years and long-term safety in terms of containment of 1 million years. The agency is currently characterising a suitable site within the Meuse/Haute-Marne region of eastern France. The host formation is a Callovo-Oxfordian clay between two low permeable carbonate formations. In addition to low permeability, the region is tectonically stable, with a very shallow dip of 1.5° and few faults with limited displacement. Physical processes including thermal, hydric, mechanical (THM) and radionuclide diffusion, as well as the coupling of these processes, are being simulated to evaluate long term safety. Simulations of these physical processes (with and without coupling) are integrated with geological data, gained by in situ measurements and geophysical modelling

of the strata, enable long term safety to be evaluated. An underground laboratory has been has been built to evaluate construction methods and overall design.

Modelling needs to simulate changes that may occur over a 1 million year period. For instance, due to the exothermic packages there will be a thermal transient over the first 120 years which will diminish with time. The models need to simulate how the primary containment changes and then the conditions and containment properties of the host clay formation over thousands of years.

A monitoring programme has been designed to ensure that the repository will remain safe during waste package installation as well as after disposal. Surveillance is also necessary for operational security and nuclear safety. Monitoring is also designed to meet the requirement for retrieval and long term safety. Because of the demanding conditions imposed by temperature, pressure, chemistry and irradiation, the sensors' hardening needs to be developed and tested. High levels of redundancy need to be built into the instrumentation. The probability of an unplanned occurrence, the seriousness of an anomaly, and the ability to detect an event before it happens, all need to be taken into account. Research and development currently includes the development of fibre optic sensors, sensor metrology, sensor hardening, wireless transmission systems, data mining and decision making.

Discussion – Session 5

The effects of glaciation, and the requirements for radioactive waste repositories, bring a different perspective to long-term processes. The permeability of shale formations is of interest to any form of long-term storage where containment is a primary requisite. Estimates of permeability (for gas in a dissolved phase) are of the order of 10-18m2 (10-3 mD).

The question of whether monitoring techniques have sufficient resolution to meet the requirements of carbon cap and trade schemes was raised. Monitoring techniques are designed for detecting changes and history matching comparisons with models. It is not clear whether they would be suitable for cap and trade verification.

The nature and timing of glaciation across the North Sea Basin has yet to be resolved. The pattern of glacial episodes, their duration, the thickness of ice

and the resultant loading in the central North Sea Basin all need considerable further refinement.

The discovery of a seabed fracture (the Hugin Fracture) has been erroneously linked to the Sleipner field. The feature is related to a glacial tunnel valley 200m deep which has created flow paths for biogenic CH_4. There are also pock marks in several areas which are associated with natural fluxes and seeps of biogenic origin. It is clear that glacial processes contribute to the complexity of the overburden across parts of the North Sea. The impact of glaciation on the stress fields of potential storage reservoirs was raised. The Goldeneye area, as an example, has been subjected to several glaciations, however, production of gas is testimony to the field's 55M year containment. Shell have undertaken extensive testing of Goldeneye (at a depth of 2.5 km) to measure its stress field. As a depleted gas field the reservoir has undergone depressurization. Once it begins to be repressurised it will be important to understand how the pre-existing stress fields acting on faults and other structures might change. The experience from Sleipner has demonstrated how important it is to characterise the whole overburden to avoid any confusion between processes within the reservoir and unrelated processes at shallower depths.

Natural seeps from oil and gas reservoirs are evident but on geological timescales and generally much longer than the ~10,000 year time span for CO_2 storage integrity. Stress fields acting on reservoirs are important but Quaternary deposits also act as seals. Long term storage integrity for potential storage sites north of latitude 30°N need to consider the impact of glaciation on hydrological and tectonic processes.

Session 6 Heterogeneity and Up-Scaling Capacity Models – Chair: Philip Ringrose

Defining Model Complexity: What Level of Model Sophistication is Required and When? Rajesh Pawar, LANL

One way to simulate an entire system from reservoir to shallow aquifers is the application of reduced-order models (ROMs). Development of ROMs requires a series of multiple simulations of detailed component models for reservoirs, wellbores, faults and aquifers. Validity has to be tested by applying sensitivity analyses of key variables based on field or lab data. ROMs can then be linked via integrated assessment models (IAMs) to predict system performance

and risk. ROMs can capture complex processes but remain computationally efficient.

The ROM approach can, for example, be used to predict the time-dependent leakage rate of CO_2 and brine through a cemented wellbore. In this case the ROM has to take account of CO_2 saturation and pressure at the reservoir/wellbore intersection as well as multi-phase flow, phase-change, buoyancy-driven flow, capillary and residual effects. Allowance has to be made of variability in wellbore completions, cement permeability and depth. Similar ROMs have been applied to reservoir simulations and CO_2 leakage into shallow aquifers through time. All these ROMs can be run together to build a picture of how CO_2 migration might occur throughout an entire system, expressed as changes in pH in shallow aquifers. The rate of change relative to variables such as the numbers of wellbores and wellbore condition can be predicted by adapting this approach. The integration of ROMs can produce a prediction of leakage paths and rates and therefore where monitoring should be targeted. Computational efficiency can be achieved by ROMs coupled together to represent an entire system. Probabilistic simulations help to optimise the selection and deployment of monitoring technologies.

Capturing Heterogeneity and its Effects: What are Models Capable of and What are their Limitations – the Upscaling Issue. Emmanuel Mouche, CEA / LSCE

One of the challenges of reservoir models is the ability to capture hydrodynamic complexities created by heterogeneity. This is evident when homogenous effective transport equations are applied to fluid migration in a heterogeneous reservoir. An equation that describes small-scale fluid transport for example advective transport in Darcy velocity fluctuations may not adequately predict larger scale processes such as dispersion i.e. upscaling. There are three key forces that control CO_2 migration: injection; capillary forces; and buoyancy. Two phase models include mathematical expressions for these three mechanisms. Model simulations also need to incorporate functions for differences in permeability between layers. Gravitational flow and capillary pressure will vary between two layers with contrasting permeability. CO_2 saturation pressure will increase at the interface between the two layers until critical saturation has been reached and then the CO_2 will migrate across the interface into the less permeable layer.

During injection and near the injection well gravity is likely to be a second order process. Stratification is negligible and gravity can be treated as a perturbation. Inversely fluid movement either some distance from the well, or after injection has ceased, becomes dominated by gravity. These conditions lead to local stratification under low permeability layers. Gravity solutions may, therefore, provide a better solution but only for areas with low fluxes. When capillary forces become more dominant transport processes become more complex. Models used to predict plume front to and across an interface with different capillary pressures can have errors of up to 30%. Consequently there is a strong requirement for numerical validation of theoretical approaches.

Effects of Heterogeneity on CO_2 Storage in a Saline Reservoir: A Case Study from Nagaoka Pilot-Scale CCS Site in Japan. Takahiro Nakajima, RITE

A small CO_2 storage pilot site at Nagaoka in Niigata Prefecture, Japan has been monitored to test a geological model of the reservoir characterised by heterogeneity. This feature of some sedimentary facies has a strong effect on CO_2 migration which was observed at this site.

At the Nagaoka site, the pressure response was monitored at the injection well and a monitoring well located 60m from the injection well. Between 20 and 40 tonnes of CO_2 were injected per day over a 17 month period between July 2003 and January 2005. A total of 10,400 tonnes of CO_2 was injected over this period. A combination of pressure measurements, CO_2 saturation and cross-well tomography were made between three observation wells drilled between 40m and 120m from the injection point.

Previous 3D seismic imaging was used to reconstruct a profile of the reservoir. Porosity and permeability measurements were deduced from four well logs. These data were then used to build a petrophysical model by applying a Random Function Gaussian Simulation (RFGS). The derived model showed highly heterogeneous distributions of the petrophysical properties. Good matches were achieved when observed pressure and CO_2 saturation were compared with the simulated CO_2 behaviour in the geological model. Monitoring and simulation results suggested that CO_2 continued to migrate up-dip post injection. Further refinements to the model are planned.

Discussion – Session 6

Model development and refinement remains an ongoing challenge. Examples from this session have highlighted the complexities of models which need to incorporate several different parameters.

The validity of models is tested by history matching with observed data. A good example comes from the pilot site at Nagaoka. Conformance match with cross-well tomography between two observation wells (OB2 and OB3) was considered reasonable but not exceptional. In Sleipner shale layers within the reservoir were not thought to be important until seismic showed that these layers did influence CO_2 migration. Another example within the Mt Simon sandstone formation showed that CO_2 migration and pressure transmission was not initially captured in modelling until injection began. In the absence of sufficient detail it may be necessary to upscale to gain an initial understanding of a reservoir before more data can be acquired.

Experience from petroleum reservoir engineering tends to indicate that predicting break through is extraordinary difficult and therefore is it reasonable to expect models to provide accurate predictions. Consequently it is always worthwhile to revisit observed data. Near well observations are considered to be very important for highlighting variability in reservoirs.

The work on theoretical fluid flow properties within formations shows that reservoir simulations neglect capillary forces models built around viscous forces. Current mathematical expressions for capillary and gravity forces do not adequately simulate fluid flow. It is thought that viscous forces within the Sleipner reservoir decay within metres of the injection point. Transitional behaviour from viscous to capillary and gravity are there importance to understand.

The methodology for calibrating reduced order models (ROM) was raised. It should be possible to calibrate simulations of underlying processes for each stage or the entire ROM. As CO_2 leakage from storage sites has not happen there is a lack of evidence available for calibration.

The Sensitivity of Storage Simulations to Pressure Artifacts: Indications from the Sleipner Benchmark. Andrew Cavanagh, Statoil

Pressure artefacts appear to influence CO_2 distribution within Sleipner, but their effects are difficult to simulate. Observations of the Sleipner benchmark

have aided model development and improved predictability. The reservoir model has been designed to simulate the CO_2 plume immediately beneath the caprock. The model was based on Darcy flow which applies viscous forces and assumes vertical equilibrium (VE) reservoir simulation. But this approach resulted in a poor match with the seismic response. A percolating flow approach was then attempted based on capillary forces at basin scale. This model allows gravity separation to occur. This too produced a poor match.

The simulated pressure field for the plume is very shallow; there is a pressure difference of only 250 kPa (35 psi) over 3 km. However, the impression of the shape of the plume, and the estimated pressure field, was inaccurate. Pressure was then allowed to dissipate in the VE reservoir simulation. In this case the plume redistributed to its buoyant equilibrium position and a much better match with seismic observation was achieved. However, this match was based on dissipation over a 100 years which contrasts with the 25 years it has taken for the plume to reach its current distribution and thickness.

A simulation of CO_2 injection shows that 75% of the total CO_2 that is injected is rapidly dissolved but once injection stops, in this case after ~12 years, the rate of dissolution is suppressed. A further 10% dissolves within eight years but it takes a further 50 years before another 10% dissolves and approximately 30 years for the remaining 5% to go into solution.

Some important conclusions can be drawn from this work. Pressure dissipation allows a better match. The Sleipner plume is close to dynamic equilibrium at each stage of its development and is gravity dominated. The projected plume shape, and estimated pressure field, can be attained provided simulations are run over ~100 years. This strongly suggests reservoir simulations for CO_2 storage may be susceptible to significant pressure artefacts that distort model predictions.

The Search for Pathways to Integrate Monitoring in Risk Assessment Based Modelling. Tom Daley, LBNL

Monitoring programmes are designed to aid the development of risk assessments at different stages of projects. Techniques which quantify data can be used for comparative purposes and to ensure regulatory consistency. Standardised methodologies and accepted models are therefore required,

but does this approach reduce risk and uncertainty?

Quantitative seismic monitoring is difficult, for example at Ketzin the mass values estimated differ within 5 – 7% from the actual quantity of injected CO_2. In Sleipner an upper layer CO_2 mass of 50 – 70 kt is considerably less than the estimated 110 kt. These disparities are attributed to the temperature profile, layer thickness and gas saturation.

Monitoring of a small volume of released CO_2 at Frio has provided an example that is analogous to a leak. The release was monitored by time lapse VSP. Two small scale injections: one of 1,600 tonnes; and a later 300 tonne injection proved hard to trace. A measure of time-lapse noise, Normalized Root Mean Squared (NRMS), was used to refine and quantify data quality but the data resolution was too poor. Modelling was seen as a solution to confirm the quantity of injected CO_2. More continuous monitoring is need so that observations can be history matched with reservoir models. This would improve quantification and risk assessment.

The US-DOE National Risk Assessment Program (NRAP) work highlights a need to improve the cost/benefit ratio of monitoring to achieve good quality data that can be integrated with models. A good example is fibre optic seismic sensing which can provide a low-cost option for long term monitoring. The application of multiple tools enhances data quality and interpretation. Continuous data processing can, however, be challenging, because it needs frequent modelling for integration into an overall subsurface model so that different techniques can be compared at variable time and spatial scales.

CO_2 Storage Uncertainty and Risk Assessment for the Post-Injection Period at the Ketzin site. Anna Korre, Imperial College

Ketzin is the first European onshore pilot site for CO_2 storage in a deep saline formation. ~67,300 tonnes of CO_2 was injected between June 2008 and August 2013. The reservoir is situated in the Upper Triassic Stuttgart formation within an anticlinal structure. The reservoir formation is composed of highly heterogeneous fluvial sandy channel facies that alternates with muddy floodplain facies. The 3D distribution of the fluvial channels in the far-field region determines the migration pathways and plume footprint. There are uncertainties in the far-field channel distribution and therefore the pattern of the long-term plume behaviour. Consequently there are implications for

monitoring, verification and risk management.

A binary facies model representing the two different deposition environments was used for the petrophysical model. An E300 model of reservoir parameters (salinity, permeability, pressure) was set up and history matched with well pressure data. The E300 simulation shows plume migration towards the apex of the anticline and settlement against the faults that transect the formation. To predict the pattern of plume migration in the far-field, 25 realisations of channel distributions were generated based on the petrophysical properties of the near-field. Porosity and permeability estimates in the far-field were generated using Sequential Gaussian Simulations. The uncertainties of plume behaviour were quantified by estimating the arrival time, residence time and the maximum amount of free CO_2. Probability maps for free, dissolved and trapped (residual) CO_2 distributions in the top reservoir layer were also produced. The modelling suggest that there could be significant uncertainty in the arrival time of CO_2 and as much as 10,000 tonnes (15% of the total mass injected) could be present as free CO_2.

Discussion – Session 6

The need for large numbers of different realisations, and the frequency of monitoring to validate models or changes in predicted forecasts, were the key points for discussion.

Some projects have generated up to 100 realisations but is this excessive? Experience from site developers shows that there will always be uncertainties and therefore multiple realisations may be necessary to predict the range and pattern of CO_2 plumes. Site developers need to be able to communication key features of storage sites to regulators to justify the adopted approach and explain the variation in site characteristics. It is possible that there is no single answer. Goldeneye is designed so that if the site behaves differently from forecasts changes to the monitoring plan can be made. Similarly the models can provide high and low case scenarios and can be modified in the light of monitored parameters. This approach should ensure that projected forecasts are correct.

A permit requirement can dictate the frequency and granularity of pressure measurements. At Cranfield pressure monitoring was continuous generating large volumes of data. There was a consensus that at least with continuous

data, or regular observations, there is a record which can be analysed especially if there are anomalies that need to be explained. Computer data acquisition and filtration can be used to process data and help with interpretation.

Session 7 Leakage Pathways and Fault Transmissivity – Chair: Jeremy Rohmer

Analysis of Risks and Key Factors Controlling Potential Leakage from Carbon Storage Reservoirs. Christopher Zahasky, Stanford University

Models can provide a semi-analytical assessment and contribute to the risk assessment of storage sites including leakage pathways posed by faults. There are sub-seismic faults, with displacements of <10m, which are not detectable from seismic surveys. Fault characterisation needs to include its width, length, displacement and profile. In this example the base case model assumed a reservoir composed of an Arqov sandstone with a permeability of 28 mD. An injection rate of 7.9 kg/sec equating to 250,000 tonnes per year was assumed. The model included an aquifer with the same permeability immediately above the caprock. The injection point was 500m from the fault. In the base case leakage scenario two driving forces dominate: pressure build up in the reservoir; and buoyancy due to the contrast in density between the CO_2 and formation brine. A sensitivity analysis of different parameters was then applied. Of the nine parameters tested, three were clearly more dominant in terms of inducing leakage: reservoir permeability; fault permeability; and aquifer permeability. This model revealed that the lower the reservoir permeability the higher the leakage rate. In contrast, higher aquifer permeability above the reservoir led to a higher leakage rate.

The evidence from this research suggests reservoir and aquifer transmissivity are as important as fault transmissivity in determining potential CO_2 leakage. Low permeability injection reservoirs pose the highest risk of leakage based on this model.

Modelling Fault Reactivation, Induced Seismicity and Leakage During Underground CO_2 Injection. Jonny Rutqvist, LBNL

Fluid injection into formations were faults and fractures are present can induce seismicity. For example, overpressures due to large-scale fluid injection induced seismic events at the Enhanced Geothermal System in Basel. It is important to determine the potential for structural damage and human perception. The effect of potential fault reactivation caused by

CO_2 brine also needs to be understood as part of any risk assessment. Fault reactivation may change the permeability in faults and possibly compromise the sealing properties of a storage site although this needs to be determined. The size of the caprock/storage aquifer may have a role. Minor faults in close proximity to storage sites need to be carefully evaluated and may not be initially detected.

Two different scenarios have been modelled. Scenario 1 (S1) is a minor fault and Scenario 2 (S2) is representative of a fault with a larger offset. Both faults are dipping 80° and the horizontal stress (normal to the strike of the fault) was assumed to be a factor 0.7 of the vertical stress. Both have the same initial permeability. S1 fault permeability changes by 1 – 2 orders of magnitude as injection progresses up to 100 kg/s. Seismicity of magnitude 2 – 3.5 occurs above a flow rate of > 30 kg/s. The higher the permeability the greater the length of time before an event is triggered and the larger it will be. Leakage does not occur at an injection rate of 20 kg/s, but the model shows that leakage as high as 30% of the flow rate can occur when the injection rate rises to 100 kg/s. In S2 there is higher overpressure compared with S1 but induced seismicity occurs when the fluid flow rate into the reservoir is lower. However, no leakage would occur even under worst case conditions (magnitude ~3.6). A dynamic analysis of S2 shows that fault reactivation would occur at 10 MPa overpressure. There would be a 4 cm slip over 290 m along the length of the fault equivalent to a 2.53 magnitude event.

This model has shown that there is a poor correlation between seismic events and leakage. A single event is not enough to substantially change permeability along the entire fault length. It is clear that site characterization is essential to determine, for example, whether there are multiple caprocks and multiple storage aquifers both of which can reduce the leakage amount and the magnitude of seismic events. The model outputs suggest low potential for structural damage. Shallow-induced events and frequency analysis are well within the proposed limits, although they could be unsettling for the local population.

Discussion – Session 7

The main points made were as follows:

- Modelling fault behaviour could be based on a threshold pressure. In the model developed by Lawrence Berkley reactivation was caused by an

increase in fluid flow over a five year period equivalent to an overpressure of 10 MPa. The model calculated a rupture length of 200m along the fault. Fluid flow along or across the fault, or leakage, does not necessarily occur during seismic events. Under some conditions flow and leakage can occur.

- Conservative assumptions were made in the Lawrence Berkley model to reactivate faults. Deliberately high pressure was assumed and fluid flow was allowed over a 5 year period. The damage zone was treated as solid medium with anisotropic properties including fractures. If induced seismicity occurs there is no substantial change in fault permeability along the entire length of the fault. Maximum events may be estimated (bounded) provided site-specific characteristics are adequately accounted for.
- In Decatur micro-seismic events line up along lineaments but not necessarily faults. Data on faults in argillaceous formations shows that there is a correlation between the clay content and low permeability. Some conductive faults do occur in carbonate reservoirs with Darcy level permeablities but they are not extensive.
- Fault permeability in civil engineering is of key importance especially in dam construction. There could be some useful experience in this industry of relevance to CO_2 storage.

The permeability of faults and the behaviour of fluid movement either across or along fault zones needs to be better understood. The experience of the civil engineering sector especially in dam construction should be investigated to assess its relevance to CO_2 storage.

Session 8 CO_2-EOR and Long-Term Storage – Chair: Tip Meckel

Modelling and Monitoring Associated with CO_2 Storage at the Bell Creek Field (PCOR). Charlie Gorecki, EERC

Bell Creek is a U.S. Department of Energy Regional Carbon Sequestration Partnership (RCSP) project lead by the Plains CO_2 Reduction Partnership (PCOR) studying CO_2 storage associated with a commercial Enhanced Oil Recovery (EOR) project operated by Denbury Onshore LLC. The Bell Creek project utilizes an adaptive management approach combining site characterization, modelling, simulation, risk assessment, and monitoring to demonstrating the technical and economic viability of safe long-term CO_2

storage associated with commercial CO_2 Enhanced Oil Recovery. Injection began in May 2013 and 997,392 tonnes was injected by June 2014. The planned storage capacity is 14 M tonnes. 40 – 50 M barrels of oil will be recovered from the commercial EOR operation.

A numerical simulation model has been created to determine breakthrough times and saturations to update risk assessments and guide the timing and location of effective monitoring strategies. The model is also used to predict storage capacity, sweep efficiency, recovery factor and utilization factor. Good history matches have been achieved for pressure, gas and water production rates. The model predicted first breakthrough at production wells after 3 months of production and 5 months at a dedicated monitoring well. Monitoring revealed CO_2 breakthrough occurred after about 3–4 months. Injected and retained (stored) CO_2 roughly matches predictions after 1 year of injection. Simulation results indicate that by September 2017 at least 1.5 M tons will have been stored in the Bell Creek Field. The amount of CO_2 retained in the Bell Creek field is similar to other EOR operations reported in the literature.

Reservoir Modelling for EOR Associated Storage in Closed Carbonate Reef Oilfields (MRCSP). Neeraj Gupta and Priya Ravi Ganesh, Battelle

Closed carbonate pinnacle reefs across the Michigan Basin form a series of depleted oil fields which are candidates for EOR and CO_2 storage. The Midwestern Regional Carbon Sequestration Partnership (MRCSP) has been actively conducting characterization, modelling, and monitoring of injection activities in multiple fields for CO_2 storage potential in conjunction with EOR. There has been a progressive increase in the amount of CO_2 injected since 1996 when EOR operations started. By 2014 almost 1.4 M tonnes of CO_2 was in-place. Instrumented wells and pipelines in active fields are used to track CO_2 injection and CO_2, brine, and oil production.

One of the highly depleted late-stage EOR fields has been used for more detailed assessment by MRCSP, including injection of more than 240,000 tonnes since 2013. Extensive monitoring has been performed, including pulse neutron logs, pressure, temperature, borehole gravity, vertical seismic profiling, INSAR, and fluid analysis. Reservoir simulations are being used to model the CO_2 injection, pressure response, and plume behavior in the reef across complex phase and compressibility changes. Simulations are

run from initial pressure prior to the supercritical phase to supercritical and eventually to a point when reservoir capacity has been reached. There has been successful history matching with oil and gas production as well as reservoir pressure for the primary production. However, the Black-oil model under predicts reservoir pressure during CO_2 injection. There are two possible reasons: the reservoir boundaries are not accurately modelled; or the CO_2 solubility affects pressure. Refinements have improved predictability. Complex CO_2 phase behavior influences reservoir response and needs to be integrated into the reservoir models. The lessons learned can then be applied for MVA in newly targeted fields for evaluation of EOR and associated incidental CO_2 storage.

Discussion – Session 8

The fate of CH_4 in these storage sites was questioned. CO_2 is the dominant gas phase typically 94 – 96% of the injected gas stream. However, CH_4 is reinjected at both sites (Bell Creek and MRCSP Michigan site). Monitoring complications can arise in these oil and gas fields especially pressure. Pulsed Neutron (PNC) logs are run to determine CO_2 saturation but it can be difficult to differentiate phases (CO_2, CH_4, H_2O). CO_2 monitoring in these fields is also helping to validate the monitoring tools' applicability in different settings. The monitoring programme needs to be adapted as the risk profile changes through the life of the storage site. The first phase could last 10-20 years depending on the rate of recovery and EOR economics. The Weyburn EOR field monitoring was difficult because the EOR function and the presence of different phases.

Both Bell Creek and Michigan Basin site are covered by Class II regulations. Class VI, which is specifically for CO_2 storage, does not apply.

The impact of cyclical pressure on faults is not relevant to the Michigan site as there is no known faulting in the reef. No microseismicity has been observed. The original reservoir pressure declined as the field's oil and gas was depleted. It then increased with CO_2 injection and is currently slightly above discovery pressure. This does not appear to have caused any integrity issues. CO_2 EOR in multiple reefs is possible if they have not been subjected to water flooding.

Modelling: Conclusions and Recommendations – Chair: Philip Ringrose, Andrew Cavanagh and James Craig

A series of conclusions, gaps in knowledge and experience and recommendations were proposed from the modelling topics. The general conclusions that could be drawn included:

Model Complexities, Heterogeneity and Up-scaling

- The definition of long-term is unclear but should it be given a number. The public perception of long-term is usually negative.
- There is a new appreciation of glacial processes on storage integrity. Successive glacial advances and retreats have induced cyclical loading on the underlying formations. Fluvio-glacial processes have created tunnels and other features which act as conduits for escaping fluids.
- CO_2 storage development can learn from radioactive waste experience especially in terms of designing robust and reliable sensor technology.
- The NRAP reduced order model (ROM) concept can be used to assess and link risks associated with storage sites from reservoirs to potential leakage pathways in the overburden, to groundwater contamination and atmospheric emissions. The link to monitoring data and detailed models needs to be validated by applying sensitivity analyses of key variables based on field or lab data. ROMs can capture complex processes but remain computationally efficient.
- History matching is an essential technique for checking the validity of models and refining them so that they provide better predictions. But some phenomena, for example the predicted time for plume migration, can still be difficult to accurately determine. This suggests that some fundamental physics is not clearly understood. The integration of gravity / capillary forces and pressure need further investigation.
- Models are site-specific and need to be tuned to site-specific monitoring data. The modelling and monitoring loop is gradually improving accuracy. The number of realisations that are actually required needs to be called into question. Moreover large volumes of data need to be efficiently processed to produce meaningful results.
- Real site experience from Japan, Norway, Germany and the USA has produced good matches with models but the broader applicability of

these matches needs to be assessed.

Fault Related Issues

- Induced fault leakage may not be as bad as had been previously thought but the question remains on whether fault leakage, or potential leakage, be managed and controlled? Microseismicity may also be minor.
- There is a database of fault properties for oil and gas reservoirs in the literature which has been pulled together and used by operators.
- Some civil engineering aspects, especially related to dam construction, may have relevance to CO_2 storage sites. Fault permeability and risk assessment are of particular interest.
- Slip events are often not large enough to have an impact on whole fault permeability.
- Some experiments show fault slip in clay rich shale lowers fault permeability (range of applicability?)

Long-Term IIssues

- There are more similarities than differences amongst countries' regulatory requirements. Modelling is an essential requirement. In most countries regulations attempt to be prescriptive about what information is needed from models but not what models to select.
- Monitoring needs to be sufficiently accurate to confirm storage security.
- There is still some uncertainty and variability about long-term issues (e.g., liability transfer).
- Glaciation should be accounted for in some environments (Northern Lattitudes).

CO_2-EOR

- One of the key issues for CO_2-EOR projects is the effect of multiple phases (gas) in the reservoir and the ability to monitor CO_2.
- Experience from the USA shows that CO_2-EOR projects start with good reservoir data and history matched models because of previous oil and gas production.
- Is EOR CO_2 storage monitoring significantly different from saline storage?

- There could be a need for different CO_2 storage options. At what point does CO_2-EOR switch from oil recovery to CO_2 storage and how is CO_2 storage efficiency (recycle rate) measured?

The Following Topics were Identified as Gaps:

- There needs to be a better definition for long term.
- Monitoring of CO_2-EOR for storage is a future topic for more detailed discussion.
- The baseline for CO_2-EOR projects is difficult to define.
- Further work to understand fault related leakage.
- Geological modelling of glacial stress changes.
- Improved simulators for gravity- and capillary-dominated flow would improve the understanding of reservoir physics.
- The level of detail in models could be further improved so that heterogeneity is better represented.
- Improvements in solubility / dissolution modelling.

Recommendations:

- Joint network meetings add more value.
- Learning from other industries (mining, dams) would give another perspective.
- Close the loop between monitoring and modelling.

Session 9 Microseismicity: implications for Storage Security – Chair: Don White

Critical Geomechanical Processes in the Overburden. Josh White, LLNL

Geomechanical processes can be challenging to model because the underlying uncertainties are large. Stress uncertainty is one area that is receiving more detailed investigation and the In Salah case is a good example. The storage reservoir is covered by two cap rocks: a 740m main caprock and a lower 210 m unit that overlies the sandstone reservoir. A 4D seismic survey revealed a seismic anomaly that extends ~150m above the reservoir formation. Monitoring indicates that fluids have migrated into part of the lower caprock but there is no indication that the main caprock has been affected. A variety of migration mechanisms have been studied: fault leakage; movement through pre-existing fractures; and hydraulic fracturing.

Despite the specific mechanism, the state of stress is a critical control. The measurement of stress therefore needs careful consideration.

In an example of stress measurements around the Snøhvit field, there is a general north-west maximum stress trend but the stress orientation is variable around the field. In this case regional stress data measured around a field provides a better understanding of uncertainty but it also shows the extent of variability. Taking point samples in a large, 3D volume means that the stress field may not be fully understood.

Understanding the Microseismic Response to CO_2 Injection at CCS Sites – Examples from In Salah. Anna Stork, University of Bristol

Microseismic monitoring of the In Salah CCS site was conducted between 2009 and 2011 using a vertical array in an observation well. Recordings of >9,000 microseismic events from the In Salah field were analysed, revealing two distinct clusters. These are mainly thought to originate from a fracture zone extending NE from the injection point. In this particular case it is difficult to pin point the event locations because data from only one correctly functioning three-component geophone was available. The difference between P and S wave arrival times can be used to estimate the distance to the event. However, errors in the site velocity model could mean events are mislocated. P to S arrivals showed that a very small number of events may be located at a shallower depth than the injection interval but these are not thought indicate CO_2 migration at such shallow depths. Instead, these events are thought to be caused by stress transfer into the overburden. Shear wave splitting, i.e. where a wave is split by an anisotropic medium into fast and slow waves, can be used to determine the fracture orientation and the degree of anisotropy. The dominant orientation of the fracture aligns with the present day maximum stress direction. Detailed scrutiny of the event data has concluded that CO_2 injection induced pressure opening of fractures then close as the pressure falls.

Microseismicity induced by fluid pressure can be used to delineate faults and fractures within storage complexes. Monitoring microseismicity can provide useful real-time information to identify event locations, fracture characteristics and focal mechanisms to understand the seismic and geomechanical response, contributing to the verification of geomechnical models.

Real-time processing is essential for early detection of storage security problems. Microseismicity may be indicative of larger events in future. The technique has demonstrated that it can be a useful tool for monitoring CO_2 and its effects during pressure build.

Connecting Subsurface Seismic Activity to Pumping during Hydraulic Fracturing. William Harbet, University of Pittsburgh, NETL-RUA

The advent of shale gas and shale oil across the United States has led to the widespread use of microseismicity to build a comprehensive understanding of subsurface stress fields. Research applied to hydraulic fracturing of low permeability formations is of relevance to CO_2 storage where it is also important to understand, and predict, the interaction of hydraulic flow with features such as faults and fractures.

Microseismic monitoring from observation wells is being used to determine the position of artificially induced microfractures during shale gas development. The difference in the P and S wave arrival times can be used to identify the origin of microfractures. Data analysis and interpretation of microseismic signals with hydraulic stimulation episode, magnitude, spatial and temporal location, in combination with statistical analysis, can be used to delineate subsurface features. Microseismic monitoring is also an essential tool to characterise the efficiency of stimulation.

Analysis of microseismic data, specifically the frequency-magnitude distribution, can be used to determine the nature of the stress regime and overall failure mechanism. This type of analysis can be used to identify different mechanisms (shear and tensile failure). Shear failure could mean that existing faults are reactivated.

There is another dimension to the study of subsurface microseismicity and fluid injection namely Hydraulic Diffusivity (D). D is defined as the ratio of transmissivity (or hydraulic conductivity) to storativity (or specific storage) of a medium. In terms of hydraulic fracturing it is a comparison of the distance of an event from the injection source to the time of the event since the initiation of injection. Long distances with short time intervals mean high hydraulic diffusivity and visa versa. This approach can be used to identify pressure fronts induced by hydraulic flow which can then be compared with surface pumping pressure, seismic energy and time-distance cross-plots.

Collectively these data can provide a detailed image of subsurface fault and fractures and their response to fluid injection.

Advance data processing that can extract trends from noisy or indistinguishable data, referred to as Ant Tracking, can be used to identify faults and their properties.

History and Interpretation of Microseismic Activity at the Illinois Basin - Decatur Project. Marcia Couëslan, Schlumberger Carbon Services

One of the objectives of the seismic programme is to characterise this formation and the over lying seal the Eau Claire shale. Seismicity is also being used to image the plume development over a three year period. Microseismic events are also being monitored. This extensive seismic programme includes 2D and 3D surface seismic surveys, time-lapse 3D VSPs, and microseismic monitoring arrays. Data has been recorded from May 2010 to November 2011.

Pre-injection microseismic monitoring recorded 68,575 trigger events from multiple sources, but after filtering out noise and industrial activity 7,894 were attributed to storage development operations. Since injection began events of magnitudes from -2.14 to 1.14 have been recorded and form distinct clusters distributed between the Lower Mt. Simon Sandstone, Pre-Mt. Simon Unit and the Precambrian basement.

In 2012, early investigations into the relationship between the microseismic activity and other operational parameters showed that there were often bursts of microseismic activity when the injection well was shut-in. Analysis of the amplitude of the P- and S-wave arrivals was used to try and determine the source mechanisms behind the microseismic events that occurred up to December 2012. A dominant north-east trend was detected and associated with a number of parallel planes with the same orientation. A conjugate plane with a N10W orientation is also evident. These planes roughly align with the dominant horizontal stress directions in the basin. Spatial orientation of observed microseismic events appears to be consistent with the local in-situ stress regime. It is not clear what geological features are associated with the clusters possibly faults or fractures.

Discussion – Session 9

Detailed seismic monitoring is capable of providing an image of the geomechanical properties of different formations (mechanical stratigraphy). There is a general question related to this concept: what would be the ideal conditions for containment that would ensure caprock integrity. Ideally sealing formations need to be stiff and have an inherent stress field that does not favour vertical fracture propagation.

One of the challenges of interpreting microseismic signals is to pin down event locations especially with only limited geophone coverage. Multiple arrays, preferably in down-hole configurations, help to reduce uncertainty and allow seismic events to be tied more accurately to a location. Data needs to be carefully scrutinised. The accuracy of velocity models is particularly important to obtain good event locations. Uncertainty can be reduced by comparing microseismic monitoring results with other data. To understand seismicity and how it links to geomechanical properties of formations, faults and fractures depends on a minimum level of monitoring to detect if and where events occur and how they are related to geological structures.

Session 10 How can Modelling Improve Monitoring Efficiency or Limit Monitoring Costs without Reducing Effectiveness – Chair: Grant Bromhal

Model-Based Monitoring Design for Determining Plume Stabilization: a Proposed Plan for the Citronelle Geometry. Sue Hovorka, BEG, University of Texas

To demonstrate permanent storage, the rate and geometry of stabilization of CO_2 plumes will need to be understood once injection stops. Some jurisdictions require post-closure planning as a condition of the permit. Consequently, the properties that lead to the most uncertainty during post-injection CO_2 migration need to be understood. After closure, the flow physics will be dominated by buoyancy and capillary forces. Viscous forces are no longer dominant because of a decrease in differential pressure and a decrease in flow velocity. Once injection ceases, the significance of vertical anisotropy could increase. Monitoring approaches that are designed to validate closure models are needed. One of the conditions that will need to be avoided is the extension of the plume beyond a specified limit (the wrong imbibition curve).

Models of post-injection conditions will need to be calibrated and validated by geophysical measurements. There may be a regulatory component to modelling and monitoring. Under Class VI rules the owner or operator will need to monitor the site following the cessation of injection to show the position of the CO_2 plume and elevated pressure to demonstrate that USDWs are not being endangered. The rule requires that monitoring will need to be conducted for 50 years but that an approved alternative schedule can be proposed.

Experience from those projects where injection has ceased can provide some indication of plume stability. At Frio stabilisation was attained and there was no CO_2 produced from an injection well. Monitoring of reservoir fluids over time shows that CO_2 has clearly been retained in the reservoir and has not migrated away from the injection well.

A new method for testing the plume stabilization using the injection well itself as a monitoring point was proposed, and the potential for augmenting the sensitivity using tracers emplaced at the end of injection considered.

Probabilistic Geomechanical Analysis of Compartmentalization at the Snøhvit. Josh White, LLNL

The application of modelling to assess uncertainty is evident from a case study of the stress measurements around the Snøhvit field off the coast of northern Norway. The field is fault bounded and has a consistent north-south stress field but there is some rotation from this general trend. An increase in fluid pressure could reactivate faults and create leakage pathways. Sensitivity analyses revealed that the most significant critical uncertainty is SHmax orientation, but that the overall leakage risk is low.

Snøhvit downhole measurements need to be carefully analysed. It can take up to two 2 days to allow time for detection equipment to stabilise due to thermal effects. Corrections also need to be made for temperature before accurate values can be obtained. Several down-hole gauges are necessary to resolve the effects of natural formation parameters (pressure and temperature).

The next stage was the selection of the most appropriate monitoring programme to reduce this uncertainty. Well test analysis and continuous inversion of pressure gauge data was indicative of a partly compartmentalized

system which tied in with impressions from 4D seismic images. Well tests, such as falloff tests, are commonly used to look for flow barriers, such as faults, and other reservoir characteristics. However, such tests require shutting wells in for long periods. Multi-rate injections are also difficult to analyse. One solution to this challenge is a superposition model to characterize reservoirs from calibrated gauge data and standard well test analysis that can then be compared with typical flow conditions observed from other reservoirs. Alternatively gauge data can be used to forecast future pressure conditions and different injection strategies. If overpressure is predicted brine production could be initiated ahead of CO_2 injection to minimize overpressurisation.

Discussion – Session 10

Fluctuations in pressure measurements and the use of data inversion to make forecasts was questioned. In some cases, for example at In Salah, pressure versus flow rate are an indication of fractures within the reservoir. Making forecasts based on data inversion may not necessarily give accurate projections. There are limitations with this approach and the projections should be treated with caution. Experience shows that data acquisition can be substantial so there is a benefit form analytical tools that can provide quick real time responses and therefore input to reservoir management.

The quantification of CO_2 in reservoirs for cap and trade implications, and the value of CO_2 storage, was raised. At Citronelle there has been insufficient injection to image CO_2 in the reservoir but retention has occurred. Cross well logs between the injector and observation wells will be used to image CO_2 at Citronelle, but at a depth 9,400 ft (~2,866m) it is difficult to image the CO_2 in the reservoir from seismic. This situation is one of the motivations for developing monitoring programmes that can validate post-injection stabilization models quickly and effectively.

Session 11 Cost-effectiveness – Chair: Jun Kita

Technical Advances and Cost-Effective Monitoring: Results from a Recent Case Study. Katherine Romanak, BEG, University of Texas

All the components of CCS need to become cost-effective, including the shallow monitoring of storage sites. As CCS and the transition from research and demonstration sites to industrial-scale operations progresses monitoring will need to adapt. A less intense, minimalist approach is likely to become

the norm. There will need to be a balance between regulatory and technical goals; and a balance between cost effectiveness and accurate data collection. Process based monitoring has a number of advantages. The approach uses simple gas ratios (CO_2, CH_4, N_2, O_2) to identify the processes affecting CO_2 in the vadose zone. This means that a leakage signal over background noise can be promptly identified without substantial background measurements. Moreover, the method is not dependent on geologic variability. There are, however, drawbacks. Firstly it is time and labour intensive. Secondly a manned gas chromatograph is required; and thirdly it cannot provide continuous real-time data. The advantage of continuous real-time monitoring is that it can provide a higher degree of assurance especially if a leakage anomaly occurs. This should ensure stakeholders have greater confidence in site integrity and risk management.

Existing industrial sensors have been tested in two field trials. Results indicate that compared with gas chromatograph analyses gas sensors lack sufficient sensitivity. This research clearly highlights the need for new technology capable of reliable and accurate real time detection.

Addressing Cost Uncertainties when Planning and Implementing a Monitoring Programme for a Carbon Storage Site. Claudia Vivalda, Nidia Scientific Services

The use of a probabilistic cost model for a system at its feasibility stage should improve the confidence in the cost estimates and the uncertainty in cost estimations. Probabilistic cost estimates also provide a sound basis for comparisons of alternative monitoring programmes. The approach includes evaluation of costs based on sensitivity analyses.

The development of a cost model begins with probabilistically distributed values for uncertain costs using Monte Carlo simulations. The cost data is then subject to statistical evaluation to provide more reliable and realistic estimates. The results are then analysed to aid decisions. The estimated costs are balanced against other relevant parameters such as safety, performance and maintenance.

A cost model for a specific reference monitoring plan has been tested. Monitoring techniques from this example were grouped into categories. The monitoring plan was based on selected techniques designed for the entire

life-cycle of the site. Uncertainties of different categories are factored into the model. Costs are separated between internal (e.g. injection phase) and external categories (e.g. regulatory requirements). The level of uncertainty is incorporated into the model by varying the length of time for different stages, for example, the injection phase. The results from one probabilistic model scenario showed that the reference total monitoring cost has a certainty of about 60%, and the closure phase cost increase counts for 54.9% of the total monitoring cost.

Discussion – Session 11

The limitations of field sensors, and the discrepancies between measurements made at test sites and in laboratories, is a key theme. The response from instrument manufacturers to the limitations of their products is to apply correction factors. This does not always improve instrument performance in the field. The reason for inconsistency remains unresolved. Moreover, other organisations including the BGS have experienced similar differences between field and laboratory measurements. Even if this was possible retrospective adjustment is not practical if long-term continuous field monitoring is required.

Monitoring has shown the importance of instrument site-selection. Remote sensing to record CO_2 fluxes needs careful consideration and the development of new technology. Achieving consistent and reliable records will also contribute to cost-effectiveness. New techniques that can cover large areas are under development, for example differential adsorption LIDAR and drone mounted sensors. Challenges still remain. Different flux chambers are known to produce differences in measurements by a factor of two. In commercial deployment not only will instrumentation need to be accurate and consistently reliable but there will need to be sufficient expertise to deploy and operate sensory instrumentation.

The lack of instrument consistency and accuracy has also be experienced in marine systems. The measurement of CO_2 and pH do not meet consistent standards. Sensors are required that can compensate for pressure and temperature conditions. Deployment over long time spans of up to three years without correction are under development. Automation, for example Autonomous Underwater Vehicles (AUVs), are a route to wide spread monitoring in marine environments.

Recalibration is an essential practice because instrument drift will always need to be checked. Duplication using different techniques to measure the same parameter should also be practiced to ensure consistency. This approach can be used to cross calibrate instruments. Further development of borehole monitoring using a package of instruments will be summarised in a publication later in 2014.

Session 12 External Perspective and Examples from Other Industries – Chair: Sue Hovorka

A View from a Legal Perspective. Bob van Voorhees, Bryan Cave

The regulatory framework for CO_2 storage sites in the USA involves two interactive sets of requirements, important parts of which were promulgated in December 2010. The underground injection control (UIC) regulations cover the siting, design, construction, operation, monitoring, testing, reporting and plugging and abandonment requirements for injection wells used to inject CO_2 for geological storage. The new 2010 regulations created a new Class VI for wells used to inject CO_2 for storage not occurring in association with oil and gas production. Injection of CO_2 for enhanced oil recovery (EOR) was already covered by the Class II UIC regulations. The other new regulations were developed under the provisions for reporting greenhouse gas emissions and provided, in addition, a system for quantifying the amounts of CO_2 stored geologically with and without being associated with oil and gas production. As established, the regulatory framework uses primarily a performance standard approach rather than a prescriptive approach and should allow for consideration of significant variations from one site and project to another. This adaptability of the requirements is accomplished primarily through the use of a set of plans tailored to each project. These plans delineate the three dimensional scope of a storage project, or Area of Review (AoR) as defined through computational modelling, the testing and monitoring strategies, the post-injection site care and closure strategies, the plugging and abandonment steps for wells, and the emergency and remedial response strategies, as well as the approach for providing required financial assurance.

The flexibility and adaptability provided for the CO_2 storage quantification process is particularly important for addressing fundamental differences in the approaches taken to storage with and without oil and gas production.

The basic approach to storage monitoring under the UIC program and GHG reporting is premised on controlling pollutant emissions and CO_2 storage as an analogue to waste disposal. This diverges sharply from EOR operations, which are premised on the optimal management of valuable resources and commodities to recover resources and avoid waste. Only time will tell whether the regulatory frameworks already created can be adapted to these differing value systems while also accommodating the established sets of rights and contractual obligations associated with oil and gas production projects.

The challenge will be to develop and apply monitoring and modelling approaches that preserve the adaptability of these regulatory frameworks while accomplishing the objectives of protecting the environment and human health, including particularly drinking water sources, and providing requisite assurance of the permanence of containment for geologically stored CO_2. The current frameworks place strong reliance on monitoring and modelling working together through an iterative process of site characterization with appropriately designed data collection and modelling, well construction followed by logging and testing, including formation testing, and then implementing testing and monitoring strategies that are designed to fit the site-specific needs to provide data useful for improving the understanding of site and project performance through the iterative process of data collection and modelling to confirm or modify projections of performance.

The flexibility is there within the regulatory framework to initially match models with available data, recognizing that data availability varies from site to site, and to develop and implement site-specific data collection strategies, recognizing that data availability will increase over time. In addition, these testing, monitoring and modelling strategies should use phased fit for purpose approaches that rely on a normal expected iterative evolution to modify modelling and monitoring during plume development while providing alternative steps to respond to monitoring anomalies.

Session 13 Communicating to Regulators – Chair: Tim Dixon

Modelling and Monitoring in Class VI Permitting. Mary Rose (Molly) Bayer, U.S. EPA and Inci Demirkanli, The Cadmus Group

The Class VI rule was established to counter the potential impacts caused by CO_2 injection. The Underground Injection Control (UIC) programme

elements include site characterisation, AoR, well construction, well operation, site monitoring, post-injection site care, public participation and site closure. Permit requirements are design to ensure the protection of USDW based on a clear, science-based and defensive decision making process. Owners or operators need to communicate their decisions to the EPA and the public.

A key area that forms part of any submission is the delineation of the AoR. The AoR is defined by the maximum extent of the CO_2 plume and / or the pressure front where the injection activity may endanger the USDWs. Operators need to be able to counter dangers to USDWs. Delineation can be determined by modelling but needs to be based on site-specific information. Site characterisation needs to be supported by modelling and tie in with proposed development plans. Challenges that are encountered at any stage, such as lack of permeability data, must be communicated to the EPA. After five years of operation there will be an opportunity to review the AoR in the light of operational experience and monitoring data.

EPA's experience of applications has shown that consistency, specificity and certainty in submissions and communication are the key to successful permit applications. Documenting early experiences in sufficient detail is also essential. Finally AoR re-evaluation and a phased approach to monitoring can provide flexibility to allow projects to adapt to changing conditions.

The regulatory aspects to CO_2 storage raised some important points. Firstly the rationale behind plume tracking. There is a view that it is less important to know exactly where the plume is but it is important to know that it is contained within a reservoir and does not extend beyond the target formation. The plume and pressure front should be within the defined AoR. Therefore it is important to know if over pressurisation will occur.

Discussion – Sessions 12 and 13 Communicating with Regulators Panel Session Discussion. Sue Hovorka, Lee Spangler, Owain Tucker and Molly Bayer

Owain Tucker from Shell outlined the procedure for a UK project (Goldeneye) which is also subject to EU regulations. Approval for an offshore permit is required from three organisations as well as the European Commission (EC). The storage permit is issued by Crown Estate (CE). (The CE has jurisdiction for the foreshore and the sea bed for the sea area apportioned to the UK for energy production). The other two organisations are the Scottish

Environment Protection Agency (SEPA) and the Department for Energy and Climate Change (DECC). The DECC energy development unit also issue a permit under the EU storage directive.

Once the submission is agreed with UK regulators it is forwarded to EC for comment. Experience from the ROAD project shows that communication with the EC is limited and can be delayed.

Lee Spangler from the Big Sky Regional Carbon Sequestration Partnership presented an outline of the implications for potential Class VI submission. The project will extract CO_2 from the Duperow Formation near Kevin dome in north central Montana and re-injecting it into the water leg of the same formation. The first two characterisation wells have just been drilled. Geological information from them will be incorporated into the Class VI permit prior to submission.

For Class VI permits there are no exemptions for USDWs. In this area there are some oil producing zones within the overlying Madison Formation which has total dissolved solids (TDS) below the USDW threshold of 10,000 ppm TDS. This situation may have implications for Class VI regulations and the Big Sky application. The existence of an aquifer which could be classified as an USDW means that the Madison Formation is a protected resource with respect to the Class VI permit. However, waste water injection is permitted into Madison Formation and EOR has also been approved in the area. These factors need to be discussed with the EPA.

Under Class VI the pressure based plume criterion could mean the AoR is much larger than the CO_2 plume. Under the default post-injection site care (PISC) there would need to be 50 years of monitoring but adjustments can be made for the scale of injection especially for research projects with relatively limited quantities of injected CO_2 post-injection site care.

Sue Hovorka gave a Texan perspective. Experience in the state shows that there is a good relationship with regulators. There has been CO_2 injection for EOR since 1972. There is no record of lawsuits for damages to water or other resources under Class II for CO_2-EOR. The implications of previous successful operations for changes set out in Class VI regulations should be considered. Another issue that is currently widely discussed is how to distinguish between CO_2-EOR (subject to Class II) and CO_2 storage (subject to Class VI). The

regulations need to be read carefully to understand the intent and purpose of the regulation. Class II has the same limit on pressure elevation and the same intent of avoidance of transmissive conduits to protect USDWs as Class VI. However, under Class II the AoR is small, typically quarter of a mile (402 m). The area and magnitude of pressure elevation and the areas accessed by the CO_2 plume is controlled by production wells that ring injection wells in patterns, justifying the small AoR. Class VI is fundamentally different because the area of elevated pressure and area of CO_2 are not controlled by production, and therefore the AoR can be large and uncertain.

Molly Bayer stressed that the EPA has regular formal and informal discussions with Big Sky. The EPA is also available to discuss permitting applications with other CO_2 storage applicants. As a regulator the EPA is looking for decision making based on a conservative approach given the comparatively early stage of development of large-scale CO_2 storage projects. An AoR based solely on the extent of the plume may not necessarily reveal CO_2 leakage into thief zones hence the rationale for including pressure fronts.

Class VI appears to be focussed on onshore but not offshore, especially Gulf of Mexico. This was clarified, Class VI does apply in US territorial waters which extend 10 miles (~16 km) in the Gulf of Mexico.

One view expressed is that CO_2 EOR Class II transition to Class VI is prohibitive so the transition will not happen. This is contrary to the experience of some CO_2-EOR operations, for example, the Hastings field which is receiving anthropogenic CO_2 under funding from DOE which requires monitoring for storage effectiveness.

Public acceptability has become an issue. At Quest model outputs were subject to external review by experts who produced formal reviews. Shell recognise the importance of liaison with the public following the company's experience in the Netherlands where there was a lack of consultation. Public engagement is now regarded has essential.

Good news stories are emerging and an excellent pool of knowledge and expertise is now developing from different research and demonstration storage projects.

Combined Topics: Conclusions and Recommendations – Chair: Tim Dixon, Sue Hovorka, Philip Ringrose

During the final session of the meeting a series of conclusions, gaps in knowledge and recommendations were discussed and presented.

- Microseismic data from current projects making progress in identifying risks and reducing uncertainty.
- Monitoring to modelling iteration is proving effective but some uncertainty still remains.
- We are getting more out of pressure gauge data – Snøhvit is a good example
- Microseismics – has clear benefits, even if there are no results. The technique may give insights into induced seismic risks.
- Improved real time data analysis is needed to make reservoir management decisions from fall-off tests and/or multi-rate injection
- At In Salah, despite minimal microseismic deployment, integrated interpretation has provided useful information from the technology
- At Decatur microseismic deployment has been successful and there is a unique baseline. Although baseline can be useful it may not necessarily be essential.
- Commercial application of hydrofrac' operation optimization is bringing new insights – high quality data and analytical tools can be applied for shale gas extraction.
- Need for characterization of seismic risk during site selection. Identification of event origin is important. Ambient seismicity can be very low at some sites. Some sites have very low (not measured) seismic response to injection, and investment in seismic monitoring has low value for the project.
- Modelling can be used to design effective monitoring programmes for example by targeting specific areas that are of interest for geomechanical stability.
- Cost effective planning needs further refinement especially the benefits of deploying different tools and the use of dedicated monitoring wells.

Gaps:

- Need more tools to analyze continuous data
- Monitoring for commercial-scale deployment: what will be the right balance between cost and sensitivity to meet regulatory requirements? Includes costs of monitoring wells.
- Need (shallow) monitoring techniques which are continuous, real time, accurate, and cost effective. There are problems with the accuracy of available sensors and benchmarking of available sensors is required.
- Shallow monitoring techniques that are capable of wide area coverage and detection of small seepage features are required.
- Need to focus measurement on the reduction of stress uncertainty
- Need to reduce uncertainty in velocity models.
- Data to determine long term plume containment and temporal, technical and economic considerations.
- Characterisation of fault zones especially hydraulic and geomechanical properties. Experts in fault properties who have access to large data sets on fault properties should be invited to future meetings.

Recommendations:

- Address gaps identified from this meeting.
- Development of new sensor technology that can produce continuous, reliable and accurate data from field deployment.
- On-going need for joint monitoring and modelling meetings.

2015-07 MONITORING NETWORK MEETING

An IEAGHG meeting, hosted by the Lawrence Berkeley National Laboratory

Introduction to the Monitoring Network meeting 2015

We were very pleased to hold our 10th Monitoring Network meeting at Lawrence Berkeley National Laboratory in California on 10th - 12th June. The venue provided great views over the San Francisco bay area, which complemented the technical programme of presentations and discussions inside.

The 45 presentations and 17 posters covered a range of topics, with sessions on cost-effective monitoring of large projects, permit requirements, induced seismicity, shallow monitoring, geophysical monitoring and CO_2 relationships, pressure monitoring applications, monitoring tools for shallow, surface and deep monitoring, update on projects, and post-closure monitoring. As well as the new results and developments, new at this meeting was a group-work exercise created by Sue Hovorka of the University of Texas. This involved the groups designing monitoring plans for fictional but realistic storage sites, and then these being actually tested with leakage scenarios. The groups were able to apply what they had learnt in the meeting as well as their own expertise, and I'm pleased to say that all the monitoring plans 'caught' the various leakage scenarios!

Also of particular note were the international research collaborations being created around the Aquistore storage site in Saskatchewan and around the CMC controlled release in overburden being developed in Alberta. The Aquistore project has just started injecting CO_2 captured from the Boundary Dam coal power station into a deep saline formation, some 7,000 tonnes injected so far. PTRC has monitoring research collaborations with 26 organisations from 7 countries at this 'field laboratory', and the first monitoring data was shared at this meeting from downhole pressure, seismic, and pulsed-neutron logging measurements.

The overall conclusions of the meeting included identifying the value of pressure based monitoring for assessing reservoir behaviour and in the overburden for leak detection, the potential in fibre-optic distributed acoustic sensing (DAS) and permanent sources, the benefits of good engagement with regulators, the importance of geomechanical analysis

using the monitoring data, and the feasibility of offshore monitoring for leak detection and quantification.

Overall, a meeting packed with new developments in all aspects of monitoring CO_2 storage, shared and discussed by this group of leading international experts. Monitoring continues to make great advances.

Session 1 - Welcome

Welcome from LBNL Associate Laboratory Director Horst Simon, Tom Daley and Tim Dixon, IEAGHG

This 10th Monitoring Network meeting was opened by an introduction from Associate Laboratory Director Horst Simon who emphasised the importance of Lawrence Berkeley National Laboratory's (LBNL) research into fundamental problems including Green House Gas (GHG) control. The facility is engaged in the development of a number of low carbon technologies including artificial photosynthesis to produce biofuels, energy efficiency programmes and CO_2 storage.

LBNL was founded by Earnest Lawrence in 1931 and moved to the present site, overlooking San Francisco Bay, in 1940. It now has an annual budget of $US820M and has defined core capabilities in subsurface science, climate change science and biological systems science.

Tim Dixon from IEAGHG stressed the importance of CCS in stablising CO_2 emissions. This is evident from the recent IPCC 5th assessment report, published in November 2014, which has concluded that without CCS costs of CO_2 mitigation could increase by 138%. The inclusion of CCS in modelled scenarios will be a key technology required to stablise CO_2 at 450ppm and limit average global temperatures to 2°C.

Session 2 – Monitoring for Large-Scale Industrial Projects – How are Large-Scale Projects Monitored Cost-Effectively and how is Sufficient Sensitivity Achieved? Chair: Curt Oldenburg

Integration of Dynamic Multi-Sensor Surveillance during an injection program at Lost Hills California. Paul Harness, Chevron

The Lost Hills injection programme is a pilot project where an integrated surveillance programme was designed to capture uncertainty and provide a basis for alternative production strategies. The objective of this approach was to reduce uncertainties related to induced treatment, variation in

production flow and the range of well production. The surveillance included three microseismic monitoring wells plus one horizontal well with a fibre optic temperature sensor. Other wells had pressure monitors. The sensor configuration was established so that microseismic events could be detected with a resolution of a few feet (~1 meter) via triangulation. InSAR, GPS and tilt meters were also deployed. Observation data from the field was then transmitted to a distant location for interpretation. This combination of parameter monitors provided temporal data flow at frequencies of a few seconds to daily and monthly periods. Integration of different data streams was essential to interpret how the reservoir behaved. Understanding flow patterns, pressure variation and other parameters is important to control production which is also governed by the necessity to inject and produce from specific horizons and maintain wellbore integrity.

Experience of data integration and interpretation has revealed how the Lost Hills reservoir responses can be linked. A good example is the association between microseismicity and injection cycles. Microseismic events can be linked to a single well cluster around fractures in the reservoir. Another example is the use of subsurface pressure monitoring to optimise the production rate. Pump performance can be used to monitor pressure in reservoir. Reservoir pressures can also be inferred from sensitive monitoring using surface deformation with InSAR. The technique revealed a lack of pressure difference across this reservoir which enable operators to alter the pressure regime. Variation in tilt meter data from several monitoring points also allowed operators to visualise variations specifically fluid movement across the reservoir.

The overall conclusion is that subtle monitoring of different reservoir parameters can be integrated to reveal temporal and spatial variations that can be used to modify and optimise production.

Peterhead – Goldeneye Project. Owain Tucker, Shell

The Peterhead – Goldeneye project will capture 90% of the CO_2 from a 300MW gas turbine. The CO_2 will then be injected into the Captain aquifer which is a turbidite sandstone with a darcy level of permeability. The monitoring programme has been designed to show containment and conformance. A Bowtie method of risk assessment has been developed to identify potential migration routes, barriers and mitigation measures for each risk.

Linked bowtie assessments have been developed for different risks. For example releases from wellbores into undesignated formations. A control philosophy can then be applied to identify scenarios of where CO_2 might migrate to. The monitoring programme is then designed to detect the presence of CO_2 and the mitigation measures that might be applied. Monitoring techniques would then be selected on the basis of cost-benefit. For example, seismic is selected to monitor for potential reservoir fluid movement below the original water contact because it provides the best spatial and temporal resolution. There is a mix of residual gas, CO_2 and water, however the use of seismic clearly shows the temporal movement of CO_2. 3D Vertical Seismic Profiles (VSP) might be able to show CO_2 movement in a reservoir but this approach is unproven. New technologies are being investigated, but the application of any technology needs to satisfy regulators and therefore needs to be proven and established technology. Distributed Acoustic Sensing (DAS) fibres have the ability to record 3D VSPs. If the technique works then it could be a more cost-effective method for tracking CO_2 in reservoirs.

The seismic risk from an event 100km offshore is minimal. Sensitive onshore monitors at this distance would only detect an event at Magnitude 4 or above. In conclusion this monitoring programme is designed around a thorough and integrated bowtie risk assessment methodology that identifies potential risks, barriers to migration out of the designated reservoir and mitigation measures. Seismic provides the most cost-effective measure for tracking CO_2 movement and VSP could be highly effective once fully tested and proven.

Developing Monitoring Programmes for Large-Scale Projects: the Experience from CO_2 EOR. Sue Hovorka, BEG

This is generic summary of three US DOE funded projects to monitor CO_2-EOR operations. At present there is no qualified plan for monitoring storage related to CO_2-EOR. The challenge for these projects is that operators are only interested in the most efficient sweep and do not want any oversite or reporting of CO_2 retention. The potential benefit for CO_2-EOR operators is the increase in the supply of CO_2 from anthropogenic sources. Effective demonstration will also help to convey the positive benefits to the wider public. Existing hydrocarbon reservoirs also have provable seals and have good reservoir characterisation.

EOR floods can be controlled by the operator. Moreover, 40 years of experience in a commercial environment shows that CO_2-EOR is highly effective. Operators claim that they have good knowledge of well status and pressure gauges are an effective means of monitoring conditions. CO_2-EOR can lead to CO_2 moving to wells in an adjacent operation. This condition can be controlled by a water curtain. However, it could be assumed that at the end of the project, ending the water curtain will lead to CO_2 migration forming a stable configuration. More evidence about the technique would help to establish its effectiveness.

There are important issues to consider about the end of the project. The pattern of CO_2 migration is different from hydrocarbon migration and its distribution within a reservoir will also be more rapid because of its miscibility properties and its viscosity. No CO_2-EOR operations have been stopped, so there is no experience with a project end. In US oilfield operations, there is no transfer of liability post-project end. Quaternary[1] recovery might also become an issue.

Commercial CO_2-EOR operations can be a highly effective means of storing CO_2 and developing a supply chain from anthropogenic sources. Commercial operators are understandably reticent to release technical data or report CO_2 retention. Post-closure status is also a potentially contentious issue but CO_2-EOR could offer a route to the expansion of CCS.

Discussion – Session 2

The development of CO_2 storage from commercial CO_2-EOR operations is currently constrained because of commercial confidentiality. Operators guard their expertise in conducting CO_2 floods and dislike releasing detailed information on well status. They are also reluctant to discuss operational difficulties. Reporting could be designed to demonstrate an inventory of retained CO_2.

Monitoring programmes can be rationally planned to be cost-effective. For example, a monitoring plan based on risk assessment should be able to identify where risks are most likely to occur and the most effective remediation. Monitoring every wellbore may not be practical but pressure monitoring may be an effective means of detecting an anomaly. In Salah is a

[1] The term Quaternary Recovery is used to refer to more advanced, speculative, EOR techniques

good example where an increase in pressure caused microseismicity which, combined with other factors, led to the cessation of injection. Remedial action has also been effectively demonstrated by seismic and pressure monitoring in the Snøhvit field. Injection has been switched to another stratigraphically higher formation.

The development of monitoring programmes begins with a conceptual model to build risk scenarios. No single monitoring system will provide a complete picture. Multiple systems with integrated data analysis will provide a more detailed appraisal of reservoir behaviour. The monitoring programme can then be designed to address risks. It may also lead to the development of new technology if there is a gap in capability. Distributed Acoustic Sensing (DAS) is a good example.

Microseismic events are related to natural fractures. The technique, in combination with wellbore logs, can detect linearity and the pattern, position and size of fractures. Very low detection levels (-3ms) are now possible from sensors in vertical wells and give a much better resolution compared with surface monitoring. Microseismic monitoring can also provide an indication of a well's production performance

Session 3 - Permit Requirements under the Three Objectives of Conformance, Containment and Contingency. Chair: Tim Dixon

Act on Prevention of Marine Pollution and Maritime Disaster for offshore CO_2 Storage in Japan. Jun Kita, RITE

Tomakomai is one of two Japanese CCS demonstration projects. Injection will begin in 2016 and continue until 2018. 100,000t per year will be injected into a subsea reservoir off the coast of this Japanese city. The regulation of CO_2 storage in Japan is covered by the Act for the Prevention of Marine Pollution and Maritime Disasters which was amended in May 2007 to permit CO_2 storage in offshore formations. The act requires consent from the environment minister and the implementation of an Environmental Impact Assessment (EIA). The EIA must include an assessment of the potential dispersion of CO_2 from a leak. The act also specifies three key compliance criteria conformance, containment and contingency.

The Act stipulates that a three tiered monitoring plan must be implemented depending on the severity of changes that could occur following CO_2 storage:

- Normal time monitoring i.e. no indication of leakage
- Suspicious time monitoring i.e. possible leakage
- Abnormal time monitoring i.e. leakage has taken place. The location of the leakage needs to be determined and its impact.

In conclusion the regulation of CO_2 storage in Japan is covered by the Act for the Prevention of Marine Pollution and Maritime Disasters. The act requires adherence to conformance, containment and contingency criteria. This regulation is already developed. The operator, the Japan CCS Co Ltd, is now in the processes of applying for the permit.

Monitoring Programmes in the ROAD Project. Philippe Steeghs, TNO

The ROAD CCS project was the first to receive a permit under the EU storage directive. The CO_2 will be sourced from a 250MW power plant post-combustion capture unit located on the Maasvlakte near Rotterdam. The scheme will supply a planned 1.1Mt CO_2 / year via a 25km offshore pipeline before injection into a depleted compartment of the P18 gas field.

The monitoring plan has been formulated on the EU storage directive which is focussed on safety and integrity. The project is technically relatively simple in comparison to other CO_2 storage projects, with a single well penetrating the reservoir and minimal equipment installed on the offshore platform. In spite of this thorough approach to monitoring will be adopted. As new techniques and equipment are developed, these will be included whenever judged appropriate provided that these techniques do not add to the complexity or cause significant interference with other operations. Hydrocarbons will continue to be produced from neighbouring compartments throughout much of the project timeline.

The monitoring and contingency plans are part of a set of related plans that are part of the storage permit. A site specific risk assessment is the main input for the corrective measures and closure plans. The development of the monitoring plan is also based on a site specific risk assessment and has strong links with the corrective measures plan. Its status as a demonstration project requires the reporting of operational and technical information. Commercially the project also needs to satisfy ETS. The current monitoring plan will be updated before injection starts.

The monitoring plan is based on a site-specific risk assessment of the storage site. Reservoir integrity is a key consideration. The P18 field is subdivided into four distinct reservoir compartments. The planned storage location is the P18-4 compartment. The sealing capacity of bounding fault (P18-4/P15-9) has been studied extensively but remains an uncertainty to a certain level. There is a storage permit for the two compartments on either side of the fault. One of the permit conditions is an assessment of potential movement across this fault which separates these two compartments. Migration across the fault would be detected by a pressure gauges in the reservoirs.

A traffic light approach has been developed in anticipation of a potential escalation from a predicted condition where data fall within a specified range (green), to irregularity in expected data (yellow), to a condition where observed data are outside the expected range and a scale-up in monitoring intensity and model refinement is required (red).

Across this location the storage reservoir seismic response is not expected to show much detail therefore pressure monitoring is the most important form of monitoring activity. However, it is foreseen that a baseline seismic survey will be conducted for shallow sediments in the overburden, with additional seismic surveys as an option in the contingency monitoring plan. Regular well integrity and monitoring is also planned. A series of corrective measures are planned in case there are indications that there may be movement of CO_2 outside the designated reservoirs.

Throughout the process of developing the documents for the storage permit application, there has been frequent contact with the competent authorities. This has helped the operator and authorities to develop an understanding of the risks associated with storing CO_2 in P18-4. Moreover, frequent meetings have helped both parties to address all the issues covered in the EU Storage Directive and the level of detail required. The application for storing CO_2 in P18-4 was the first to be undertaken in The Netherlands, and the frequent contacts during the permit application preparation period helped shape the process for both operator and authority and provided clarification for elements of the Directive that are left open-ended.

Monitoring of Decatur Project, ADM CCS Projects UIC Class VI Permitting Experience. Scott McDonald, ADM / Randy Locke, ISGS

The Illinois Basin Decatur Project (IBDP) is a large scale >1MtCO2 /year CO_2 storage project into the Mt Simon Sandstone deep saline aquifer (DSA) in central Illinois. The second stage of this project has a permit to inject 5.5Mt over five years. The CO_2 is sourced from a bioethanol plant at 99% purity. The DSA has a shale cap rock plus secondary and tertiary seals. There is another sandstone formation, the St Peter Sandstone above the primary seal (Eau Claire Shale), which is classified as an underground source of drinking water (USWD), although only shallow aquifers above this formation are used as sources of drinking water. The St Peter Sandstone has to be monitored because of its USWD status.

Injection at Decatur (first stage) was permitted in 2011 under Class I after initial application in 2008. The permit application process for post closure monitoring began in 2011 and final approval was given in December 2014. Concern was raised over the 50 year post-injection site care (PISC). Consequently, the site operator, ADM, proposed a 10 year timeframe based on evidence of a decline in reservoir pressure, plume stabilisation and CO_2 partitioning. The monitoring programme was designed to meet the requirements of a 10 year PISC. After 10 years the site operator must be able to demonstrate non endangerment and conformance of recorded data with predictive models particularly pressure. The model will then become the proxy for demonstrating stabilisation and containment of CO_2. The analysis showed that if the plume did not stabilize and continued to expand 1% per year, it would take ~600 years for the plume to reach a nearest penetration of the seal formation 17 miles (27.4km) from the injection point. Two 3D time-lapse seismic surveys are planned to compare with previous baseline surveys, however reservoir heterogeneity means that pattern of the CO_2 plume does not form a clear image.

Experience from the Class I application shows that proactive engagement with regulators and technical collaboration with them proved beneficial. The US Environment Protection Agency (USEPA) focused on technical, risk-based permit decisions that often required additional information. Discussing models in detail and the use of published examples in support of permit applications helped. Regulations will drive primary monitoring activities but

other environmental baseline monitoring may be necessary to reduce risk regardless of regulatory requirements.

Discussion – Session 3

Monitoring requirements for CO_2 storage sites is partially driven by regulation. In the USA and Canada protection of fresh water aquifers is a key priority therefore the area of elevated pressure where brine or other potential contamination could be lifted is highly relevant. Modelling shows that this is unlikely to occur. For offshore storage the CO_2 footprint is still important but brine movement is less significant as there are no fresh water aquifers.

Models are an essential tool for predicting future conditions but they can also be used to project extreme scenarios that show the limits of conditions that might occur.

Pressure monitoring is an effective technique for detecting CO_2 leakage, but it may require other techniques, or several monitoring points, to detect a leakage pathway or a CO_2 accumulation. The monitoring frequency also needs to be decided to determine the detection threshold of CO_2 and its migration path. The EU storage directive says detection must be at any level. In the US regulators base their judgement on whether models are compliant with monitored data.

Regulators could drive the permit process based on existing frameworks but it is also possible that existing frameworks are formulated by the interaction between themselves and operators. Experience in the USA, Europe and Japan is revealing a pattern of regulators relying on interaction with operators. Project planning by operators is meeting generic requirements which in turn is helping to educating regulators.

Session 4 - Induced Seismicity: how can we Devise a Monitoring Strategy for Safe Operation? Chair: Jun Kita

Strategy for Monitoring Large Regions of Fluid Injection Induced Seismicity: Oklahoma's Experience. Austin Holland, Oklahoma Geological Survey

Across the state of Oklahoma there are about 4,000 saline waste disposal wells operated by over 100 companies over an area of 25,000km2 (~9,653 miles2). Saline disposal is governed by Underground Injection Control (UIC) Class II temporal and spatial waste water disposal regulations. Since 2008 there has been a dramatic rise in Magnitude 3 and Magnitude 4 (M4)

earthquakes. Despite the state wide network of seismic stations regional uncertainties mean that quake foci could only be tracked to within ~8km. With a rise in seismicity in certain areas the regional network was augmented with a higher density of stations which led to an improvement in quake foci to within ~1.5km.

Oklahoma Geological Survey implemented a more proactive and responsive surveillance programme by increasing the coverage of stations particularly in areas of concern. This higher density of temporary monitoring stations is mostly within a central belt of the state. This initiative has led to a rapid increase in the detection threshold. Disposal wells with the highest volume of injected saline coincide with highest concentration of quakes. The Arbuckle group of dolomitic limestones, is the predominant recipient of injected saline. This formation directly overlies basement where seismicity occurs.

The rise in seismicity associated with saline disposal has led to a change in requirements for monitoring. Previously there was an eight month lag between injection and reporting of disposal operations represented as monthly averages. In 2014 the new regulations demanded daily records of injection rate, volumes and pressures to improve data granularity. Weekly reporting for Arbuckle group and non-Arbuckle group wells is also required in specified areas of interest. The proximity of two recent M4 earthquakes was within 20km of a seismic station which has improved the data quality associated with them. The increase in the density of monitoring stations has also improved the location accuracy of quakes. Ground acceleration and ground motion data is archived and is publically available.

Induced Seismicity Protocols used in Geothermal Energy Development. Protocol and Best Practice for addressing IS associated with EGS. Ivan Wong, AECOM

Induced seismicity is not a new phenomenon and is associated with several industries including mining, oil and gas, wastewater disposal as well as geothermal. Hydraulic fracturing is used in enhanced geothermal systems (EGS) to open and track fractures patterns and associated fluid flow. Some EGS projects have caused felt events to occur, for example the M3.4 in the Swiss city of Basel. Although there was no structural damage the project was closed. The US Department of Energy (DOE) has developed a protocol to address public concerns and an advisory document which identifies

important issues and provides possible mitigation measures.

The Geysers field in northern California is the largest conventional geothermal field in the world. To boost energy output some EGS hydraulic stimulation has been recently applied. Seismicity is commonplace and affects two communities about 5km from the seismic activity. To date, more than 30 M4 and larger events have occurred since 1972 with the largest earthquake being a M4.7. An outreach programme has been implemented to communicate issues related to induced seismicity. Experience has shown that operators should be proactive and need to identify local stakeholders and be aware of the impact of potential induced seismicity. Risk-based mitigation plans also need to be developed. Local conditions at each site will call for different types of action. The protocol developed by DOE is a seven step process beginning with a screening evaluation which includes a preliminary risk assessment of the probability of structural damage or other adverse effects such as landslides. The next step is to develop an outreach and communication programme. Experience of geothermal energy development in the US to date shows that there have been no instances of significant damage. The next step is to set up seismic monitoring and quantify the baseline hazard from natural seismicity. The next stage is to characterize the risks in terms of physical damage to buildings and infrastructure, interference with human activities and socio-economic impacts. The final stage is to develop risk-based mitigation plans.

In summary this is a good example of an initiative to deal with the effects of induced seismicity through the development of a flexible protocol and best practice guidance.

Seismic Monitoring in the Tomakomai Project. Daiji Tanase, Japan CCS Company

The Tomakomai CCS project will capture CO_2 from off gas of a hydrogen production unit of an oil refinery located near the port of Tomakomai on the Japanese island of Hokkaido. Two injection wells have been drilled onshore near the oil refinery and deviated to two different offshore reservoirs. The highest reservoir is a sandstone formation (Moebetsu) at a depth of 1.1 – 1.2km. The lowest is in the volcanic Takinoue Formation at a depth of 2.2 – 2.8km.

A 3.6 km long Ocean Bottom Cable (OBC) with 72 seismometers and four Ocean Bottom Seismometers (OBS) have been deployed above and surrounding the injection site plus three observation wells and one onshore seismometer. The onshore seismometer complements the blank area of the national Hi-net (High Sensitivity Seismograph Network of Japan) stations to provide a record of baseline natural seismicity of the Tomakomai region. Three observation wells have pressure / temperature sensors and seismic sensors. Baseline 2D and 3D seismic surveys have been completed and will also be conducted to track the progress and distribution of CO_2. Injection begins in April 2016.

Japan is prone to natural seismicity consequently understanding the magnitude and location of seismic events is especially important. In the Tomakomai region an earthquake of M4.4, with an epicentre 17km from the injection site, was observed in January 2015 at a depth of 29.9km. A month later a M1.5 event was detected 14km from the injection site at a depth of 24.1km. More recently, in May 2015, a <M-2 event was observed in the project area at a depth of 5.45km, which is an example of frequent natural microseismicity.

Induced Seismicity linked to Fracture Zones in the In Salah Field. Bettina Goertz-Allmann, NORSAR

Induced seismicity has been monitored and interpreted at the In Salah field and used to delineate subsurface fractures. At In Salah 4Mt CO_2 has been injected into a naturally fractured sandstone reservoir. 5,000 microseismic events were recorded between August 2009 and June 2011. Because of a technical fault only the uppermost geophone at 80m depth provided reliable data for detailed analysis. With only 1 geophone it is not possible to accurately locate events. However, several clusters with similar arrival-times can be differentiated. The differential S-P onset times give an estimate of event-to-receiver distance. The event direction can be inferred from the particle motion of P-waves. By combining S-P, azimuth, and inclination, four different clusters can be separated.

The b-value[2] of S and P wave magnitudes allows extrapolation from observed small events to expected larger events. The b-value can also be linked to

[2] (slope of the Gutenberg–Richter law describing the relative size distribution)

the in-situ reservoir stress state. There are significant variations in b-values between different clusters. High b-values (1.5 – 2) observed in three clusters suggest opening of new fractures whereas a lower b-value (~1.0) observed at the most distant cluster may be related to pre-existing fractures.

Shear wave splitting has also provided useful information. Three clusters have anisotropy of up to 5%. In contrast one cluster has an anisotropy value of <2%. This analysis has been used to aid a geomechanical appraisal of the reservoir particularly by comparing different event clusters with injection history. The most distant cluster showed no correlation with injection data in contrast to the other three. One cluster in particular showed a high degree of activity but only during the main injection phase.

Detailed analysis of microseismicity and comparison with injection history allows differentiation between two distinct event classes. Class I events are furthest away from the injection point and may be located about 150m above the reservoir formation top in the lower caprock. They are not directly correlated to injection history. Their b-value (~1) indicates seismicity on pre-existing faults. Class II events are highly correlated to the injection history. Higher b-values of 1.5 to 2 are observed, indicating new fracture opening. Strong anisotropy is also observed.

Discussion – Session 4

The theme for this discussion session was how to devise a monitoring strategy for induced seismicity. Each contributor put forward a view based on their experience:

Austin Holland, from the Oklahoma Geological Survey, remarked that data acquisition for seismicity linked to CO_2 storage is greater than for waste water disposal. He also stressed the importance of data acquisition through time especially from the beginning of operations.

Ivan Wong, from AECOM, observed that induced seismicity is used in the development of geothermal energy and monitoring is essential for this purpose. Given the locations where geothermal energy is developed higher magnitude events are more likely (~M4). These events need to be recorded as part of a mitigation strategy.

Daiji Tanase, of the Japan CCS Company, stressed the importance of being

able to distinguish natural seismicity, which is prevalent, from induced seismicity. CO_2 storage is a new technology in Japan and therefore it is necessary to avoid felt events. Consequently, CO_2 injection needs to be carefully controlled.

Bettina Goertz-Allmann, from NORSAR, stated that a good depth resolution, plus coverage to improve the resolution of event locations and detailed source analysis, was important. This will require a comprehensive sensor network. Real time data acquisition and interpretation can enable microseismic data to be used to guide injection and other operations. There is a strong relationship with pressure build-up in reservoirs which can be used for geomechanical modelling. One of the differences between waste water disposal and CO_2 storage is injection into thin bounded reservoirs. Fluid rheology properties are also different.

Local attitudes in the vicinity of the Decatur site would strongly suggest felt events should be avoided. Best practice procedures are applied. Induced seismicity that might cause the reactivation of faults should be avoided which might mean shifting the location of injection.

Depth control using surface and shallow observation boreholes is a good monitoring approach because it can provide more detailed information on low magnitude events. Induced seismicity can also be related to geomechanical models to give predictive capability on faults and caprock thresholds.

In Oklahoma and Illinois reactivation of basement structures is the cause of induced seismicity therefore injection at stratigraphic higher intervals is preferable. The basement is heavily faulted which can generate induced seismicity to the extent that injection above basement in Ohio is banned. M3.4 events associated with water injection have been recorded in the Youngstown area of Ohio but the magnitude of events in the Decatur area are much lower. This suggests the geomechanical properties of the basement are different and that the overlying Mt Simon Sandstone CO_2 storage potential should not be discounted. The stress state and the properties of the Mt Simon Sandstone need to be properly characterised. During injection reservoir pressures need to be controlled to avoid inducing slip on fault planes. Experience of microseismicity associated with CO_2-EOR

in the Cogdell field, Texas has not stopped operations. The disposal of high volumes of saline could have implications of CO_2 storage capacity but further research is needed.

If thousands of millions of tonnes of CO_2 are to be stored in the Mt Simon formation it means that attention should be given to geomechanics which may limit the amount of CO_2 that can be injected because the basement may have a large number of stressed faults that could be reactivated.

Session 5 - Shallow Monitoring: how much do we need and how can we do it? Chair: Charles Jenkins

Scene setting – the Detection-Attribution-Quantification cycle. Katherine Romanak, BEG

The detection-attribution-quantification cycle is a key aspect of potential leakage detection. In this session the experience of four practitioners with expertise in different aspects of surface monitoring presented their views. These researchers were: David Risk, St. Francis Xavier University, (soil gas); Jerry Blackford, PML, (marine); Susan Carroll, LLNL, (ground water); and Sarah Hannis, BGS, (atmospheric monitoring).

Katherine Romanak from BEG outlined some of the challenges related to surface and shallow monitoring which can be directly related to water, air quality, ecosystem quality or landscape changes. The two key components are the detection of an anomaly and attributing its source. A multidisciplinary approach is necessary as well as the education of regulators. She emphasised that there are a number of practicalities with data acquisition from highly variable natural systems and a careful approach is necessary. Monitoring techniques also need to consider the implications implementing CCS on an industrial scale. Although different media may present different challenges the objective of monitoring is to detect anomalies and characterise a baseline that demonstrates a lack of leakage, or if a leak has occurred, it can be quantified. Under these circumstances monitoring would be used to detect the source of the leak and enable operators to respond to potential public claims. There will always need to be a balance between economy and the feasibility of locating a leak as well as the perception that leaks will occur or the extent to the risks that they pose.

Baseline may take one and three years of pre-injection monitoring to

understand seasonal variations. Spatial and temporal variations in a baseline could mean leakage has occurred but without complex reasoning and statistical analysis it may not be possible to differentiate between a leak and background variability. However, baselines will be highly dynamic and will fluctuate with climatic and land use influences over the life-time of a project. A sound investigation and analysis at Weyburn using complex statistical analysis of multiple geochemical parameters proved the site was not leaking but this example demonstrates how careful any monitoring programme, and its subsequent interpretation, needs to be. Understanding the process which causes a phenomenon not the absolute concentration is fundamental. The transition from research and demonstration sites to industrial-scale projects will also demand a minimalistic approach. A balance needs to be struck between operator and regulatory goals.

Dave Risk presented the example of monitoring soil gas. Detection and attribution based on 20 – 25 geochemical indicators would give a clear indication of leakage, moreover, background surface monitoring can be minimised. Some caution does need to be applied because leaks can be caused by defective infrastructure from surface sources unrelated to subsurface origins. Following risk assessment logic rather than widespread and unnecessary monitoring is likely to be far more effective. Therefore monitoring for leakage detection should be specific.

The challenge of monitoring in a marine environment was presented by Jerry Blackford. He stressed that no single monitoring technique is sufficient. There are important criteria to consider. The area of survey will be dependent on technology power requirements. The detection sensitivity of the technology will determine its valid range. For example the acoustic effect for bubble detection extends to ~100m. Marine ecosystems such as the North Sea have complex baselines. Therefore the use of biological indicators requires detailed baseline appraisal that incorporates the influence of seasonality. Natural variability adds further complexity.

Targeted sampling in the proximity of wellheads is likely to be the most effective approach. Good baselines are vital to reduce false positive and non-detection of genuine anomalies especially at the initial stages of large scale offshore demonstration projects. The frequency of monitoring can be varied. A few periods of intense high frequency monitoring may be required in some

instances whereas less frequent, monthly, yearly or even surveys repeated after a decade could be appropriate.

The case for ground water was presented by Susan Carroll. Changes to ground water can be caused by small amounts of CO_2 and brine which can change pH and total dissolved solids (TDS) above thresholds. The ability to detect small leaks is only possible over long periods of time and if the monitoring point is near a wellbore. The simulation of plume volumes can be an effective means of predicting the impact of leaks and therefore where to deploy monitoring sensors. Pressure changes will be best method for detecting leaks but a well density of more than one well per km^2 is probably necessary.

Sarah Hannis outlined the issues related to atmospheric monitoring. The detection of anomalies is the greatest challenge based on the studies of natural analogues and test release site evidence which indicates leakage is likely to occur on the scale of meters to 10s of meters. This research also shows that CO_2 rapidly disperses and mixes. It is very difficult to detect anomalies unless there is a large density of eddy-flux towers. Ground laser sensors are a possibility for wider coverage. False positives are always possible with any system.

Attribution is more difficult for CO_2 concentration alone but carbon isotopes and gas ratios, especially with CH_4, have been shown to work. Diagnostic site signatures can be helpful. Continuous monitoring offers the best chance of not only detecting leaks but also quantifying them but this approach will only be effective with frequent surveys.

In response to these views one operator commented that a balance needed to be struck between the level of monitoring and the obligation to meet regulator requirements. Under US federal Class VI requirements 28 parameters now need to be monitored. This condition tends to lead to a blanket approach rather than a more focussed plan. The experience of other practitioners stressed the importance of good site characterisation. At Ketzin intensive site monitoring, including soil flux measurements, was implemented to demonstrate to the local populace that natural processes and natural variability were fully studied and understood.

In marine environments low levels of CO_2 from a seep have negligible impacts but this perception could be contrary to public acceptability. Characterisation

of natural variability is very useful for general scientific research not just CCS. However surveys around injection wells need to be able to detect changes that might be linked to injection. The presence of bubble streams would be monitored at the highest areas of risk to gain a better understanding of natural changes not necessarily because of risk.

Session 6 - Developing the Link between Geophysical Monitoring Responses to CO_2 Distribution, Pressure and Saturation in Reservoirs. Chair: Andy Chadwick

New Developments of CSEM (Controlled Source Electro-Magnetic) to Map CO_2 Distribution and Saturation in Reservoirs. Pierre Wawrzyniak – BRGM

The CSEM method in LEMAM setup uses energised metallic casings as long electrodes to induce currents directly at the depth of the reservoir and then retrieve the electrical resistivity signature of a supercritical CO_2 plume from surface measurements. The resistivity within the reservoir is altered by the injection of CO_2, which creates a resistive body inside the conductive reservoir. Because of the presence of clay in the reservoir, imaged resistivity needs to be corrected in order to obtain a clear CO_2 signature.

At the Hontomìn Spanish pilot injection site, the technique was applied for a baseline campaign in December 2013 using one steel cased borehole and surface electrodes. Later CO_2 was injected but only in small quantities (5-10kT of CO_2). 96 receiver stations were deployed and electric currents were induced for seven different frequencies. By integrating signals from these stations, and fixing their position using GPS, it will be possible to monitor resistivity variation induced by CO_2 injection across the field.

The technique has also been applied for geothermal exploration in Martinique with two steel cased boreholes. Subsurface conductive areas were imaged and are related to temperature anomalies. The conductive area is consistent with high wellbore temperature measurements and models.

At Ketzin two sets of eight electrodes were used in two boreholes at 550m depth. There were 14 surface receiver stations. A baseline survey was conducted in 2008 followed by three repeat surveys in 2009, 2010 and 2011. Results were then compared with a 3D forward model associated with different plume propagation scenarios.

CSEM can be a useful imaging technique that is complementary to seismic

profiles. It can also be used to monitor the progress of the plume. The technique still requires further refinement. A 3D inversion code is being developed to improve resolution.

The Surface Deformation Measurements for Monitoring, Verification and Accounting (MVA) of Injected CO_2. Tim Dixon, University of South Florida

InSAR is a satellite-based technique which can be used to measure very minor changes in surface elevation (~mm). Comparison between baseline data and later surveys can be directly related to changes in underlying reservoirs. The technique is particularly well suited to deserts but recent research shows that it can be effective in more heavily vegetated regions. Reflectors can be used to enhance the response signal to satellites. The SBAS (Short baseline subset) technique can also be applied. It relies on the selection of interferogram pairs based on optimum perpendicular (spatial) baseline and temporal baseline.

A 10cm uplift in the SAROC field, west Texas, has been matched to CO_2 injection. A series of satellite images have been used to work out the rate of uplift and compare it with cumulative CO_2 within the reservoir. Residual differences between observed and modelled images are attributed to reservoir heterogeneity.

In another example GPS observations were used to monitor an EOR field in south Texas. The field was subdivided by faults.

In this case GPS data was used because it was available over most of the EOR-injection operation. A regional reference frame signal compiled from a series of other regional GPS stations was used to filter the noise from this site. Several stations rose by amounts up to 1 cm, correlated with an increase in reservoir pressure. Other areas did not show vertical elevation. The elevation change was related to part of the reservoir where pressure increased during CO_2 injection. The subtle difference in elevation across the field showed that injected fluids remained entirely within a delineated fault block, suggesting that the fault has a sealing function. In this case vertical motion can be directly related to a pressure response and can be used to measure it.

Surface deformation techniques can provide a low cost MVA technique that can augment more detailed wellbore and seismic techniques. InSAR can be used in some areas of sparse vegetation without ground reflectors, while high precision GPS can be used in areas with increased vegetation.

Continuous Monitoring of Injected CO_2 using Ambient Noise and Controlled Seismic Source. Takeshi Tsuji, Kyushu University

The objective of this research project is to develop a method of seismic interferometry to monitor injected CO_2. The technique relies on the retrieval of seismic data from ambient noise. Time-lapse seismic surveys using an active-source is a high cost approach. A continuous monitoring system, based on seismic interferometry, has the potential to be a cheaper alternative using ambient noise. The technique relies on the propagation of a wave at depth which is recorded by a seismometer at the surface. The wave is reflected back into the subsurface and is then reflected off subsurface structures before returning to the surface where it is recorded by a second seismometer. By using a second, active source at the surface near the first seismometer another waveform can be created. Cross-correlation and cross-coherence of the waveforms eliminates the path from the source to the first seismometer leaving a signal that is representative of a reflection from the subsurface structure. The technique was tested using a fluid injection experiment in Spitsbergen. In this case the ambient noise was mainly derived from the injection well. The seismic survey enabled the generation of time-lapse reflection profiles to be created before during and after fluid injection. The pattern of fluid migration can then be traced. The technique relies on ambient noise from a stable source.

To generate a continuous frequency-controlled seismic source at the surface, the Kyushu University team developed an active source system "small-sized Accurately Controlled Routinely Operated Signal System (ACROSS)" to produce a consistent, continuous frequency-controlled seismic wave in a CO_2 storage field. The system has the advantage of producing a high quality repeatable source enabling continuous signal acquisition and a higher signal to noise ratio. This allows continuous monitoring during CO_2 injection. A small field test of the system has been conducted at Toyohashi in Aichi prefecture in the central part of Honshu. Because of the short offset of the seismometers it was difficult to analyse the reflection waveform. Analysis of the surface wave could be used, however, to determine the time variation of S-wave velocity. Comparison with a model of CO_2 migration showed that small changes in P and S-wave velocities (~5%) induced by the presence of CO_2 can be monitored (or detected) using this approach. The research team has been able to show that the techniques using surface waves can detect

the presence of CO_2 in shallow formations which has the potential to be used for leak detection.

Seismic Reflections at Sleipner: How Have they Changed with Time and What do they Mean. Andy Chadwick, BGS

Sleipner has been the subject of detailed seismic investigation for around two decades. 3D time-lapse seismic surveys have revealed a pattern of CO_2 migration within a plume comprising nine different layers trapped beneath a series of successive thin mudstones in the reservoir. By 2010 improved seismic resolution enables some of the layers to be resolved, with explicit separation of the top and base reflections. The topmost layer of CO_2 has accumulated beneath the topseal by a buoyancy-driven fill-spill process governed by the topography of the caprock. Forensic interpretation focused on the CO_2 accumulation beneath a particularly well-defined ridge in the topseal. This has enabled the key relationships between ridge elevation, temporal layer thickness and velocity pushdown (time-shifts) beneath the ridge crest to be measured. It is clear that strong tuning effects beneath the ridge flanks give way to much weaker tuning beneath the ridge crest where temporal separation of the top and base reflections is observed. The ratio of velocity pushdown to ridge temporal elevation is a key parameter, diagnostic of layer velocity.

A series of synthetic models was built to simulate different thicknesses of the CO_2 layer and different ridge elevations and to take into account the variable interference effects depending on layer temporal thickness. Correlation of the observed time-shifts with synthetically derived time-shifts enables the ridge elevation and layer thickness parameters to be isolated and layer velocity estimated. Very preliminary results suggest layer velocities in line with earlier rock physics calculations, but work is ongoing.

In conclusion improvements in seismic resolution have enabled advances not only in the detection of CO_2 but also in forensic analysis of CO_2 layer properties.

Gravity Surveys over Time at Sleipner. Håvard Alnes, Statoil

Gravity as well as seismic surveys have been conducted across the Sleipner field to test the changes induced by CO_2. ~15Mt of CO_2 has been injected to date. The subsurface mass changes caused by this injection induce subtle

differences to gravity measurements. However, account also has to be taken of water which moves up into the gas producing zone in the deeper gas field. This phenomenon needs to be corrected by subtracting the effect of this fluid migration. The amplitude depends on the density contrast and the depth. Typical values of gravity shifts are ~-2µGal for Mt CO_2 at 800m depth and ~+1µGal for 1Mt water influx at a depth of 2,400m. To put these values into context the standard gravity measurement is 980,000,000µGa (µGal = 10-8 m/s^2).

Gravity measurements are made from instruments deployed by ROVs on to concrete bases across the seafloor. Changes in the gravity field are possible within an accuracy range of 2-3µGal. Changes in sea bed down to 2-3mm are also possible. Inverted gravity data indicates that the CO_2 plume is growing mainly in centre which also ties in evidence from 4D seismic.

Gravity can be used to make quantitative measurements. 9.4Mt CO_2 was injected between the gravity surveys in 2002 and 2013. Inversion of gravity data estimates that 8 ±2Mt CO_2 is stored in the Utsira Formation, if no CO_2 is absorbed in brine. The data shows that CO_2 absorption into brine is happening with a rate of less than 2.7% per year. However, the accuracy is limited by uncertainty in the subtracted signal from water influx to the Ty Formation and the lack of gravity stations over the northern part of the plume in the base survey.

Seismic Discrimination and Mapping of Saturation and Pressure Changes at Snøhvit. Andy Chadwick, BGS

In this example seismic has been used to discriminate between CO_2 saturation and pressure changes within the Snøhvit field. The CO_2 is separated and reinjected into non-producing formations. Originally CO_2 was injected into the Tubåen Formation at a depth of ~2.5km but injection was then switched to the Stø Formation as the pressure increased.

The Tubåen Formation is a faulted reservoir. Initial downhole pressure gauge measurements indicated a pressure difference between injection and fall-off within the reservoir of ~80bars. The initial reservoir pressure was 29MPa at 95°C when injection began. Flow simulations were developed over different distances from the injection point. The model assumed variable porosity / permeability properties and the CO_2 had a tendency to migrate into a lower

section with higher permeability. Pressure simulations conducted over relatively short distances of ~1.6km from the injection point showed the highest increase in pressure. There is a rapid transfer of pressure out to the boundary of the model. This simulation was then compared to simulations with leaky boundaries which show pressure drop off. In this case the model implied a significant flow restriction at a distance of 1.5km. The model simulation closely followed observed pressure data.

Amplitude changes observed from seismic surveys can be tied in with a fault bound compartmentalised reservoir. There is no leakage signal across the east-west trending faults either in amplitude or time-shift indicating a constraint imposed by faults. Fluid migration east or west was still evident. The research team then investigated the frequency spectral composition of the seismic signal which showed higher frequency waveforms closer to the injection point. Lower frequency tuning was dispersed across the fault block. This is consistent with thin layer tuning (related to CO_2 layering close to the injection point) and thicker layer tuning (related to pressure change across the entire reservoir thickness).

InSAR Monitoring of Surface Deformation: Experience and Lessons Learned from CCS Projects Worldwide. Adrian Bohane, TRE Canada

InSAR is a monitoring technique of growing importance for CO_2 storage sites. Operators provide the data from polar orbiting satellites. By recording phase shifts from successive satellite transits it is possible to calculate changes in elevation. Corrections are necessary to remove errors caused by atmospheric interference and other topographic changes such as vegetation growth. Advances in the technology are also becoming evident. It is now possible to repeat satellite records every four days compared with earlier systems that took 24 – 35 days. It is possible to detect changes in elevation at a single point of ≤1mm if there is sufficient data.

Time-lapse history of repeated observations can reveal uplift rates. Examples of >25 inches (63.5cm) have been recorded and correlated with steam injection at a US oil field. At In Salah a more complex pattern of uplift and spreading was detected which indicated movement relative to fault bounded sections of the reservoir. The desert location of this site made it an ideal candidate for InSAR. The technique was applied to Quest which is more heavily vegetated, but with a sufficient number of reference points changes in elevation can be

observed in the future. At Decatur a full three year surveillance cycle from original pre-injection, to injection and then post injection has been recorded. In this case 21 artificial reflectors were used. Accuracy improves with time. In contrast the example, of observations recorded over a pinnacle reef reservoir in Michigan revealed virtually no vertical movement. InSAR has also proved to be an effective method for monitoring vertical fluctuation in a gas storage system between summer and winter. This movement is a key parameter for testing the reservoir's caprock integrity. The reliability and resolution of InSAR could make it a good tool for regulators. It also offers a high cost / benefit ratio.

Discussion - Session 6

The theme of this session and related discussion was making the link between CO_2 saturation and a geophysical response. Controlled-source electromagnetic (CSEM) surveys are claimed to be more sensitive at higher saturation levels of CO_2 but this has yet to be demonstrated. It is also unclear if EM methods can always produce reliable data at sufficient resolution. At sites like Ketzin, with closely spaced wells, the method can complement other techniques; but at other sites low well densities and thin plumes can lead to a lower resolution and mean that it is harder to quantify CO_2 in reservoirs.

There is a broader question as to whether it is necessary to accurately quantify CO_2. Tracking the plume and identifying where the edge is could be of greater significance. Ongoing industry-driven advances in seismic techniques are improving our ability to detect and characterise migration of CO_2. The ability to detect pressure changes within the subsurface is becoming more significant and again seismic techniques are proving very useful in this respect. Quantification of CO_2 saturation especially in thin layers still remains a challenge. The extent of CO_2 saturation can also provide an indication of reservoir capacity as injection continues over several years. EM techniques have been used to detect pre-existing leakage paths in an US oil field. In this example EM forms part of the risk assessment, but it can suffer from vertical resolution. One advantage of EM is that it can screen a large area and then identify areas where the use of other techniques can be more effective for more specific investigation.

Another key question is what measurements are needed to history match models and how can they be refined. A second survey at Goldeneye is planned

to review where CO_2 might migrate to long-term. Once there is sufficient CO_2 in a reservoir it can be used to check and possibly modify models to improve their ability to provide long term predictions. The procedure could be repeated again after three or four years to fine tune the models. Better long-term prediction is fundamental for conformance and risk assessment.

Containment monitoring is also necessary to ensure that risks, such as not exceeding the fracture pressure of caprocks, or wellbores integrity, are checked. In the event that CO_2 does migrate, and reaches a barrier like a fault, simulations will be necessary to predict the effectiveness of the barrier. Modelling can be used to predict the frequency of monitoring that may be necessary. The cost-effectiveness of monitoring has to be assessed in terms of the relevance and benefit of different techniques and what they can deliver. Pressure monitoring is a good example of a relatively low cost option that can be a highly effective tool.

Technology advances can influence data quality. The original 1994 baseline seismic survey at Sleipner is inferior compared to contemporary surveys and further improvements are very likely over the next 30 years. Time-lapse comparisons with inferior baseline data could mean that contemporary surveys are compromised.

With any geophysical observation it is important to be able to tie back a conceptual model to understand the fluid properties of interest including CO_2 movement, for example using seismic observations to test the sensitivity to saturation.

The permeability of sealing layers could have an impact on CO_2 retention. In the case of Sleipner the objective of geophysical investigation was to test the degree of compartmentalisation created by shale layers within the reservoir.

Session 7 - Pressure Monitoring and its Application to Reservoir Management / Leakage detection. Chair: James Craig

Quest Pressure Monitoring. Owain Tucker, Shell

Shell have devised a comprehensive pressure monitoring plan for the Quest project. The reservoir is in the basal Cambrian Mt Simon Sandstone which has multiple seals above the reservoir that act as barriers. Pressure measurements will be made just above the Quest reservoir from an observation well 30m away from the injection well in the Cooking Lake

Formation. The comparatively close proximity of this position will allow early warning of any potential leakage around the casing into higher formations.

Simulations were run to test the rate at which any fluid might leak. The injection rate planned for the site is 1Mt / year or 2,700t /day. A single day's leak might only be 600kg/day and take ~4,000 years before it reached 1Mt.

Pressure buildup at a close distance of 30m can potentially detect an anomaly of ~600kg/day, in the order of kPa (Kilo Pascals). Lower leakage rates of ~10kg/day would equate to a pressure differences ~Pa at close distances. The sensitivity will be related to the formation permeability. At low permeabilities the pressure difference will be higher but the response will be later compared with more permeable formations. Heterogeneity can create uncertainty because geological variation could mean permeability barriers such as shales will influence the time and level of pressure detection. Multiple detection points allow the detection of regional affects within the same formation.

Noise sensitivity is in the order of ~10Pa. The effect of earth tides can be removed by spectral filtering.

The risk assessment defined the monitoring plan. The assessment showed that the most likely, although still extremely unlikely, leak path is the injection well annulus hence the use of observation wells. Pressure gauges have been operating successfully for ~20 years.

Pressure Monitoring, Field Observations and Interpretation Challenges. Sue Hovorka / Seyyed Hosseini, BEG

Pressure based monitoring can be a highly effective, mature technique for monitoring CO_2 injection and leakage detection of either CO_2 or brine. Sensors can be deployed at most depths, the technology is well developed, cost-effective and capable of detecting small differences in pressure. Small leaks can be picked up with time. There are challenges. The noise level needs to be determined to distinguish genuine signals and sensors need to be synchronized. Instrument drift needs to be checked and a regular and reliable power supply is necessary to ensure consistent and accurate measurements. Pressure detectors can be deployed for passive detection above the reservoir in an aquitard and also in an Above Zone Monitoring Interval (AZMI). To investigate reservoir uncertainty a series of model realisations can be

created to determine the level of heterogeneity and therefore well density and distribution for an injection programme. For example at Cranfield pressure records were matched with a geomechanical model. Two wells approximately 30m apart revealed quite distinct pressure response patterns. In one case there was an immediate fall followed by a consistent rise in the AZMI; in the other pressure remained at a relatively consistent level. Temperature monitoring did not match the pressure in the AZMI which led to the deduction that brine leakage was occurring in a distant area.

In an active system pressure monitors are installed in wells in a monitoring zone above the seal. Active monitoring involves an induced pressure response followed by signal analysis in an observation well.

Engineering Aspects of Pressure Monitoring – a Review of the State-of-the-Art. Barry Freifeld, LBNL

Pressure gauge technology is well established and reliable. Piezoresistive or quartz technology sensors have been in existence for 50+ years. Quartz is considered the gold standard for deep well deployments and costs in the range of US$20 – 30,000. 96% work effectively after four years at temperatures of 60-80°C. Electronic components tend to be vulnerable at higher temperatures. Failure rates of 50-60% after four years are more typical at higher temperatures ~175°C and at 200°C technical life expectancy is ~two years. There are technical innovations, for example fibre-optic systems are more suitable for high temperature applications. Memory gauges can record over long periods of time before retrieval which can be a useful fall-back for a surface read out gauge. Acoustic transmission systems have the advantage of avoiding cable connections. Pressure gauges can be highly effective tools for optimising production, pinpointing operation problems, and providing necessary reservoir information for effective control. Pressure data is used to confirm model predictions and demonstrate that the reservoir remains within operation limits set by the regulator.

Pressure was a key monitoring parameter at the Otway project. Pressure was used as a diagnostic parameter to measure permeability. Four gauges were used, two on each downhole deployment. The redundancy was justified because of the necessity to record data without returning to the site. The experiment involved water injection, CO_2 injection, and water extraction from the reservoir. Pressure was measured during each stage to test the fluid

response to each injection. A residual saturation test programme was able to pick up very small changes in pressure. Pressure change measurements caused by tidal earth-moon tides were also detected.

Experience has shown that quartz gauges tend to drift less over time compared with piezoresistive based detectors. Most gauges tend to drift further over time than manufacturers' claims.

Tubing encapsulation of cable is used to increase the life of a gauge deployment, is now possible especially if monitoring is required over several years. A key supplier of quartz based detectors, Quartzdyne, publish failure rates on their website. 14% get returned over a 10 year period. Analysis of returned detectors has improved reliability.

Discussion - Session 7

The Baseline for AZMI at Cranfield has been Complicated due to EOR Operations.

Corrosive formation waters can make wireline logging impractical over periods of several years. Tubing encapsulation was developed to overcome this problem which has enabling long-term monitoring. Gauge reliability has been enhanced by pre and post testing procedures. Some manufacturers test each quartz gauge at a specified operational temperature range before it is deployed for field applications. Operators return failed gauges which can then be examined to determine the cause of failure.

Session 8 - Monitoring Tool Development: Technology R&D for Shallow / Surface Monitoring. Chair: Katherine Romanak

Quantification of Released CO_2 using Acoustic Methods at QICS. Jerry Blackford on behalf of Paul White at the Institute for Sound and Vibration Research, University of Southampton.

Passive acoustic methods can be an effective means for detecting bubbles (and leakage) in a water column but there can be limitations. The background ambient noise level could be a factor from both natural sources such as marine life and anthropogenic sources such as ships. In a shallow sea (<30m) this can be a substantial problem. Detection also depends on a number of factors: the proximity of hydrophones to the source; the bubble size and rate of emission; whether hydrophones are deployed in an array; and the duration of the recording period. For example with one hydrophone a release rate of

10l/minute would be detected at a distance of 1-5m. With an array the range could be extended to 10 – 20m.

Bubble size determines the frequency of the associated noise. Small bubbles have high frequencies and larger bubbles have low frequencies. This relationship could be a means of quantifying the amount of escaping gas. The spectral density of bubble observations can be compared with a model to estimate the quantity of gas. Laboratory based simulations were used to generate a reference condition. Firstly bubbles were generated through a bubble stone and then through an array of needles. The latter configuration produces a consistent pattern of spherical bubbles, whereas the stone produces a variety of shapes.

Bubble observation was an integral part of the QICS release experiment. A bubble model was compared with site observations. Consistent monitoring revealed that the site's 3m tidal range has a big effect on bubble generation. Increased water depth at high tide substantially supressed bubble formation. Bubbles also varied in size (1-2mm – 1-2cm) and shape from spherical to irregular ellipsoid and they can break up and coalesce. Evidence from both experimental and subsea deployment shows that the technique can be used for both observing and possibly quantifying gas emissions from the sea floor[3].

Groundwater Monitoring Network Design for Geologic Carbon Sequestration Sites. Ya-Mei Yang, NETL.

A risk based monitoring strategy for ground water and above-zone monitoring has been developed to deduce leakage pathways. In this case the High Plains Aquifer was selected to simulate leakage from a single well over 200 years. Synthetic data was used to test the system. The probability of leakage was based on the location of a known well and another well whose location was unknown.

Three monitoring parameters pH, TDS and Benzene were modelled. The model outputs were used to determine the mean probability of detection and median probability of detection for these three parameters over one, five and ten years for the two scenarios. TDS is more sensitive compared with

[3] Passive acoustic quantification of gas fluxes during controlled gas release experiments. Benoît J.P. Bergès, Timothy G. Leighton, Paul R. White. Institute of Sound and Vibration Research, University of Southampton, Highfield Campus, Southampton, Hampshire, UK. International Journal of Greenhouse Gas Control 38 (2015) 64–79.

pH. The same exercise was repeated for an unknown well and then tested against monitoring density grids. For the median case it is hard to detect a leak until at least 4 -5 years. TDS is the most sensitive parameter and the first to be detected followed by benzene and pH. TDS is more associated with a brine leak.

The probabilistic design allows a full risk assessment of true leakage events and the simulation of false positives and false negatives. Further modification to the monitoring design, using multiple criteria and background field data to simulate more leakage scenarios, will enhance this methodology.

2D Laser Scanning Absorption Spectroscopy Tool. Jeremy Dobler

GreenLITE is an experimental system to develop a 2D laser scanning absorption spectroscopy tool. The technology relies on two scanning laser spectrometers that can generate a 2D image of CO_2 in the atmosphere. The laser is bounced off a reflector and transmitted at two frequencies. One at the wavelength of the target gas (CO_2) and a reference wavelength that is different. The difference between the absorption spectra is used to detect presence of CO_2.

The transmission and detection system is entirely portable. A 4G network is used to transmit data. Measurements were made over 1km with a precision of over 2ppm. However light snow and rain can attenuate the signal and in some conditions no return signal is possible. 24/7 remote processing is possible.

The system was tested at the Zero Emission Research and Technology (ZERT) site at Montana State University in August 2014. The facility is permitted to release 0.3t of CO_2 per day from a 70m pipe split into six segments. 600 hours of data were recorded over a wide range of conditions. An insitu LiCOR system showed a good agreement with the laser (LiDAR) system. An anomaly was caused by a local manure pile. Some diurnal fluctuation was also observed.

The system was deployed at the Decatur project in February 2015 and ends in September 2015.

Weather conditions can influence results. Line of site observation is essential and may be non-ideal, but the technology is capable of monitoring in real time. The system now being developed has a range of 5km possibly in future

it could operate up to 10km and over an area of 100km^2. Increasing the system's range requires more retro-reflectors and could reduce its sensitivity.

Detecting Leak Locations from Pressure Monitoring Data Assimilation. David Cameron, Stanford University

Leaks can be detected from the assimilation of pressure data long before CO_2 is detected. It is also possible to detect where a leak is occurring but this will depend on the location of the monitoring wells, the number of wells, and the duration of monitoring.

A three layer computational model has been created to simulate leakage, the time it would take to detect, and the influence of well density. In this model nine potential monitoring wells were positioned in an aquifer above the caprock. A heterogeneous reservoir and aquifer were incorporated into the model based on a course grid. The model assumed residual trapping as well as solution trapping. Leakage was simplified to occur through a single grid block, representing an up-scaled leaky well or other leakage mechanism. Five realisations of synthetic pressure data were generated in order to history match simulated field pressure data. There was a good match between the pressure data and the five model simulations.

The amount of time required to accurately locate a leak was then tested. The simulations indicated that around six-to-twelve months of data would be required to detect and locate a leak within one grid block of ~400m of its true location using all nine wells. Additional monitoring time provided no additional benefit. The mass of leaked CO_2 can also be predicted to within around 70% of the true value, using six-twelve months of monitoring data.

To determine how many monitoring wells might be needed to detect a leak, twelve months of pressure data were history matched with simulations of one, two, three, four and nine wells. The results were expressed in terms of the relative proximity of a history-matched versus true leak, expressed in grid block widths, relative to the number of wells. With a single well a leak is evident but only within an area of over 10 grid blocks. With four wells there is a much closer match which is almost as good as a simulation with nine wells over a 12 month period.

In conclusion leakage location with this model is possible with three-four monitoring wells. A reasonable guess for the mass of leaked CO_2 could be

estimated using only one monitoring well, with additional monitoring wells providing marginal benefit. The promising nature of these results warrants further and meticulous investigation.

Discussion – Session 8

Initial results from simulations are encouraging but they need to be tested with further refinement. The next phase of the Stanford modelling work will increase the level of anisotropy and include channelized simulations in both reservoir and monitoring aquifers above caprock. Characterisation based on an actual realisation could improve the predictability of models. This includes using data from both the storage reservoir and the overlying aquifer. The combined use of pressure data in both formations may indicate where a leak may occur and the direction of fluid flow.

The examples from this session have demonstrated that detection methods can be coupled with quantification. Models can also help with the design of smart data monitoring.

Session 9 - Monitoring Tool Development: Technology R&D for Deep Monitoring. Chair: Tom Daley

Aquistore Developments. Kyle Worth, PTRC

Aquistore is a buffer storage for a commercial CO_2 capture plant on Saskpower's Boundary Dam coal fired power plant and active oilfield EOR operations. CO_2 that is not used for EOR is sent to the Aquistore reservoir. Injection started on 16th April 2015. The injection well has been drilled to a depth of 3,396m through the entire section of the basal Cambrian Deadwood Sandstone which is very similar to the Mt Simon Sandstone. An observation well was drilled to a depth of 3,400m into the same formation so that pore pressure conditions can be monitored. The two wells are 150m apart. A casing conveyed pressure sensor showed a slight increase in pressure 100psi (685kPa) when injection stopped demonstrating an immediate pressure effect linked to injection.

The Monitoring, Measurement and Verification (MMV) programme is reviewed daily and the recorded parameters are discussed with the Aquistore operators. The CO_2 volume is influenced by plant operations specifically fluctuations in generation output consequently the monitoring programme has to be modified depending on the quantity of CO_2 injected.

The MMV programme includes 150 fluid sample analyses which began at the start of injection in April. A key objective of this frequency of sampling is to detect first arrival of CO_2 at the observation well. By June 2015 no CO_2 had been detected. Repeat Pulsed Neutron Log (PNL) runs will be conducted until the autumn of 2015. Reservoir simulation has provided guidance on the frequency of repeat logging. Distributed Acoustic Sensing (DAS) and Digital Temperature Sensing (DTS) using fibre optic cables have also been installed.

Other forms of monitoring will include ACROSS seismic surveys which generates seismic waves at the surface which are then detected by a permanent 6.25km^2 array of 620 buried geophones. Micro-seismic monitoring will also be recorded from an array of 51 vertical component geophones at a depth of 20m plus 25 3-component geophone arrays at a depth of 6m. Background seismicity has been recorded since November 2014. These arrays are complemented by three surface broad band seismometers that have been recording since November 2013. There is an additional 5-level down-hole array above the reservoir which has to be re-orientated when it is redeployed for a specific survey. A 20 day passive seismic survey has also been conducted via DAS. No seismic events have been recorded with the exception of background natural seismicity worldwide. There have been some events linked to a large potash mine with a disposal well 200km to the north-east.

Surface monitoring consists of InSAR, GPS, tilt meters, soil gas and ground water monitors. InSAR and GPS should detect any uplift from CO_2 injection, however there is a regional ~5mm subsidence in southern Saskatchewan.

Reservoir modelling suggests ~30kT of CO_2 could be detected within 90 days.

Comparison of Fibre Optic Monitoring with Conventional Geophone Detection Systems at Aquistore. Tom Daley, LBNL

The DAS, which uses a fibre optic sensing system, has been compared with a conventional down-hole geophone recoding array. Comparison of single-mode and multi-mode fibre data sets has also been performed with two different sources: dynamite and vibroseis. The fibre was deployed behind casing. At ~2,867m there was damaged cable but a good signal was received above this depth.

DAS works by interpreting the impact of acoustic waves on a fibre that

continuously interrogates a recorder such as the iDAS, made by Silixa, Ltd. Sampling occurs along each meter of cable at a frequency of ≤10 kHz. The iDAS records fibre strain rate which can be compared to a particle velocity measurement that a geophone would record. This property allows a direct comparison of equivalent units. DAS data has its own noise characteristics. R&D has focussed on noise reduction to improve the signal to noise (S/N) ratio over the entire 2.8km section of the well. Processing enhances signal quality especially for low frequency (<200 Hz) waves. Further work needs to be applied to improve higher frequency signals.

Multi-mode fibre has been deployed for temperature sensing and has shown that good quality data can be recorded for VSPs.

A comparison of DAS and geophone data has shown that a good match can be achieved. However, the noise level is higher in DAS compared to geophone records and therefore more source effort (energy) is required for DAS to get the same S/N ratio recorded by geophones. The advantage of a DAS system is that it can continually record a seismic profile over the entire well as opposed to the limited section covered by geophones. There appears to be little difference between explosive shock wave response and vibroseis records. DAS 3D VSP imaging has also produced good quality results.

DAS appears to be a good cost-benefit match for CO_2 monitoring.

Strain Measurements using Fibre Optics at a Small-Scale Field Experiment. Ziqiu Xue, RITE

Fibre optics can be used for strain measurements. In this example the technology is used to evaluate caprock and wellbore integrity and to monitor fluid injection (CO_2 and water). Properties of two forms of light scattering Rayleigh[4] and Brillouin[5] can be utilised to record and transfer pressure, temperature and strain data. DTS has been installed at Quest.

A DTS / DAS system allows continuous recording which allows data to be recorded throughout injection. This five year R&D programme has included laboratory experiments with sandstone samples contained within a pressure

[4] Rayleigh scattering - The elastic scattering with materials smaller than the wavelength of the light.
[5] Brillouin scattering - Inelastic scattering which occurs when the incident light interfere with sound wave through material.

vessel to test the impact of pressure on the fibre system. Different fibres can be used to detect different parameters. The sandstone core was subdivided between coarse grained and fine grained sections. The fibre mounted around the core was then subject to increasing pressure when the core was compacted (confining pressure) and when pore pressure was increased (expanded). The Rayleigh light scattering response was measured under both conditions. By injecting CO_2 into the core and monitoring the Rayleigh frequency shift the CO_2 migration can be tracked.

The concept was then tested in wellbore at a depth of 300m. The cable was installed behind the casing. A small amount of CO_2 was injected to test the response. The fibre optic system can detect where the strain is occurring which can be directly related to fluid pressure (water injection). Strain measurements were also used to test the cement bond with a caprock. The system was used to detect water extraction from a shallow aquifer which verified its sensitivity to pressure changes.

Session 9 – Discussion

CO_2 delivery to Aquistore has been influenced by commissioning, EOR operations and flexible power generation. Intermittent hydro power generation and grid (transmission line) maintenance can lead to one or two day periodic shut downs. A consistent volume and flow rate has been supplied to the Aquistore site when the power plant has been operational.
By installing fibre optic cable at an approximate mid-point between the rock mass and the casing it is possible to record strain measurements from the formation.

DAS tested over a length of 2.7 km had the same S/N ratio. The system can detect the vertical component of a shear wave.

A crosshole electrical resistivity tomography (ERT) monitoring system was deployed at the Cranfield site for tracking migration of CO_2 plumes at a depth of 3,200m. Monitoring over a five year period was used to evaluate the spatial and temporal evolution of CO_2 plumes between two observation wells. Preliminary processing of first 10-months' worth of data showed that ERT tracked CO_2 saturation changes successfully.

Session 10 - Updates on Monitoring in Current and Planned Demonstration Projects. Chair: Sue Hovorka

CMC Overburden 300m and 500m Depth Release. Don Lawton, University of Calgary

The Containment and Monitoring Institute (CaMI), of CMC Research Institutes, Inc. (CMC), and the University of Calgary are planning two CO_2 release experiments at depths of 300m and 500m at a site in the Canadian province of Alberta. CCS initiatives and related issues are driven by a series of factors. Alberta has the highest carbon emissions of all Canadian provinces that includes daily production of 2-3M barrels from oil sands. There are approximately 450,000 legacy wells within the province and in many of the older wells, only the bottom sections of wells were cemented in addition to surface casing. Evidence from a 2D seismic survey of a former CO_2 EOR operation revealed that even after 60,000t it was not possible to detect the CO_2 partly because 2D seismic data does not recover all scattered energy and a 0.5m thief zone may have dispersed the CO_2 across the top of the reservoir. Thus, the anomaly within the reservoir may have been too thin to detect. Pressure interference of existing hydrocarbon accumulations and other CCS projects also needs to be taken into consideration. Consequently this controlled release experiment will have specific objectives to ensure that secure containment can be demonstrated in future storage sites. The project will include:

- Determination of CO_2 detection thresholds
- Improvement of monitoring technologies and cap rock assessment especially geomechanical properties
- Monitor gas migration at shallow to intermediate depths (~300m) and impacts on groundwater (CO_2 and CH_4)
- Determine the fate of CO_2 (trapping/dissolution)

In addition the project will be used as a field training and research programme. It will also include public outreach.

The test site south-east of Calgary will be monitored over an area of one square kilometre. The lowest release point at 500m is a 23m thick reservoir consisting of three units with a good quality shale cap rock. In contrast, the shallower release point at 300m has a relatively poor seal of mixed coals,

sandstones and shales which has been selected to test how CO_2 may migrate out of a target reservoir. There are thin coal seams which could trap CO_2 but then release CH_4. Consequently the CH_4 flux will be monitored as well as CO_2. The experimental release will be used to measure the detection threshold of CO_2.

The project will also test a new monitoring system based on Muon density tomography which can act as a proxy for density changes induced by the presence of CO_2. Fibre-optic monitoring technologies (DAS, DTS, chem) will also be deployed.

A baseline 3D seismic survey was conducted in 2014. Other characterisation has included a cored 40m interval through the injection zones in the first well drilled. A mobile geochemistry monitoring unit will be deployed to analyse soil gas and ground water at a monitoring well drilled to a depth of 70m. A FLUTe hydrology profiling system will be used to measure the transmissivity distribution with shallow aquifers.

The current goal is to begin injection into the deeper target early in the spring of 2016 once all the monitoring wells have also been drilled in the early winter of 2016.

QICS Marine Controlled Release. Jerry Blackford, PML

The QICS project mimicked a leakage event in a shallow marine environment near Oban on the west coast of Scotland. 4.2t of CO_2 was released over 37 days 11m below the sea floor, and was monitored by several different techniques. On the first day gas propagation to the sea floor via pre-existent pathways had been established. By Day 7 clear chimney structures had appeared in the sediment and by Day 13 the area of reflectivity had increased. After 34 days a narrower chimney, from diffuser to surface, and vigorous venting into water column had become evident.

Quantified flow from observation revealed that ~15% of the gas had entered the water column as gas bubbles. The remaining 85% was not directly measured, but modelling suggests that to achieve the observed chemical changes in the water column approximately 35% of the CO_2 probably seeped from the sea floor in the dissolved phase within the bubble plumes. Longer-term monitoring suggests that a significant proportion of the injected CO_2 may be retained in sediments even after three years. The detection of key

parameters pH and pCO_2 depends on the proximity of the sensor to the release point. Field observation at the QICS site shows that the CO_2 anomalies were only evident within a 20 – 30m radius of the release point.

This background information has been used to develop models of large-scale environmental impacts that might be caused by released CO_2. A number of different scenarios with different assumptions have been generated. In the case of the North Sea modelling shows that strong tidal mixing ensures rapid dispersion and minimises impact. With neap tides there is less mixing and dispersion compared with spring tides. Seasonal fluctuations are also evident. These simulations also show that rapid recovery of chemical perturbations occurs on a timescale of hours or days after a leak has ceased. Modelling has revealed that between ~38 – 90% of the released CO_2 had reached the atmosphere within 90 days via equilibration of dissolved CO_2 (not by direct bubble transfer). Models can also be developed to produce comprehensive baselines and thresholds beyond which $pCO_2$and pH would not normally be exceeded.

Biological impacts were minimal at the site and had fully recovered within three weeks. A more prolonged release could have a more severe impact. QICS has revealed that quantification of leakage will be challenging. Bespoke modelling of baselines and leakage scenarios will aid monitoring strategies and impact assessments.

Ketzin - CO_2 Extraction Experiment. Ben Norden, GFZ

The German experimental CO_2 storage site at Ketzin ceased injection in August 2013. A total of about 67kT of CO_2 were injected over the duration of the storage project. As part of the abandonment phase there has been a CO_2 back production which began in October 2014. The operation was a condition of the original permit. The back-production test presented an opportunity to measure the impact on the reservoir formation. One of the main challenges of the back-production test is the behaviour of the CO_2 in the reservoir and wellbore. The composition of the back-produced brine and gas and the spread of CO_2 at the surface was analysed. Atmospheric monitoring was conducted using Eddy covariance and infrared spectroscopy.

During the final phase of injection in 2013 two-phase CO_2 was injected at 10°C. A 95%/5% CO_2:N_2 mix was also injected. During these final injection

phases Kr and SF6 as well as N_2 were added to the CO_2. A total of 242t of CO_2 and 55m^3 of brine were produced. Daily production was restricted to ~ 800 kg/hr. The tracer gases and N_2 were immediately detected.

The CO_2-related resistivity signature decreased during back-production but increased with brine production. The extraction observations made at the site were within expectation for a pilot scale experiment.

Battelle's CO_2 EOR Storage in a Pinnacle Reef. Neeraj Gupta, Battelle

This CO_2-EOR project is one of a series of Phase III Regional Carbon Sequestration Projects across the USA. This project has reached a large-scale stage to develop the potential for commercial-scale CO_2 storage and EOR. The gas is injection into a pinnacle reef. There are three different types of reef depending on the stage of CO_2 injection and EOR. The pre and post injection monitoring programme includes wireline logging, borehole gravity, fluid sampling, VSP, microseismic and InSAR. The CO_2 flow and pressure / temperature logging is conducted during injection. 600 – 800t CO_2 is injected daily and some is recycled and retained in the reservoir. This project has tracked net retention over time across multiple fields. Since 1996 ~1.5Mt has been retained. Late stage reef pressure response shows slow, long-term decline six months after injection. There have been challenges with matching models with post January 2014 pressure observations. This has been attributed to limited data availability and the heterogeneous reservoir geology. It is not clear whether some pressure equilibration across reef complexes could also be attributed to hydraulic communication beneath these structures. InSAR modelling with reflectors shows no perceptible increase in elevation.

Repeat Pulsed Neutron Capture (PNC) logging is being conducted in multiple monitoring wells. Initial results show an increase in fluid phase constituents and a decrease in gas phase constituents because of the mix of oil and gas. It is possible that the change is due to CH_4 going back into solution and the CO_2 is moving from a gas phase to a super critical liquid. Further logging events may help distinguish phase behavior from fluid saturations. PNC logging is an effective method for verifying containment in the near wellbore environment. It is also inexpensive and easy to deploy.

Gravity surveys are conducted by taking point measurements along the

injection wellbore. The data is then converted to density. Repeat surveys indirectly measure the change in CO_2 saturation. Wellbore data is combined with a CO_2 density model to compile density contrasts induced by CO_2 post-injection. Differences in the δ13C for dissolved carbonate suggest the brine chemistry is altered by the injection of CO_2.

PCOR's Bell Creek CO_2 EOR / Storage. John Hamling / Shaughn Burnison, PCOR

The Plains CO_2 Reduction (PCOR) Partnership is one of the seven Regional Carbon Sequestration Partnerships managed by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL). Lessons learned from monitoring applications were discussed from two years of operational monitoring for the Bell Creek demonstration project, which is studying associated CO_2 storage at a commercial enhanced oil recovery (EOR) project operated by Denbury Onshore LLC. CO_2 injection is ongoing. Since May of 2013, over 1.6Mt of gas has been injected, of which 1.51Mt is retained in the reservoir at current operating conditions after accounting for gas composition and recycle volumes.

This project is employing an integrated approach to site characterization, modelling and simulation, monitoring, and technical risk assessment to guide monitoring strategies and to study CO_2 storage associated with EOR activities. Several challenges exist for understanding associated CO_2 storage compared to traditional storage in deep saline formations (DSFs). These challenges include multiple fluid phases present (CO_2, reservoir gas, water, and oil), operation at near-steady-state pressure, and simultaneous injection and production. The concept of monitoring strategies compared with individual monitoring techniques become key, considering the large geographical area covered by operations. However, considering potential widespread commercial DSF storage, coupled with active reservoir management strategies (i.e., pressure plume control through water production), many of these challenges may not be unique to EOR scenarios.

Near-surface characterization and monitoring present several operational and technical challenges, particularly regarding the high degree of natural annual and inter-annual variability within the environment. Images from near the field illustrated environmental variability, including high rainfall events, blizzards, drought, and wet cycles, all of which add complexity to

understanding monitoring data within these environments. In general, biological activity in the soil increases CO_2 concentrations as summer progresses (wet spring and high temperatures). During late summer and autumn when dry weather dominates (minimal precipitation and cooler temperatures), CO_2 concentrations decrease. These conditions also affect the chemistry of surface waters. Therefore, groundwater monitoring, isotope analysis, monitoring key indicator analytes, and biological process analysis provide improved data reliability for monitoring purposes.

Subsurface monitoring strategies have incorporated a large pulsed-neutron logging (PNL) programme because of the ability to provide both characterization and monitoring information. Time-lapse PNLs have demonstrated the ability to monitor changing fluid and gas saturations within the reservoir in very low salinity environments and have demonstrated the ability to identify breakthrough at production wells in high-permeability zones. This monitoring technique has also confirmed that no migration has occurred through low-permeability confining layers.

The integrated approach is exemplified by the combined use of PNL logs and seismic. PNL logs, combined with simulation results, were used to determine when CO_2 saturations in the reservoir were sufficient to image via seismic methods. Then a 2-D seismic line was acquired to validate that the distribution of the CO_2 in the reservoir could be delineated via time-lapse seismic methods in advance of acquisition of a higher-cost time-lapse 3-D seismic survey, which was employed to provide greater detail. The seismic programme has been useful for locating and delineating features that impact fluid movement within the reservoir such as channel features and permeability barriers.

Field Demonstration of CO_2 Geothermal at the Cranfield Site, Cranfield, Mississippi, USA. Barry Freifeld, LBNL

Cranfield is a field demonstration site for CO_2-EOR, but it has also presented an opportunity to test the use of CO_2 as a heat transfer medium for geothermal energy. A key objective of this experiment was to evaluate the effectiveness of CO_2's thermodynamic properties to extract and transfer heat energy. There are three wells at this site drilled to a depth of 3.2km. Geothermally heated fluid is returned to the surface before it is passed through a heat exchanger and reinjected. The Large compressibility, low viscosity and large expansivity

properties of CO_2, compared with water, are beneficial for heat transfer. While this demonstration used heat exchanges to cool the produced CO_2 a commercial system would use a turbine system to generate power.

Heat output was compared with a geothermal reservoir simulation. A series of simulations were run at different volumes ranging from 5kg/s to 100kg/s and pressures. The simulations have shown that for rates of between 5 and 25kg/s, and wellbore of between 4 and 7 inches (10.16 – 17.78cm), a pressure difference of between ~7.5 and 8.0MPa can be sustained. The results from these simulations reveal strong theoretical thermosiphon properties.

The monitoring programme included a fibre-optic DTS sensor and quartz pressure / temperature sensors. Temperature, fluid density and flow rate were monitored over a three day period. The operation did highlight some technical problems including the formation of CO_2 hydrates and plugged filters.

At the end of this trial it was clear that the thermosiphon could be set up but it was not self-sustaining. Water production was also higher than predicted. Detailed analysis of the data will be required to gain a better understanding of field observations.

Session 10 – Discussion

Multiphase fluid circulation and water slugs were recirculated at the Cranfield site. The experimental results from the circulation experiment now needs to be compared with the simulations. The water / CO_2 mix was measured and provides data on heat transfer, but the model needs to be run with different water / CO_2 ratios. Different fluid combinations need to examine to see how they influence reservoir dynamics.

During the Ketzin extraction experiment there was some brine recovered. The reservoir's heterogeneity is likely to influence the rate of extraction.

Risk assessments of CO_2 venting always assume the most conservative case, although this is unlikely to occur. In one of the fields, CO_2 co-production with oil continued at a fairly consistent rate, even after several months of no new CO_2 injection. This is an indirect indication that the residual CO_2 saturation in the field is relatively low.

Session 11. Post Closure Monitoring: What should be Required for Closure? Chair: Tim Dixon

This session consisted of a series of short summaries from a number of different demonstration sites followed by a panel discussion.

Ketzin. Ben Norden, GFZ

Post closure monitoring at Ketzin consists of surface monitoring and 3D seismic. There is no requirement to monitor wells and by 2018 there will no further monitoring. The wells will be plugged and abandoned. Casing has to be removed which means that geo-electric downhole measurements cannot be continued. However it is important to ensure that all relevant processes have been fully understood for the potential benefit of future injection projects possible in the same basin.

Post closure monitoring should include pressure monitoring of the aquifer, pressure / temperature and down-hole geoelectric techniques. Fibre optic systems are more cost-effective than other methods due to a multiple usage of the downhole cables (e.g. for pressure, temperature, and acoustic sensing). With wellbore closure only soil gas natural flux measurements and ground water sampling from shallow wells will continue.

Mountaineer. Caitlin McNeil, Battelle

The AEP Mountaineer Power Plant CCS project consisted of a pilot-scale 20MW CO_2 Capture and Storage System. Injection took place from October 2009 - May 2011. There were two injection wells and three reservoir monitoring wells. The 18 month injection programme used two reservoirs, the Rose Run Sandstone and the Copper Ridge Dolomite. One of the key objectives of the monitoring programme was the protection of an Underground Source of Drinking Water (USDW). Differential reservoir pressure monitoring, modelling, and plume assessment were combined with soil gas sampling, groundwater analysis and isotope measurements. Plume stability is based on modelled prediction not monitoring, but pressure measurements have been used to validate the model. Part of the validation for this project, stipulated by the West Virginia Department for Environmental Protection, is adherence to the post-injection site care (PISC), which initially was designed around a 20 year post-injection monitoring and closure plan. The Underground Injection Control (UIC) permit and the PISC plan allowed for revisions to the post-injection monitoring period, which has now been updated to reflect

a phased approach of well plugging and abandonment and planned site closure. To date, all regulatory and operational programme requirements and goals under Class V have been met. As part of the revised PISC plan, the site's UIC permit was extended for five years and the two injection wells and one monitoring were plugged in the first phase of site closure.

Cranfield. Sue Hovorka, BEG

The Cranfield CO_2-EOR operation is governed by the Mississippi Oil and Gas Board regulations. The SECARB R&D wells were plugged and abandoned on 5th June 2015 and no further monitoring is required. In an EOR setting, when production ceases no further access is permitted.

If a CO_2 provider/operator had been collecting Green House Gas (GHG) credits what would happen at end of injection? There would be legal questions of access and rights when production had ceased at a commercial EOR site. For instance, monitoring would no longer be permitted for research and verification purposes. There might be a concern over the integrity and access to former production wells in the centre of the structure because of upward migration of CO_2. There is also a question over the impact of future "quaternary" recovery from a field and whether the CO_2 would be retained should more oil be extracted in the future. Oil and gas operators in the USA have no transfer of liability.

Goldeneye. Owain Tucker, Shell

The safest wells post-closure are ones that are properly plugged and abandoned. Experimental evidence shows that CO_2 would take 30,000 years to diffuse completely into a Portland cement plug, and the carbonation process makes it less permeable. Oil and gas fields can have complex fluid compositions including H_2S so why should a CO_2 storage site be any different? However, operators need to be certain that shareholders are not exposed to risk once a site is closed. At Goldeneye the proposal is that there will be post-injection seismic and surface monitoring to check that no problems or impacts have occurred with the storage after injection has ceased and then five years later. The site would then be transferred to a competent authority.

Tomakomai. Jun Kita, RITE

The Tomakomai CCS demonstration project will inject CO_2 from 2016 to 2018. The permit will be renewed every five years. The measures for

maintenance and/or closure of the injection wells require monitoring to ensure: conformance of the reservoir pore pressure; containment of CO_2 distribution within the reservoir; and contingency to avoid adverse impacts on the marine environment. There are important considerations that need to be addressed for post-closure stewardship of CCS sites because the post-closure conditions are not covered by legislation. These include:

- The length of time to continue monitoring.
- When should responsibility be transferred to the government or another entity?
- The level of financial compensation for the affected individuals or entities who might have been affected by leakage.

ROAD. Philippe Steeghs, TNO

For the ROAD project the closure plan is based on the risk assessment for the project. Transfer and closure is permitted if all conditions in the plan have been met. The post-injection monitoring period is 20 years but it may be less if the Competent Authority is satisfied. After injection operations have ceased, the monitoring plan recognizes four post-injection phases. First, while the reservoir is still accessible, there will be a (one-year) period of observation to verify that the reservoir is moving towards a stable condition. Then the well will be plugged and monitoring will focus on integrity of the well, and if the quality of the seal is found to be sufficient, the well is sealed and the monitoring is continued in the post-abandonment phase. Finally, after the site is transferred to a Competent Authority any developments in the reservoir will be followed periodically. However, as post-transfer monitoring is the responsibility of the Competent Authority the monitoring program does not address this phase. However, it can be expected that environmental monitoring activities will continue into this phase.

Session 11 – Discussion

The containment of CO_2 needs to be successfully demonstrated but in certain circumstances, for example, the migration of a thin CO_2 plume, detection by seismic might not be possible. Good site characterisation is therefore essential to understand the extent of heterogeneity within a reservoir and the level of CO_2 saturation, so that long-term predictions can be made with confidence. If competent caprock is present, and can be demonstrated to be

an effective seal, then the trapping mechanism is less important because the CO_2 is retained. A risk assessment should identify risks, and their magnitude, at a specific site and that approach should determine how risks are addressed.

There are stringent demands being placed on CCS such as no change in ground water. This view could be regarded as an acceptable standard or too demanding. As a new industry more demanding regulations and monitoring is inevitable. There is an understandably cautious approach adopted by regulators towards large-scale demonstration projects, particularly if key resources like drinking water need to be protected. Operators have to implement monitoring programmes and risk assessments to detect and avert leakage even if there is a very low probability of leakage occurring.

Research techniques and advances in technology might encourage regulators to demand more monitoring without understanding whether it is necessity. The research community needs to explain the distinction between monitoring for compliance and the use of research and development (R&D) for new techniques that need to be evaluated before eventual deployment. R&D also determines the sensitivity of different techniques and whether they can make a relevant contribution to any monitoring programme. There is a tendency to implement detailed monitoring and characterisation of new projects because they are first of a kind, but future commercial projects will benefit.

Communication between operators and regulators has an important role. Parameters such as the level of exposure that is anticipated compared with an observed baseline needs to be conveyed. The risks also need to be put into perspective especially for the general public.

Session 12 - Leakage Failure Scenarios – How to Detect Them. Group Exercise. Chair: Sue Hovorka

In this session four different hypothetical characterization and injection scenarios were divided between the delegates. In each case the teams were asked to devise a monitoring strategy. Each team was then presented with a "what happened next" scenario with a leak present. A team member then presented the conclusions most notably the comparison between the predicted leakage pathway and the "actual" pathway.

Session 13 - Conclusions, Further Research Areas and Recommendations. Chairs: Tom Daley, Tim Dixon, Charles Jenkins

Key Messages and Conclusions

- Pressure monitoring is a prime tool for interpretation but there is scope for further refinement. Pressure signals are dependent on geology and good quality signals can be detected if natural conditions allow. There is great potential for pressure based monitoring but noise levels and interpretation remain as challenges.
- Pressure monitoring has the advantage of large area coverage within reservoirs. Above Zone Monitoring Intervals (AZMIs), above storage reservoirs, are the best locations to deploy sensors for leak detection if models show that such leakage creates a sufficient pressure difference. The pressure monitoring in the AZMI can potentially locate leak pathways before CO_2 leakage occurs. Assimilation of pressure data can be used to predict the volume of leakage expected along the pathway. The approach will not be effective in a case like Sleipner because the pressure difference between the reservoir and the AZMI is so low.
- Risk assessment should identify highest areas of risk and therefore guide the design of a monitoring programme. For example in the Goldeneye project leakage via wellbores is the highest risk so monitoring is focussed in this area.
- Pressure monitoring can be an effective means of detecting anomalies such as leaks especially if used in combination with other measurements.
- There is potential in DAS and permanent source seismics as monitoring techniques, but further development is required. Various field deployments will probably be precursors of improvements in seismic imaging.
- There is a requirement for more geomechanical analysis and models to use monitoring data. In some cases InSAR monitoring has revealed surface uplift within reservoirs that is directly related to an increase of pressure within a reservoir as at In Salah. In other cases, for example Decatur and in Michigan pinnacle reefs, no uplift is observed. Pressure dissipation could be the reason. Variable sensitivity in different regions and surface conditions is also a factor.

- The lesson from CO_2-EOR and upcoming CCS projects (ROAD, Peterhead, Quest) is that monitoring plans can be quite simple but the interpretation and connection with regulatory requirements could be quicker and clearer.
- Passive seismic may be needed more as the understanding of induced seismicity becomes more important, and it can be combined with opportunities presented by ambient noise recording and virtual source seismic.
- Should there always be a concerted effort to detect leaks or should leaks develop until they are detected?
- The effort directed into leakage detection might be more effective if it was initiated once evidence of a leak occurred.
- A key message is that potential leakage to surface is very low with the exception of old wellbores. Consequently, it would be more effective to concentrate on leakage from reservoirs rather than at or near the surface.
- CO_2 extraction from storage has been measured at Ketzin. A preliminary field test to evaluate the potential of CO_2 as a thermal transfer medium for geothermal energy, including a controlled release of CO_2, was conducted at Cranfield.
- Controlled release experiments in a marine environment have demonstrated that leak detection is possible. Initial investigation suggests that the potential quantification of released CO_2, using acoustic monitoring of bubbles, is possible.
- Monitoring at various demonstration sites has shown that Conformance, Containment and Contingency requirements of regulations (London Protocol, EU CCS Directive, US EPA Class VI) has been met.
- Spectral partition can be used to show CO_2 distribution and pressure variation. Seismic Interpretation of the spectral content from the Snøhvit Field is a good example of this approach.
- Time lapse gravity has been used effectively at Sleipner. The technique is highly sensitive, differences of 2-3 µGal can be detected and related directly to the CO_2 plume.
- Injection started at the Aquistore demonstration project on 16th April 2015.

Areas for Further Research

- There is a lack of knowledge of CO_2-EOR operations and CO_2 accounting within the CCS community.
- The link between shallow monitoring and quantitative risk assessment needs to be developed, however the effort required and what should be done needs to be refined.
- The application of pressure tomography to CO_2 storage.
- Accounting of stored CO_2 for regulators is under-developed in some regions.
- Communication of risk could be improved and is not always put into context. For example a minor leak of 600kg/day when 2,600t/day is being injection is only ~0.02%.
- Finding the most cost-effective combination of geophysical monitoring at any given site, and the development of an effective approach beyond the demonstration stage, has yet to be determined.

Recommendations

- Share expertise with oil industry groups like SPE and the EOR fraternity especially the management and accounting of CO_2 in the subsurface.
- Spread the experience and understanding of induced seismicity to a wider audience outside the US.
- Improve understanding of near-surface monitoring and what additional advances need to be made in monitoring and modelling.
- Identify R&D to improve the understanding of the link between shallow monitoring and quantitative risk assessment.
- Develop a better understanding of AZMI pressure monitoring and its relationship to geomechanics.
- Develop initiatives with regulators to encourage regular dialogue with them.
- Include a carbon accounting case study in a future network meeting.
- The development of a traffic-light system for managing the impact of induced seismicity, as part of best practice procedures and protocol development for induced seismicity in CO_2 storage.

- Induced seismicity needs to be included in risk assessment.
- Run future meetings with pre-set objectives that are developed throughout the course of the meeting.
- Allow more discussion time and set aside time dedicated to poster sessions.
- The Monitoring tool is useful for novices but a bit out of date. Its continued use was endorsed by the meeting.