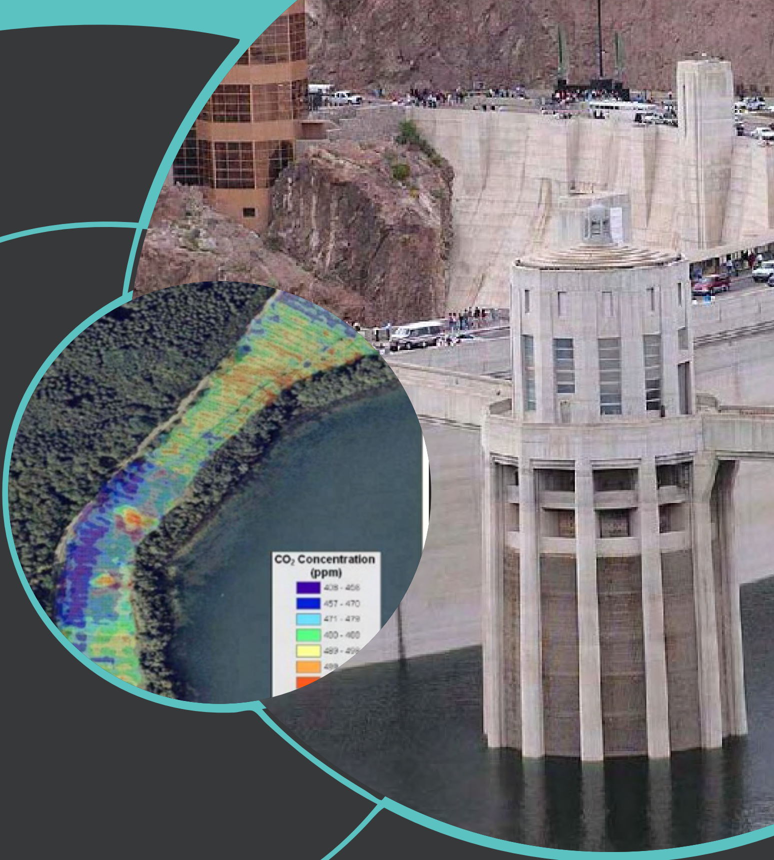
Evaluating technology options to mitigate greenhouse gas emissions



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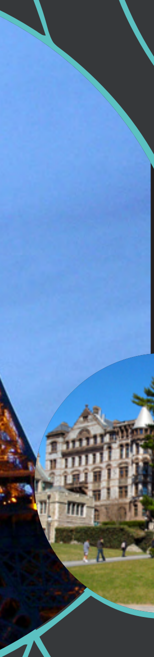

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Contents

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 second Overview Book produced at the end of 2011. It draws together the overviews and executive summaries written by IEAGHG over the course of 2012, 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.

2012-03 EMISSIONS OF SUBSTANCES OTHER THAN CO_2 FROM POWER PLANTS WITH CCS

Introduction

The emissions of CO_2 from power plants equipped with carbon dioxide capture systems are reduced by upwards of 85% compared to equivalent plants without capture. However the full environmental impact of a plant fitted with CO_2 capture will depend also on what changes are induced in emissions of other substances in gaseous, liquid and solid form. Furthermore due to the increase in fuel and chemicals consumption typical for a CCS plant emissions due to the "upstream" and "downstream" processes and particularly those associated with increased fuel use, will also increase. Both these effects need to be taken into account if the technology is to be assessed on a life cycle basis. This study focuses only on the changes which are to be expected in the direct emissions, discharges and solid wastes of substances other than CO_2 from within the boundary of power plants fitted with CO_2 capture.

Approach

The study was awarded to TNO, The Netherlands on the basis of competitive tender. The assessment covers the main technologies for CO_2 capture for coal and natural gas fired systems and includes the three main technology routes of post, pre and oxy combustion. Estimation of emissions and wastes is complex and accurate prediction of the amounts and composition of some categories of waste at the design stage is not possible. Hence TNO adopted two approaches in making their estimations. The first was to base estimates on the literature references which include both theoretical predictions and actual measurements from pilot, demonstration and commercial units. The second approach was to use modeling to come up with an estimate of emissions and wastes. The results would thus show the degree of variation and hence indicate areas of uncertainty and would also by comparison of the two approaches indicate where undue optimism or pessimism might prevail in the modeling methods being used for design of CCS plants. The modeling approach also relies on data extracted from literature, typically for estimating the removal efficiency of the unit operations employed in CCS. A clear distinction is made between these two approachs. The literature based approach is taking plant emission values as reported in literature. The modeling synthesises the values for each of the selected processes based on estimates of the performance of the various unit operations which make up the complete power plant.

A part of the literature based estimation was to make appropriate allowances for variations in baseline assumptions for the various plants in the references. This "harmonisation" methodology was applied to take account of variations in sulphur content of coals and the percentage capture of CO_2 where solvent based absorption processes were applied. This process thus attempts to ensure that "like for like" situations are being compared. All the raw and harmonised data from the literature was assembled in a database which was used to make statistical estimations of the most likely changes in emissions and wastes and also the ranges which could be expected.

Results and Discussion

General

Baseline data was collected for three types of power plant without capture:-

- Ultra Supercritical (USC) Pulverized Coal (PC) fired steam plant,
- Coal fired integrated gasification and combined cycle power plant (IGCC),
- Natural gas fired combined cycle power plant (NGCC).

Data for 4 CCS plants for comparison with these baselines was collected for:-

- USC PC plant with post combustion capture using an MEA solvent,
- Oxyfueled USC PC plant using the CO_2 separation and clean up process of Air Products,
- IGCC plant adapted for CO_2 capture using Selexol to recover the CO_2
- NGCC plant fitted with post combustion capture again using MEA solvent.

A total of 37 references were found in the literature and these were used to populate a database of 176 different cases. However complete datasets could not be generated for all of these cases as the amount of information varied quite widely. This data formed the basis for estimation of emissions using the harmonisation approach. It is thus expected to yield "average" values based on current experience. The range of values will also give some indication of the best and worst which might be expected and hence also represents the full range of technologies.

In contrast the modelling method of estimation used a design approach to estimating emissions and for this the researchers chose generally to model

"Best Available Technology" (BAT). In practice they have chosen, what is considered to be state of the art versions of processes, which are considered to be economically applicable and thus may have not have explored the extremes of possible performance. Hence it may be more accurate to describe the choice as Best Available Technology Not Entailing Excessive Cost (BATNEEC)

The results of the analysis finally allow comparison of emissions and wastes against baseline for 4 technologies.

- Coal fired USC Post and oxy-combustion against coal fired USC,
- Pre-combustion IGCC against conventional IGCC
- Post combustion NGCC against conventional NGCC.

For the coal fired plants with and without post combustion the baseline the plants included SOx control using wet limestone flue gas desulphurization and NO_x emissions control using overfire air, low NO_x burners and Selective Catalystic Reduction (SCR). For the NGCC cases low NO_x burners and SCR were included.

The emissions and wastes which are compared include (where data is available):

Gaseous emissions

Acid gases

CO_2

SOx (Broken down to SO_2 and SO_3)

NOx (Broken down in to NO and NO_2)

HCL

HF

CO

Trace elements

Mercury (Hg^0,Hg_2+,Hg(p))

Trace metals (As,Cd,Cr,Co,Pb,MN,Ni,Se,Zn,Cu and by class 1,2 3)

Other compounds

Ammonia

Chemical degradation products (NB subject of separate report)

VOC's

Particulates

PM

PM_{10}

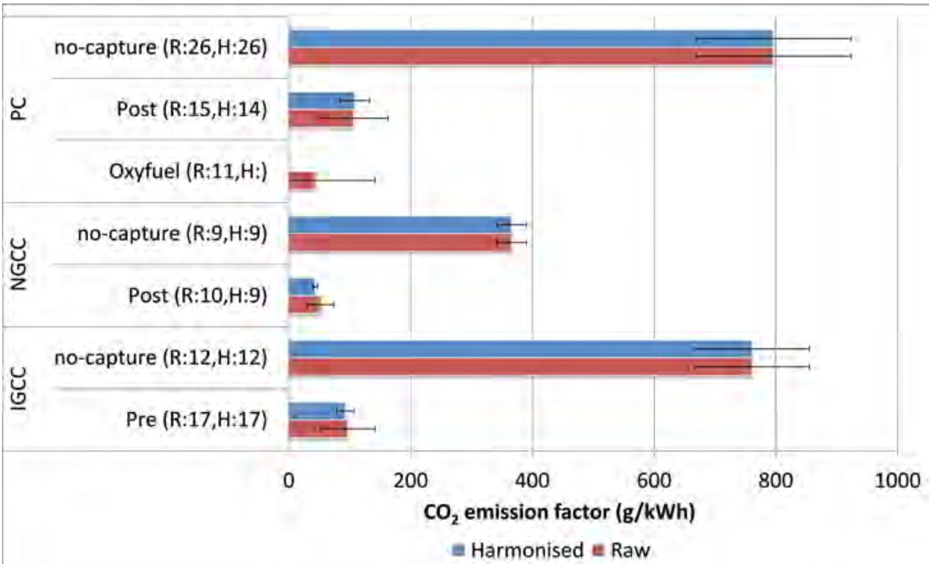
Solid and liquid waste categories

- Gypsum
- Particulates from ESP
- Furnace bottom ash/
- Coarse slag
- Fly ash /
- Fine slag
- Mill rejects
- Sludges from WWT
- Reclaimer waste
- Activated carbon
- Waste water

Assessment results for each type of emission

CO_2 emissions

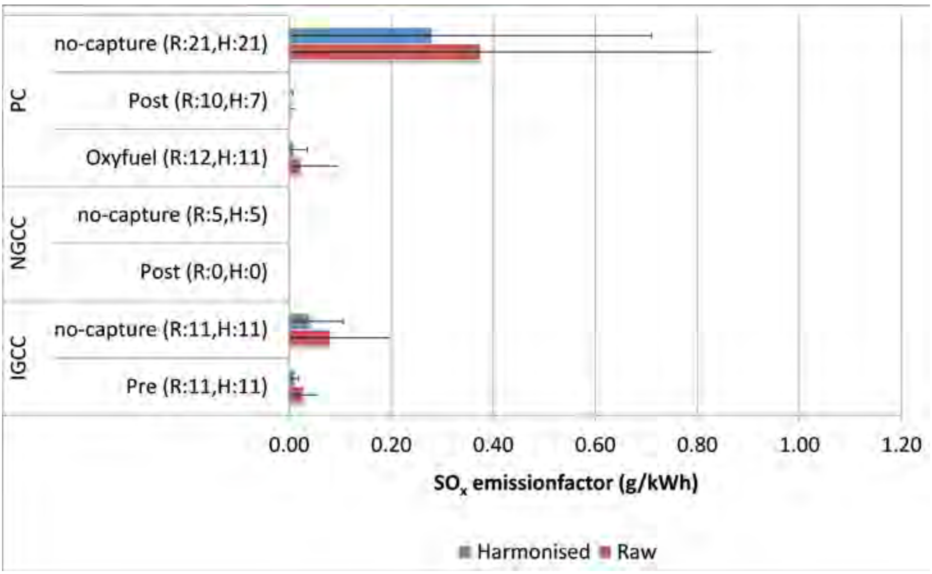
The chart to the right summarises the emissions levels of CO_2 found from the literature and shows the raw as well as harmonised data. The red bar shows the average of the raw data and the blue bar the average after harmonisation. The black lines indicate the range of data upon which the average is based. It is noticeable that the harmonisation process reduces the spread of data for



Harmonised v Raw CO_2 emission factors in g/kWh net electricity produced the capture cases considerably. This indicates that the variations in capture rate and fuel sulphur content for which compensation was applied did indeed widen the range of reported emissions.

Acid gas emissions other than CO_2

Both the reference data base and the modeling method suggest almost complete elimination of gaseous sulphur compound emissions as a result of adding either post or oxy combustion CCS to pulverised coal steam power plant. IGCC has only modeling results which suggest a reduction of only about 85% although in principle the sulphur recovery plant responsible for the emissions can be designed to reduce them further. Also for the case of NGCC only modeling results are available. Sulphur emissions of the base case are already very low because of the low sulphur content of natural gas. The model shows virtually all sulphur emissions eliminated. The chart below illustrates the results from the harmonization assessment. Note the rather wide range of sulphur emissions reported in the literature from plants without capture.

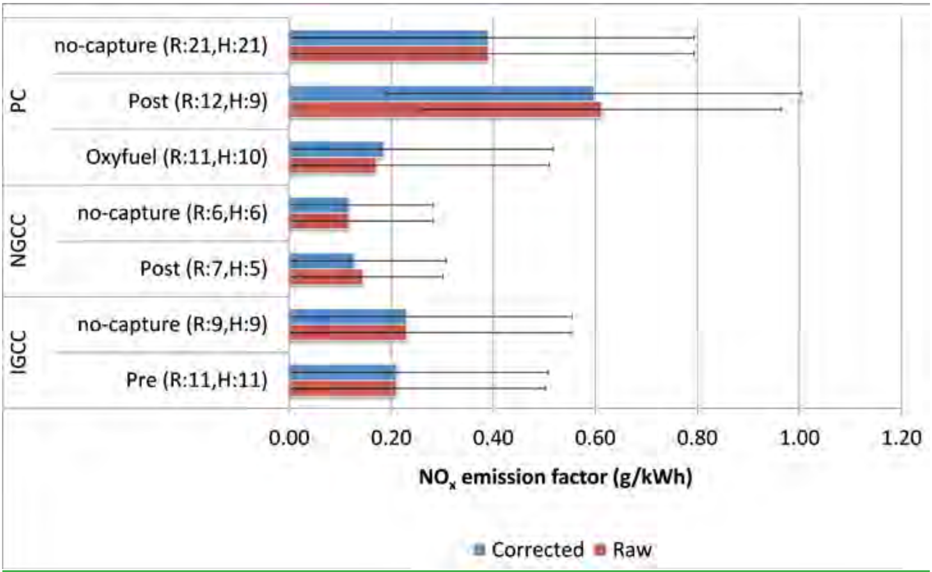


Harmonised v Raw SOx emissions as g/kWh net electricity produced

Nitrogen oxides consist mainly of NO with some N_2O. Both reference data and models suggest that NO will not be removed by addition of post combustion CCS and thus NOx emissions are expected to increase slightly roughly in proportion to the increased fuel use. Average values from the literature show an increase somewhat in excess of this. No explanation was found for this result. Modelling suggests that some N_2O will be removed by the absorption unit but as most of the NOx is in the form of NO there will be an overall increase.

No references were found for IGCC NOx emissions but modeling suggests no significant change. The emissions are solely due to NOx formed in the gas turbine. Fuel efficiency is reduced which would lead to increased emissions. The modelling is thus assuming some advances in NOx control for hydrogen burning as distinct to syngas burning gas turbines which may or may not materialise. Likewise NOx emissions were not evaluated for Oxy-combustion. Expert reviewers are expecting up to 99% destruction of Nitrogen oxides in the reactors of the clean up process. However any NO which passes into the cryogenic separation section will partition into the inerts vent stream and thus be emitted.

For oxy combustion modeling currently suggests that NOx emissions will be eliminated. However the literature shows wide variation and suggests only a partial reduction. The oxy combustion CO_2 clean up process has undergone rapid development in the last few years. The harmonised reference data is using averages and the data shows variations from complete to limited reduction. In this case the modeling result is probably more reliable. The chart below shows the harmonisation results based on literature references. Notice the NOx figures for oxycombustion do not reflect the current expectations of very low levels.



Harmonised v Raw NOx emissions as g/kWh net electricity produced

HCl, HF and CO emissions reductions were considered only through modeling and only for coal fired USC PC steam systems. The strongly acidic components HCl and HF are predicted to be reduced by 95% in the case of post combustion and to be completely eliminated in oxy combustion CCS systems. CO is not expected to be absorbed in post combustion. The report gives no evaluation of the CO emissions from oxycombustion. However expert reviewers suggest that two light gases CO and NO will partition into the vent stream in the cold CO_2 clean up process and thus CO emissions will remain roughly the same perhaps increasing due to the additional fuel usage. However experts also suggest that by including a catalyst in the vent stream after it has been heated prior to expansion down to atmospheric pressure any remaining CO might be oxidized.

The study shows CO emissions from IGCC with and without CCS as virtually the same based on literature reference. However given that in CCS nearly all CO is removed expert reviewers questioned this.

Trace elements

Trace elements usually encountered are the metals Hg, As, Cd, Cr, Co, Pb, Mn, Ni, Se, Sb, Zn, Cu.These are divided into three classes according to the way they tend to partition between gaseous emission and solid waste. Hg and Se are considered volatile and fall into Class 3. As, Cd, Sb and Pb are semi-volatile falling into Class 2 and the rest are considered non volatile and fall into Class 1.

Information on the removal of these components by the CCS processes is limited. For those CCS systems which pass flue gas through a solvent system a conservative assumption that only 20% of classes 1 and 2 would be removed has been made. This is roughly equivalent to the increased fuel usage so that trace metal emissions in these classes would be unchanged. However given that these materials tend to partition to the solid phase it might be expected that the additional contacting in absorber columns and direct contact coolers might make bigger reductions. In order to verify this it will be necessary to make measurements of these components in flue gases from CCS plants.

The effect of MEA scrubbing on mercury depends on the oxidation state. There is evidence that Hg2+ is absorbed in MEA and in modeling a removal of 76% has been assumed. Elemental mercury is not chemically absorbed in MEA solutions and a low reduction factor of only 8% has been assumed in the modeling for this study. Since about ¾ of the mercury is typically present as elemental mercury there is only a small reduction in emission concentration in the absorber which will be offset by the increased flow. Again more accurate measurements of emissions and build up in the solvent are needed to determine the partition effect.

Particulate Matter

Particulate matter is reduced by several processes within power plants. The final reductions are mainly achieved in the Electrostatic Precipitator (ESP) if fitted and the Flue Gas Desulphurisation unit (FGD) if fitted. Without these units reliance is placed on drop out in the boiler at various points and removal by filtration. The literature gives a confusing view of how particulate emissions will be affected suggesting an increase whereas modeling assumes that where an absorption unit or direct contact cooler provides additional liquid gas contacting a reduction of 50% of particulates would occur. Thus even allowing for the increased fuel use there should be a net reduction in particulate emissions. The increased particulate emission levels for CCS processes reported in the literature thus need to be treated with caution as no explanation for the increase is forthcoming. There is thus a need to better understand why the literature results are an average higher and also for a better measurement of the effect of additional gas liquid contacting equipment on particulate emissions. Oxy-combustion should exhibit zero particulate emissions since the only remaining gaseous stream is a small flow of inerts from the CO_2 clean up unit which is unlikely to contain particulates as it will have passed through several gas liquid contacts in the clean up reactors and the cold box. Literature also shows almost but not quite complete elimination of particulate emissions from oxy-combustion plants.

Other substances

Ammonia is emitted from plants without capture if SCR is installed and there is any ammonia slippage. The harmonised data shows a small average ammonia emission for pulverised coal plants without capture. The data for NGCC plants without capture suggests very low average levels probably because it is less common to add SCR to such plants. Ammonia is a volatile degradation product of plants using MEA (and also for plants using other amines). The literature thus suggests a substantial increase in Ammonia emissions from Coal fired USC CCS plants. No data is available for NGCC plants with post combustion capture but similar effects could be expected. Ammonia emissions were not estimated by modeling and this and other MEA degradation products is being addressed in a separate IEAGHG study on chemical emissions from post combustion capture plants. Ammonia emission from IGCC plant were not evaluated but expert reviewers suggest that these are absent since they are already removed upstream of the acid gas removal system in the wet scrubbing system of such plants.

Assessment results for each type of solid and liquid waste

For the coal fired cases the amount of solid waste increases more or less in line with the increased fuel usage. Sludge from waste water treatment increases similarly. Gypsum production in the post combustion capture case may increases slightly more than this due to deeper sulphur removal. This depends on whether the FGD is configured to produce lower SOx levels or whether all of the reduction needed to meet Amine scrubbing inlet specifications is achieved by caustic scrubbing or similar. On the other hand there is no gypsum byproduct in oxy-combustion since the SO_2 is removed as Sulphuric acid in solution. NGCC does not produce any ash wastes.

Reclaimer waste and a small amount of spent activated carbon from solvent clean up are two new wastes emanating from post combustion plants fueled either with gas or coal.

Oxycombustion plants have to remove mercury using mercury guard beds which may use activated carbon or pre-sulphided adsorbent in order to protect the aluminium cold box in the CO_2 clean up unit.These materials may also have to be used in base line coal and IGCC plants to reduce mercury emissions to meet tightening regulations . However no data on the quantities of this waste bed material is reported in this study.

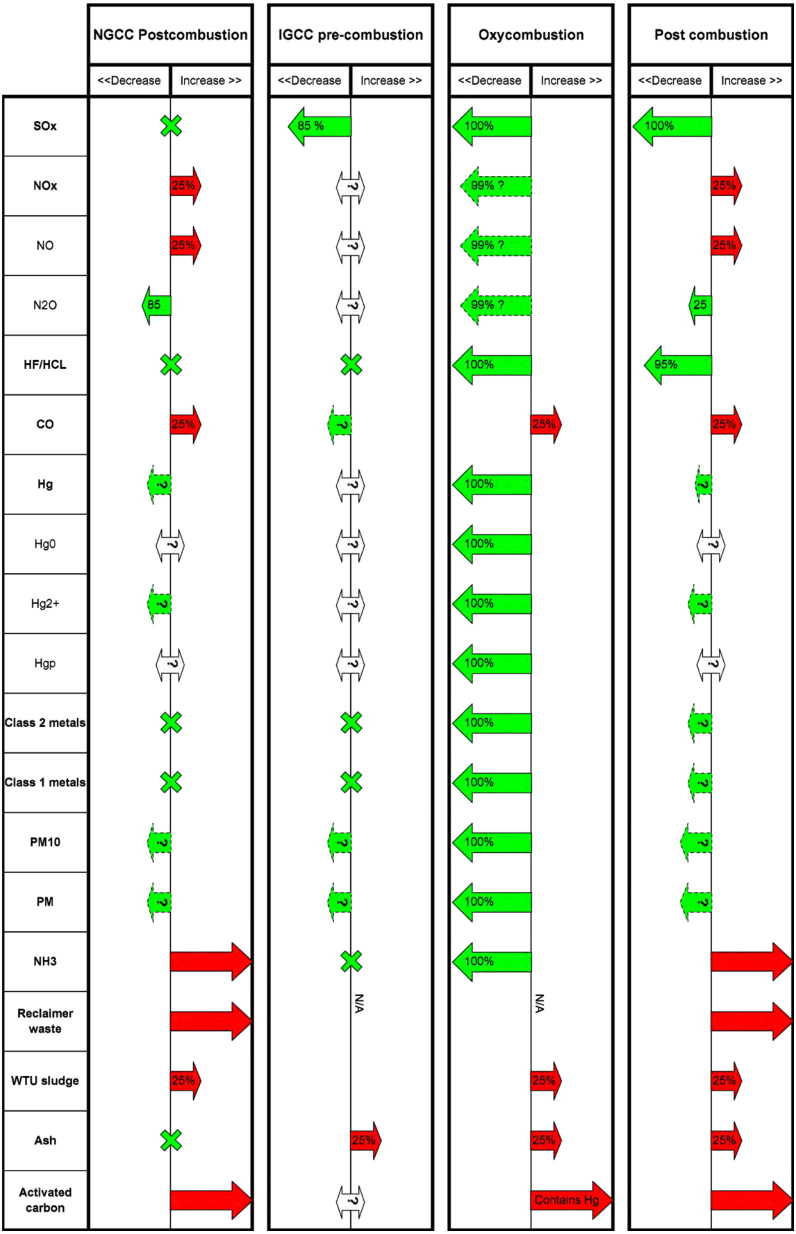
There is a significant increase in the amount of waste water production from post combustion coal plant due to the condensation of water out of the flue gases. No information was included in the study on the waste water streams expected from oxy-combustion. Experts pointed out that oxy-combustion process will produce a waste water stream containing sulphuric and nitric acids along with some mercury. Before discharge this stream will be treated for example by neutralization with caustic soda and for mercury extraction. Development of the clean up process for this stream is ongoing.

Overview of changes

Full details of the expected emission levels evaluated by the two techniques, (modeling and harmonization of figures published in literature) with and without CCS are included in the main report. Set out below in the form of a pictorial chart is an over view of the changes to emissions and wastes which each of the capture technologies will cause when applied to the baseline power plants. The indication is of the relative magnitude of emissions and wastes and does not indicate the actual size of the emissions. For some categories of emission the baseline plant already has essentially zero emissions and this is indicated by a green cross where this is the case A distinction is made between changes which are certain and those which are not. The arrows indicating the change have a dotted outline/contain a

"?" symbol where there is currently uncertainty. Further work is needed to clarify all changes which are shown as uncertain. Most notable is the almost complete elimination of gaseous emission in the oxy-combustion process. Post combustion processes lower most emissions substantially but the exact extent is still subject to uncertainty. However there are small increases in NO and an introduction of a potentially substantial ammonia emission. There are also potentially other chemical emissions which are subject of a separate report. The extent of the ammonia emission is dependent on the additional scrubbing technology which is eventually deployed downstream amine absorbers.

The most notable change in solid/liquid wastes is the appearance of a new liquid waste from post combustion processes in the form of a stream of degraded solvent from the amine reclaimer. For oxy-combustion a new water stream containing sulphates and nitrates possibly containing some mercury is expected to be produced (not shown on the chart). Exactly how benign this stream can be made is not yet known. Ash from all of the coal fired processes increases in line with the increased fuel consumption.



Changes in emissions and wastes when CCS is applied

Expert reviewer's comments

Reviewers raised a number of questions as to the completeness of the literature survey particularly in respect of data on IGCC and oxy-combustion processes. Some also considered that the treatment of these processes was a lot less thorough than for the pulverized coal plants. Reviewers also felt that there was far more emphasis on gaseous emissions and that the treatment of solid and liquid wastes should be more extensive. Most reviewers recommended improvements to make the study clearer and more easy to read. These comments were taken on board and a revision to address them as far as possible was undertaken.

Some reviewers challenged the method used to harmonise CO_2 capture percentage and the authors modified this in the final version. The Oxy-combustion process has an inherent high capture percentage and was not harmonized on this attribute. Reviewers also pointed out where figures quoted seemed anomalous or incorrect and the authors reviewed and responded to these challenges in the final report. Some of these issues might be resolved if the authors database was available as part of the report. However their database forms part of their proprietary information and cannot be made generally available.

Some reviewers felt that too much emphasis was given to description of the methodologies rather than comparison of the results and this too was addressed. Despite these criticisms of the draft report most reviewers felt that the report was an extremely valuable synthesis of the available information on the effects of carbon dioxide capture processes on emissions and wastes of substances other than CO_2.

Conclusions

This report goes some way to quantify the changes which CCS will make in emissions and wastes other than CO_2 from power plant. A number of areas of uncertainty are revealed either due to lack of measurements or because processes are not yet fully developed.CCS processes in general offer reductions in gaseous emissions of most components but there are exceptions where small increases can be expected mainly related to increased fuel consumption. However solid and liquid wastes for all the processes show some increases and in some cases changes in nature.

Recommendations

Further work needs to be done on all those areas flagged in the chart as being in some way uncertain. This work may need to be in the form of many more in depth measurement campaigns on pilot and demonstration capture plants but also some of the processes used to reduce or eliminate unwanted emissions and wastes need further development. Where gaseous emissions are highlighted as potentially increasing, attention needs to be given to the process selection and design to establish whether the increases can be mitigated or reversed. This work will need to be carried out by industry and research institutions and the role of IEAGHG should at present be limited to encouraging this work to be done, published in appropriate journals and presented at conferences and meetings.

2012-06 OPERATING FLEXIBILITY OF POWER PLANTS WITH CCS

Background to the Study

Most assessments undertaken by IEAGHG and others have assumed that power plants with CCS will operate at base load. It is now becoming clear that in many cases CCS plants will need to be able to operate flexibly because of the variability of electricity demand, increased use of variable renewable energy sources such as wind and solar and poor flexibility of some other low-CO_2 generation technologies such as nuclear. However, relatively little work has so far been published on this subject.

IEAGHG has commissioned Foster Wheeler Italiana to carry out a study to review the operating flexibility of the current leading power generation technologies with CCS and to assess performance and costs of some techniques for improving flexibility. This overview of the report was written by IEAGHG.

Scope of Work

The study assesses the flexibility, performance and costs of several examples of power plants with CCS but it is recognised that there are many other potential design options with different degrees of flexibility. The study covers the following leading technologies for power generation with CCS:

- Ultra-supercritical pulverised coal (USC-PC) with post combustion capture using solvent scrubbing,
- Natural gas combined cycle (NGCC) with post combustion capture using solvent scrubbing,
- Integrated coal gasification combined cycle (IGCC) with pre-combustion solvent scrubbing,
- Pulverised coal oxy-combustion

The study makes use of baseline plant performance and cost data from earlier IEAGHG studies, taking into account cost inflation that has occurred since those studies were undertaken.

The following techniques for improving flexibility and increasing peak power output were assessed:

- Turning off CO_2 capture,
- Storage of CO_2 capture solvent,
- Storage of liquid oxygen,
- Storage of hydrogen,
- Storage of CO_2 or solvent to provide a constant flow of CO_2 to transport and storage.

The report also includes a brief overview of energy storage techniques for large scale electricity generation.

Results and Discussion

Operating flexibility of power plants without CCS

Typical flexibilities of power plants without CCS are summarised in Table 1. It should be noted that actual flexibilities of power plants depend on the plant design and the preferences of vendors and operators.

	NGCC	USC-PC	IGCC
Minimum load, %	40-50	30	50
Hot start-up time, hours	0.75-1	1.5-2.5	6-8
Cold start-up time, hours	3	6-7	80-100
Ramp rate, % per minute	4-6 (40-85% load) 2-3 (85-100% load)	2-3 (30-50% load) 4-8 (50-90% load) 3-5 (90-100% load)	

Table 1 Typical operating flexibilities of power plants without CCS

The flexibility of NGCC plants has improved in recent years as suppliers continue to respond to customers' requirements for greater flexibility and modern NGCCs are typically capable of fast start-up, shut–down and load cycling. The minimum operating load is usually determined by the increasing environmental emissions at low loads.

USC-PC plants are also characterised by low minimum operating loads and good cycling capabilities and start-up times. In contrast, IGCC plants have relatively low cycling capabilities, high minimum load and long start-up times although faster start-up may be possible if an auxiliary fuel is used in the gas turbines.

Operating flexibility of power plants with CCS

There is currently relatively little information in the public domain on operating flexibility of CO_2 capture processes and more practical research and dynamic modelling is needed. This report provides illustrative information on CCS plant flexibilities but it should be recognised that flexibilities depend to some extent on the needs of the operators and there is a trade-off between flexibility, costs and efficiency, which is explored to some extent in this report. The characteristics of electricity systems in future may be significantly different to those at present, so it is important that there is a dialogue between CCS process developers and electricity system planners, modellers and operators to ensure that CCS processes are designed to have the appropriate degree of flexibility.

One of the general constraints on part load operation of CCS plants would be the CO_2 compressors which would typically be limited to around 70% turndown. Higher turndown could be achieved by recycling compressed CO_2 but this would impose a significant energy penalty, as the compressor would still be operating at 70% load even when the power plant was turned down further. It would therefore be advantageous to have multiple CO_2 compressors, which may be required anyway due to size limitations, particularly in multiple train power plants. This report is based on power plants that include one or two power generation units. Larger plants with multiple units and common air separation and CO_2 compression may provide improved part load performance.

NGCC and USC-PC with post combustion capture

The introduction of post combustion CO_2 capture may impose additional constraints on the start-up and fast load changing of a power plant but techniques are available to overcome these constraints. In an NGCC plant the gas turbine starts up more rapidly than the heat recovery steam generator (HRSG) and the steam turbine. The regenerator in the CO_2 capture plant requires steam from the HRSG or steam turbine and the regenerator needs to be heated to its operating temperature. To avoid constraints on start-up time and to avoid CO_2 emissions during start up, the CO_2 absorber could be operated using lean solvent from a storage tank and the CO_2 rich solvent from the absorber would be stored and fed to the regenerator later. This would enable an NGCC or USC-PC plant with CO_2 capture to start up and change load as quickly as a plant without capture. This technique is evaluated in the report.

Oxy-combustion

The main constraint on flexibility of a pulverised coal oxy-combustion plant is the air separation unit. The minimum operating load of the cold box is around 50% while the minimum efficient load of the main air compressor is around 70%. At lower loads, part of the compressed air would generally be recycled to the compressor feed, which imposes a substantial efficiency penalty. This could be avoided in a multi-train plant in which one or more of the compressors could be shut down.

The maximum ramp rate of the ASU is typically 3% per minute but the boiler can typically ramp at 4-5%. The difference between the ASU oxygen supply rate and the boiler demand for a 50%-100% ramp is less than 10 tonnes for a 500MWe plant and this can be satisfied by using stored liquid oxygen (LOX). The LOX storage tank can be refilled during times of reduced power plant load. Around 200 tonnes of LOX storage would typically be included in the plant for the safe change-over from oxygen to air firing and in case of a ASU trip, so no additional LOX storage would be needed to satisfy the ramp rate.

IGCC

As mentioned earlier, the flexibility of IGCC plants without capture is relatively poor but the addition of capture is not expected to significantly affect the flexibility because for example the changes to the design of the acid gas removal plant have no impact on the plant flexibility. Plants with capture will however have reduced part load efficiency for example due to the lower efficiency of CO_2 compression at part load which is discussed earlier.

Part load efficiencies

The efficiencies of power plants with CO_2 capture at part load are shown in Figure 1.

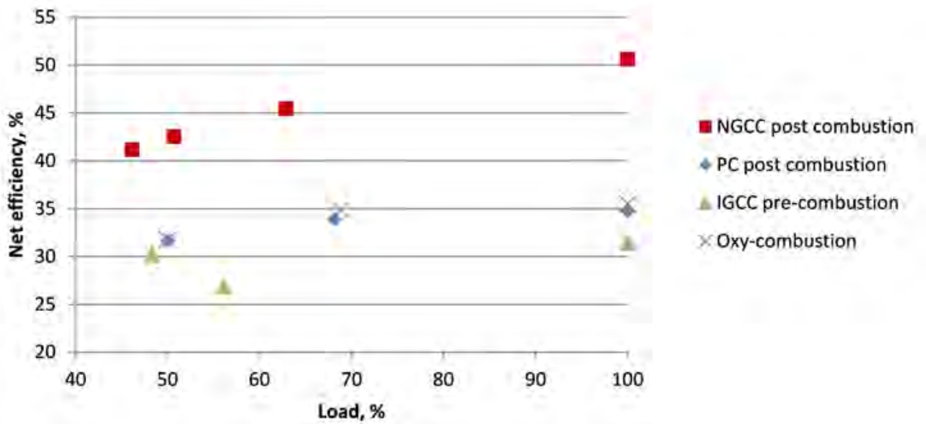


Figure 1 Part load efficiencies of plants with CO2 capture

The efficiency reduction for operation at 50% load is 3.1 percentage points for the PC plant with post combustion capture. This is higher than for a plant without capture, mainly due to the need to maintain the pressure of the steam extracted from the turbine for the CO_2 capture plant, the lower efficiency of CO_2 compression and miscellaneous changes within the capture unit. The efficiency reduction for PC oxy-combustion is similar at 3.8 percentage points. The main reasons for the higher efficiency reduction in this case are the lower efficiencies of the ASU and CO_2 compressors.

The part load efficiency reduction for NGCC and IGCC depends mainly on the performance of the gas turbine and the data in this report are based on a model of gas turbine that has a relatively high part load efficiency loss. In recognition of the increasing importance of plant flexibility some gas turbine vendors are introducing turbines that have improved part load performance, as illustrated in the main report.

The data points in Figure 1 for NGCC at 50% load and IGCC at 56% load are for operation with both of the gas turbines turned down. The data point for IGCC at 48% load is for operation with one of the gas turbines shut down and the other operating at 100% load, which is significantly more efficient. This operating mode could also be used for NGCCs but it was not analysed in this study.

Assessment of techniques for improving flexibility

Turn off or turn down of CO_2 capture

The net power output of a plant could be increased by turning down or turning off the CO_2 capture and compression units and emitting more CO_2 to the atmosphere. The ability of a plant with capture to ramp up power output could in principle be better than that of a plant without capture if the load of the capture unit was reduced at the same time as the load of the power generation unit was increased. This study assessed the option of turning off capture but various intermediate options involving turning off or turning down parts of the capture plant may also be attractive.

Turning down or turning off capture would increase emissions of CO_2 to the atmosphere so regulations would have to permit CCS plants to emit more CO_2 during times of peak power demand. This would for example require emission performance standards to be assessed over long periods such as a year. To comply with performance regulations it may be necessary to capture a higher percentage of CO_2 during normal operations to compensate for the extra emissions when the capture plant is turned off. The feasibility and costs of doing this have not been assessed in this study.

Turning down or turning off post combustion capture would reduce the plant's internal consumption of electricity and the low pressure steam that would otherwise be consumed by the capture unit could be used to further increase the net power output, provided the plant was built with the necessary extra low pressure turbine capacity.

Turning off capture in IGCC plants is less straight forward than in plants with post combustion capture because the CO_2 capture unit is an integral part of the acid gas removal (AGR) unit which also removes sulphur compounds from the fuel gas. However, it is possible to tune to a certain extent the CO_2 capture rate by varying the solvent circulation rate flowrate in the AGR unit, in order to absorb sufficient H_2S while only absorbing part of the CO_2. With this strategy the capture rate range at which it is possible to operate is limited by both the AGR design and the flexibility of the gas turbine to accept a variable fuel composition. In the plants considered in this study the captured CO_2 that is available at high pressures from the AGR is fed to the gas turbines. This enables the quantity of nitrogen that has to be compressed for use in the gas turbines to be reduced, which reduces the compressor power consumption and hence increases the net power output of the plant. CO_2 that is available from the AGR at low pressure is vented to the atmosphere but changes to the plant need to be made to reduce emissions of trace components in the vent stream, particularly H_2S and CO, to environmentally acceptable concentrations. In this study two techniques were assessed:

1. Modification of the AGR to improve the purity of the CO_2 vent stream.
2. Include a partial oxidation unit and an activated carbon bed to clean-up the CO_2 vent stream.

The modified AGR case has the higher peak power output and efficiency during peak load operation and a lower capital cost but it has a lower efficiency during the time when CO_2 is captured.

Only qualitative assessment of turning off capture in oxy-combustion plants was considered. The option of continuing to capture CO_2 while turning down the ASU and using stored oxygen in the boiler, which is discussed later, was expected to be more attractive than short term switching between oxygen and 'air-firing' modes.

The results of the analysis of turning off capture are summarised in Table 2. The specific emissions for peak power generation shown in this table are calculated in the following way:

$$Ep = \frac{Ev - Er}{Pv - Pr}$$

Where:
Ep is Emissions for peak generation, t/MWh
Er is Emissions from the reference plant operating with capture, t/h
Ev is Emissions from a plant venting CO_2-containing gases, t/h
Pr is Net power output of the reference plant with capture, MW
Pv is Net power output when venting CO_2-containing gases, MW

Specific costs for peak generation are calculated in a similar way.

	NGCC	PC	IGCC
Increase in power output with no capture, %	15.9	27.4	6.4
Thermal efficiency, %			
Reference plant with capture	50.6	34.8	31.4
Plant with capability to turn off capture	50.2	34.2	31.1
Plant with capture turned off	58.6	44.3	33.5
Capital cost			
Change in cost per kW of normal output, %	+5.8	+3.9	+0.5
Change in cost per kW of peak output, %	-8.7	-18.5	-5.6
Cost of extra peak power capacity, €/kW	354	322	213
CO_2 emissions			
Tonnes CO_2 per MWh of extra peak power	2636	2944	10450

It can be seen that having the capability to turn off capture increases the capital cost of the plant (per kW of normal power output), mainly because of the need for greater steam turbine capacity, but the cost per kW of peak power output is lower. The net capital cost per kW of extra peak power generation capacity is relatively low, probably less than the cost of other types of peak generation capacity such as simple cycle gas turbines but the specific emissions of CO_2 per kWh of extra peak power generation are high, particularly for IGCC. Including the ability to turn off post combustion capture reduces the net efficiency of the plant during normal operations because the low pressure steam turbine is oversized to enable it to use the extra low pressure steam that is available when capture is turned off. The turbine therefore operates at non-optimum conditions when the capture plant is operating. To avoid this efficiency reduction a separate steam turbine could be installed to use the low pressure steam that is available when capture is turned off. This approach was adopted in the solvent storage cases described later.

The economic viability of turning off capture would depend on the carbon emissions cost, the number of hours per week that capture is turned off and CO_2-rich flue gas is vented and the peak electricity prices during the time when capture is turned off. The relationship between these parameters for a base load PC plant is shown in Figure 2. Peak power costs would be slightly lower for turning off capture in an NGCC than a PC plant.

The peak power price will be determined by the cost of alternative peak load generation techniques, including simple cycle gas turbines and energy storage (pumped hydro, compressed air energy storage, batteries etc). Determining the costs of these techniques was beyond the scope of this study but in Figure 2 of this overview the costs of a simple cycle gas turbine (SCGT) plant are included for comparison with the costs of turning off CO_2 capture. The SCGT plant was assumed to have an efficiency of 40% (LHV), a capital cost of €450/kW, and an emission cost of €50/t of CO_2. Two SCGT cases are shown, one based on natural gas at €8/GJ and the other based on distillate oil at the current price of €16/GJ.

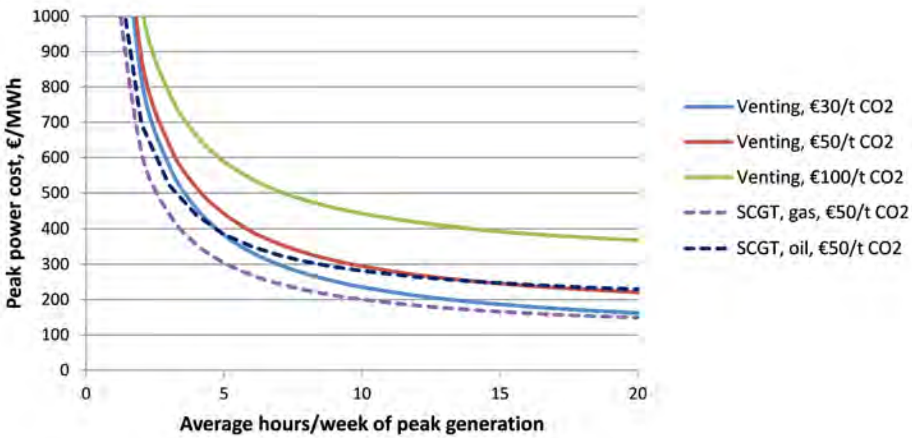


Figure 2 Economics of turning off CO2 capture (PC plant)

The overall cost of generation increases as the number of hours per week that CO_2 capture is turned off is reduced because the fixed costs associated with turning off capture (Capex and O+M) are attributed to a lower number of MWh of peak power. It can be seen that for an emission cost of €50/t of CO_2, turning off capture is less economically attractive than an SCGT, although the costs are broadly similar if oil has to be used as the fuel for the SCGT. The economic advantage of the SCGT becomes greater at higher CO_2 emission costs, because the specific emissions associated with capture by-pass are higher than for an SCGT.

Solvent storage

Solvent from post combustion capture can be stored during times of peak power demand for regeneration during times of lower power demand. This reduces the requirement for other peak generation capacity. The extra generation during peak times would have low CO_2 emissions, unlike the alternatives of by-passing CO_2 capture as described earlier, or using peaking plants such as simple cycle gas turbines without CCS. Solvent storage in IGCC was not assessed in this study because the Selexol solvent would have to be stored at high pressure and it was expected that the costs would be high compared to other techniques e.g. liquid oxygen storage.

Foster Wheeler discussed the practicality of CO_2 solvent storage with some leading technology suppliers, including MHI, Aker Clean Carbon and Alstom. These companies all confirmed the technical feasibility of storing solvent, provided the temperature of CO_2-rich solvent is maintained at or slightly below the absorber bottom outlet temperature to avoid degassing. High rates of degradation are not expected, degradation would be mainly due to the reaction with oxygen, so nitrogen or CO_2 blanketing would always be considered. MEA-water solution that would be stored in capture plants is not flammable but solvent is toxic and the stores are potentially large, as discussed later, so it may not be acceptable at all locations.

Regeneration of stored solvent could take place during times of 'base load' operation or during times of low power demand when the power plant is operating at part load. The operating mode of the plant would determine the required capacities of the solvent storage tanks and the solvent regeneration and CO_2 compression equipment. If the plant is required to operate only at 'base load' the solvent regenerator and CO_2 compressor would need to be oversized to cope with regeneration of the solvent from 'peak load' operating hours. If the plant is expected to operate for some of the time at reduced load, the stored solvent could be regenerated during these times and the regenerator and compressor would not need to be oversized. If a plant is expected to regularly operate at substantially reduced load at night and at weekends, the solvent regenerator and CO_2 compressor could be undersized, i.e. they could be made smaller than in a normal base load power plant, thereby reducing capital costs. However, such a plant would not have the ability to operate at base load for long periods of time and this may not be attractive to the plant owner.

Two operating scenarios described below were assessed in this study as an illustration but it is recognised that in reality power plant operations will depend on many external factors which may change during the operating life of a plant. PC plants were assumed to be operated at higher load factors than NGCC plants at night and at the weekend because their lower marginal operating costs would put them higher up the operating 'merit order'. The 'weekly' and 'daily' scenarios involve different amounts of solvent storage and peak load operation.

1. Daily storage scenarios
   a) PC plant: Operation at peak load for two hours during the weekday day-time, normal full load for the remaining 14 hours of the day-time and 50% load for 8 hours of night-time and all weekend. Stored solvent is regenerated during the night-time.
   b) NGCC plant: Operation at peak load for two hours during the day-time, normal full load for the remaining 14 hours of the daytime and shut-down during night-time and weekend. Stored solvent is regenerated during normal day-time operation.

2. Weekly storage scenarios
   a) PC plant: Operation at peak load for 16 hours during weekdays and operation at 50% load during 8 hours of night-time and all weekend. Stored solvent is regenerated during the night-times and weekend.
   b) NGCC plant: Operation at peak load for 16 hours during weekdays and shut-down or operation at the minimum load required for solvent regeneration during night-time and weekend.

In the weekly scenarios the 'peak' times are almost half of the total hours. For the PC plants, if solvent regeneration was completely switched off during peak times in these scenarios the amount of CO_2-laden solvent to be stored would be extremely large. Also the regenerator would have to be substantially larger than in the reference plant and it may be difficult to provide sufficient steam for the regenerators during the off-peak times when the plant is operating at 50% part load. In the weekly scenarios assessed in this study the solvent regeneration was therefore reduced by only 25% at peak times. Two alternatives were assessed:

1. Reduced regenerator size. The regenerator is about 85% of the size in the reference plant, which enables all of the stored solvent to be regenerated during off-peak times.
2. 100% regenerator size. There is no reduction in the size of the regenerator, which would enable the plant to operate for long periods at 100% load if required. To minimise the capacity of the storage tanks the regenerator is operated at full capacity during the weekday night time, and it is operated at lower throughput during the weekends.

The lower capital cost of storage tanks and stored solvent in alternative 2 is greater than the extra cost of a larger regenerator. This lower capital cost and the greater flexibility to operate at full load means that alternative 2 is preferred, so results for this are presented in this overview.

In the NGCC weekly scenario, if solvent regeneration was completely switched off during peak times the amount of CO_2-laden solvent to be stored would be extremely large, although less so than in the PC plants because gas fired power plants have lower specific CO_2 production. It is possible to store 50% of the solvent during peak times without having to oversize the regenerator. Solvent is regenerated at off-peak time by operating one of the two gas turbines at minimum environmental load. As with the PC plant, the lowest cost and most flexible option is to have a 100% sized regenerator.

In the daily operating scenario, solvent regeneration is shut down completely during the 2 hours of peak operation and all of the CO_2–rich solvent produced during this time is stored. In the PC plants the stored solvent is regenerated during the night time when the plant is operating at 50% load. In the NGCC plants the stored solvent is regenerated during the remaining 14 hours of daytime operation, which requires the regenerator to be over-sized by about 14% compared to a capture plant without solvent storage. The NGCC plants shut down overnight and at weekend.

Solvent storage has very little effect of the thermal efficiency except for the NGCC weekly scenario, in which one of the gas turbines has to operate at minimum environmental load at off-peak times to regenerate solvent. The solvent storage tanks are conventional sized tanks as used at oil refineries but they are nevertheless large, particularly in the weekly scenario. As an example, in the NGCC daily scenario four tanks each of which is 27.4m diameter and 12.8m high are required.

Power plant type	NGCC	PC	NGCC	PC
Storage scenario	Weekly	Weekly	Daily peak	Daily peak
Hours per week of peak output	80	80	10	10
Increase in power output at peak times, %	6.2	4.8	12.1	22.2
Thermal efficiency, %				
Reference plant efficiency, 100% load	50.6	34.8	50.6	34.8
Reference plant time weighted average efficiency	50.6	33.6	50.6	33.6
Storage plant time weighted average efficiency	45.3	33.5	50.5	33.6
Capital cost				
Change in cost per kW of normal output, %	+19.6	+6.1	+9.3	+5.8
Change in cost per kW of peak output, %	+12.6	+1.2	-2.6	-13.5
Cost of extra peak generation, €/kW	3116	2891	752	589
Solvent storage				
Quantity of solvent storage, $103m^3$	286	199	30	46

Table 3 Storage of post combustion CO_2 capture solvent

The overall economics of solvent storage are complex because there are substantial changes in the electricity output at various different times. An electricity price profile at different times is needed, which is beyond the scope of this study. However, an initial assessment of the economics can be made by comparing the capital cost of solvent storage and alternative means of generating peak load electricity. In the weekly scenario the capital cost per kW of additional peak generation capacity is greater than the cost of the reference power plant, which indicates that this scenario is unlikely to be attractive. In the daily scenario the capital cost per kW of additional peak generation capacity is less than the cost of the reference plant but it is probably higher than the cost of the leading alternative technology for peak load generation, namely simple cycle gas turbines. Solvent storage may be attractive in this scenario, depending on fuel prices, carbon emission costs and the electricity price profile.

Liquid oxygen and air storage

Storage of liquid oxygen (LOX) in oxy-combustion and IGCC plants can provide a boost to the peak power output by reducing the power consumption for oxygen production. During the times of peak power demand the power plant is operated at full load, the air separation unit (ASU) is operated at minimum load and the rest of the oxygen required by the power plant is taken from a LOX store. In the oxy-combustion plant the LOX is vaporised by condensing liquid air which is then stored and in the IGCC plant the stored LOX is vaporised using LP steam. During off-peak times the power plant is operated at part load but the ASU is operated at a higher load to enable the LOX store to be re-filled. Performance and cost data for PC oxy-combustion and IGCC plants with oxygen storage are shown in table 4.

An alternative that was evaluated in the report but which is not shown in this overview involves having a smaller capacity ASU which is operated at constant load. This option would reduce the capital cost and oxygen storage requirement but it would give a smaller boost to the power output at peak times. The plant would also not have the flexibility to operate at full load for long periods of time, similar to the post combustion cases with a reduced size solvent regenerator mentioned earlier.

The minimum efficient turndown of an ASU air compressor is 70% and the minimum turndown of the cold box is around 50%. In IGCC, turndown of the main ASU air compressor to 70% would give only a marginal increase in net peak power output. The ASUs are therefore configured to have two smaller air compressors, one of which is turned off during the time of peak demand and the other is operated at 70% load. Having multiple compressors increases the capital cost but provides greater opportunity for high peak generation. Half of the compressed air for the ASU in the IGCC plants is provided by extraction from the gas turbine, which earlier studies and practical experience has shown results in relatively high efficiency, good operability and low costs. When the power plant is operating at part load, less air is available to the

ASU from the gas turbine compressor. To operate the ASU at full load more air has to be provided by the ASU's own air compressors, so an additional compressor is provided for each ASU.

In the oxy-combustion case shown in table 4 there are two 50% capacity ASUs, each equipped with two 60% capacity main air compressors. During peak times one of the main air compressors per train is turned off but the ASUs are kept in operation because it is not feasible to shut down the ASU cold box due to its long start-up time. In the oxy-combustion plant only liquid oxygen and liquid air need to be stored but in the IGCC plant liquid nitrogen also has to be stored, as nitrogen is required for the gas turbine. Nitrogen accounts for more than half of the total storage volume.

Power plant type	PC-oxy	IGCC	PC-oxy	IGCC
Storage scenario	Weekly	Weekly	Daily	Daily
Hours per week of peak output	80	80	10	10
Power output				
Increase in output at peak times, %	5.3	7.7	5.8	10.5
Thermal efficiency, %				
Reference plant efficiency, 100% load	35.5	31.4	35.5	31.4
Reference plant time weighted average efficiency	34.0	29.5	34.0	29.5
Storage plan time weighted average efficiency	34.8	30.0	34.3	28.9
Capital cost, €/kW				
Change in cost per kW of normal out put, %	+2.5	+2.7	+0.9	+1.4
Change in cost per kW of peak output, %	-1.5	-4.6	-4.6	-8.2
Cost of extra peak generation, €/kW	1573	928	381	336
Storage of liquid oxygen and nitrogen/air				
Quantity stored, $103m^3$	12.1	24.0	0.8	3.4

Table 4 Storage of Oxygen

The volumes of storage are much smaller than in the solvent storage cases but vessels have to operate at cryogenic temperatures.

The capital costs of peak generation are relatively low because unlike the earlier cases no additional power generation equipment has to be installed, instead the increased peak power is achieved by reducing the plant's ancillary power consumption. Although the capital costs per kW of normal power output increase, the costs per kW of maximum peak output decrease, particularly for the daily storage scenarios. The capital cost of the extra peak generation capacity in the daily storage scenarios is competitive with simple cycle gas turbines and the storage option has the advantage that extra peak generation has low CO_2 emissions. This preliminary analysis indicates that oxygen storage should be an attractive option for providing additional peak generation.

Hydrogen-rich gas storage

The flexibility of IGCC plants could be improved by storing surplus hydrogen-rich fuel gas produced during off-peak times. The stored hydrogen could be used to generate electricity at peak times or it could be supplied to other energy consumers. This would have the practical and economic advantages of enabling the gasification plant to continue to operate at full load at all times. The leading option for hydrogen storage would be underground salt caverns, which are a proven and relatively low cost technique for large scale hydrogen storage. Some liquid nitrogen would also be stored to satisfy the needs of the gas turbine. Performance and cost data are given in Table 5. The increase in peak power output per unit of gas turbine capacity is relatively small (3.3%) but the increase per unit of gasification plant capacity is greater (26.0%). The overall capital cost per kW of peak capacity is 8.5% lower than the reference IGCC plant. The capital cost of the extra peak generation capacity is negative because the capital cost of the plant is lower and the peak output is higher, although it should be noted that the plant would be unable to operate at continuous full load because of the under-sized gasification plant.

Power plant type	IGCC
Storage scenario	Weekly
Hours per week of peak output	80
Increase in power output at peak times, %	
Per unit of gasifier capacity	26.0
Per unit of gas turbine capacity	3.3
Thermal efficiency, %	
Reference plant efficiency, 100% load	31.4
Reference plant time weighted average efficiency	29.5
Storage plant time weighted average efficiency	29.7
Capital cost, €/kW	
Change in cost per kW of normal output, %	-5.5
Change in cost per kW of peak output, %	-8.5
Cost of extra peak generation, €/kW	negative
Storage of hydrogen and nitrogen	
Quantity of hydrogen stored, 103m3 working volume	100
Quantity of liquid nitrogen stored, 103m3	7.2

Table 5 Storage of hydrogen

The hydrogen storage volume is relatively small for a typical modern salt cavern store, for example about 5% of the capacity of a hydrogen storage cavern being built in Texas. This study focussed on coping with sort term (up to a week) variability in electricity demand. The relatively low cost of underground hydrogen storage means that this technique could also be cost effective for smoothing out longer term seasonal variability in electricity demand.

Another case was assessed in which the gasification and CCS is operated at continuous full load, a constant flow of high purity hydrogen for other consumers is maintained at all times and some of the hydrogen rich gas from the CCS plant is stored at off-peak times. Details of this case are provided in the main report.

Constant flow of CO_2 to transport and storage

Variation of the throughput of a CO_2 capture plant would result in variation of the flow-rate of CO_2 to the transport pipeline and storage site. Little information is currently available on the ability of dense flow pipelines and storage wells to accept variable and intermittent CO_2 flows and the effects may be site specific. Two techniques for providing a constant flow of CO_2 were assessed,in case this should turn out to be required:

1. Buffer storage of compressed CO_2.
2. Buffer storage of CO_2-rich solvent, combined with a reduced solvent regenerator capacity.

In Case 1 it was assumed that CO_2 would be stored in cylindrical pressure vessels. If longer term storage was required and suitable geology was available near the power plant site it may be worthwhile considering an underground temporary buffer store.

Providing CO_2 buffer storage for the NGCC and PC plants with the 'weekly' operating scenario described earlier (in the section on solvent storage) would increase the plant capital cost by €30-40/kW. This cost could in principle be offset by a reduction in the size and cost of the CO_2 pipeline (and injection wells), for example in the NGCC case the cost savings for a 100km dedicated CO_2 pipeline would more than offset the cost of CO_2 storage. However if a small pipeline was built the plant would not be able to operate at continuous full load for long periods of time. The modest extra cost of installing a full capacity pipeline may be considered worthwhile to maintain the option to operate the plant at high load factors if required.

Case 2 (reduced capacity solvent regenerator and buffer storage of CO_2 capture solvent) was found to be substantially more expensive than Case 1 (storage of compressed CO_2).

Expert Review Comments

Comments on the draft report were received from seven reviewers who have expertise in the power industry, oxygen production, IGCC project development, and research on post combustion capture and CCS plant flexibility. IEAGHG and the contractor reviewed the comments and various detailed changes were made to the report. The contribution of the reviewers is gratefully acknowledged.

In general the reviewers thought the report was of a high standard. Some reviewers emphasised that many operational issues still need to be considered in detail and more dynamic modelling and optimisation of the control of power plants and capture units is needed. This was emphasised more in the report.

Some reviewers expressed concerns that the load profiles originally assumed for the flexibility assessments may not be optimum as they resulted in excessive amounts of solvent storage, which raises economic, safety and regulatory concerns. To address these comments, additional cases involving short term peaking operation and substantially lower quantities of solvent storage were evaluated. More part load operation cases were also assessed and the oxy-combustion case with oxygen storage was modified to also include liquid air storage, to address reviewers' comments.

Conclusions

- CCS may impose additional constraints on the flexible operation of power plants but in general there are ways of overcoming these limitations. A plant with CO_2 capture may even be able to ramp up its net power output more quickly and produce more peak generation than a plant without capture, using the techniques considered in this study.
- The efficiency penalties for part load operation are expected to be somewhat greater for plants with CO_2 capture than plants without capture, for example around 3 percentage points at 50% load for a pulverised coal plant with post combustion capture compared to around 2 percentage points for a plant without capture.
- Increasing the power output by turning down or turning off the CO_2 capture unit may be an attractive technique for short periods, depending on the peak power price and CO_2 emission cost but preliminary analysis indicates that simple cycle gas turbines may be a lower cost option for peak load generation. Regulations would need to allow the resulting increase in CO_2 emissions, for example by averaging emission performance standards over a long period. Some additional equipment, particularly steam turbine capacity, would have to be installed to obtain

the full benefit from turning down or turning off the capture unit, which would increase the capital cost. Turning off capture could increase the net power output by 27% for a pulverised coal fired plant and 16% for a natural gas combined cycle plant.

- Storing CO_2–rich solvent and regenerating it at a later time may be attractive as a way of increasing power plant ramp rates and for increasing the net power output during short term peaks in power demand. However, the large quantity of solvent that would have to be stored would mean that operating at peak output for longer periods of time would not be attractive. Plants could be built with a wide range of storage volumes, solvent regenerator sizes and peak power generation capacities; selecting the optimum would be a difficult commercial decision. Storing solvent could increase the net power output by 22% for a pulverised coal fired plant and 12% for a natural gas combined cycle plant.
- Liquid oxygen and air/nitrogen could be stored in oxy-combustion and IGCC plants to improve flexibility and increase net peak generation by 5-10%. From an economic perspective this is expected to be a relatively attractive option for short term peak power generation.
- Hydrogen produced in IGCC plants with pre-combustion capture could be stored for example in underground salt caverns, which are commercially proven. This would enable the gasification and CCS equipment to operate at continuous full load and only the combined cycle plant would need to operate flexibly to cope with variable power demand. This would be a significant practical and economic advantage for non-base load power generation. Underground hydrogen storage would be suitable for longer-term as well as short term storage, which could be an advantage particularly in electricity systems that include large amounts of variable renewable generation.
- Compressed CO_2 could be stored at capture plants to reduce the variability of flows of CO_2 to transport and storage, if this is found to be necessary. Buffer storage of CO_2 would enable a smaller capacity CO_2 pipeline to be built but this would constrain the ability of the power plant to operate at continuous full load, which may not be commercially attractive.

Recommendations

- IEAGHG should assess the ability of CO_2 transport and storage systems to accept variable and intermittent flows of CO_2.
- IEAGHG should undertake further work to determine the requirements for CCS plant flexibility, including collaboration where appropriate with other organisations that are undertaking modelling of electricity systems that include other low CO_2 technologies.
- IEAGHG should validate the methodology and results of this study when further information becomes available from plant dynamic modelling and pilot and demonstration plant operation.
- IEAGHG should propose further reviews and studies on CCS flexibility when appropriate.

2012-07 GASEOUS EMISSIONS FROM AMINE BASED POST-COMBUSTION CO_2 CAPTURE PROCESSES AND METHODS FOR THEIR DEEP REMOVAL

Introduction

Amine based post combustion CO_2 capture technology is widely seen as a promising option for reducing atmospheric emissions of CO_2. Great efforts have been made to develop and demonstrate this technology. However less attention has been given to the likely emissions of amines and their degradation products, some of which are well known to be harmful to human health and the environment. The components of concern do not currently figure in the emission slate of power plants. Standards and legislation are thus not fully developed for their control, particularly considering the scale on which CCS plants may be deployed. A full understanding of the nature of the likely emissions and the limits which need to be imposed is necessary so that appropriate improvements in the capture process can be made to protect human health and the environment from adverse impacts. This study was executed to identify the chemical species likely to be emitted, estimate the levels of emission expected from the present generation of capture plant designs, assess what emission limits might be applied and research the process modifications needed to meet these limits.

Approach

The study was awarded to CSIRO, Australia on the basis of competitive tender. The first step was to make estimates of the most likely chemical emissions. In this report this was done on the basis of emissions from amine based inhibitor-free solvents, particularly those based on MEA, ammonia and amino acid salts, and their degradation products. MEA was chosen for more detailed assessment as this is currently the major constituent of most absorption solvents used in post combustion capture systems. Chemical emissions and wastes from the CO_2 capture process fall into three categories.

1. Physical entrainment and evaporative loss of amine and its degradation products into the gas streams.
2. Discharge of organic degradation products, heavy metals and heat stable salts in the liquid waste streams.
3. Fugitive emissions during plant operation and handling of chemicals

This report only focuses on the first of the above mentioned emissions.

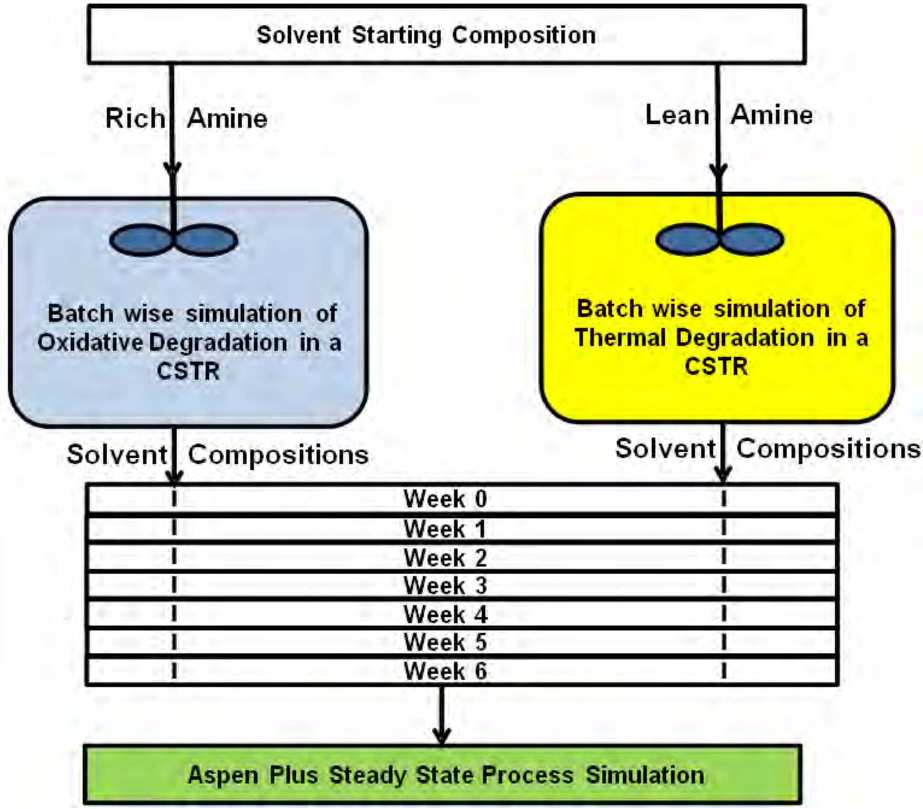
Estimates of gaseous emissions were made in two ways. First values mentioned in extensive literature on the amine based capture processes were examined enabling some idea of the likely range of emissions to be assessed. Second a simulation of the complex degradation reactions and the processes which occur in CO_2 capture plant has been made in order to provide an alternative assessment. Sampling and analysis of traces of chemicals in flue gas is difficult and most laboratory, pilot and demonstration work on the CO_2 capture process have tended to concentrate on the technical rather than environmental performance of the process. As a result there is both wide variation and uncertainty in the estimates for gaseous emissions.

Baseline PCC processes

Two processes based on the use of MEA solvent without addition of other additives were chosen as base cases for evaluation of chemical emissions via simulation. These processes were coal fired ultra-supercritical steam plant and gas fired combined cycle plant as defined in studies carried out previously for IEAGHG. These processes use a single stage water wash after the CO_2 absorber and for simulations cooling was applied so that flue gas exit temperature was reduced to 45°C. This choice is important because the levels of volatile compounds are greatly affected by temperatures in and after the absorber. Degradation of MEA proceeds via two main pathways, thermal degradation and oxidative degradation both of which have been considered in this study.

Modelling of Amine degradation and related emissions

Modelling of the amine degradation process was done using ASPEN plus and was divided into two elements. First was to build a steady state simulation of the capture process and second was to model the progress of the known chemical degradation reactions with time. It is not possible to use the steady state simulator for the time dependent reactions. Instead these were simulated in two separate stirred tank reactors one for the thermal and another for the oxidative degradation reactions.



Depiction of MEA Degradation Calculation Routine

As the MEA solvent in an absorption plant degrades some degradation products will build up, for example heat stable salts, and these are removed from a slip stream of solvent either continuously or batch wise in a reclaimer. The reclaimer recovers amine and concentrates the degradation products for disposal as waste. If the batch-wise operation is chosen the composition of the solvent gradually changes until the reclaimer is re-started. This is generally every few weeks. The simulation was based on batch-wise reclamation as follows. The stirred tank reactors were allowed to run for up to 6 weeks and compositions of solvent were derived at the end of each week. These compositions were then used in the steady state simulator to calculate gaseous emissions from the absorber at that point in time.

Simulation runs were made in which it was assumed that no droplet carryover was occurring and also with carry over set at the worst prediction for demister performance found in the GPSA handbook namely 0.13M^3/million m3. This is a very high value but it enables a worst case scenario and the split between vapour and liquid carryover effects for each component to be estimated.

The reactions modelled were based on the open literature. However not all reactions could be modelled and not all components were available in the ASPEN database. Where this was a limitation the reactions either had to be omitted or in the case of a missing component data a component with similar volatility was chosen for the steady state simulator. There were also some reactions, one notably involving DEA, where there are differences of opinion as to what reactions are occurring.

Literature data on emissions

This report contains extensive data and references both on measured and estimated emissions but also on the reactions involved in amine degradation. The chemical pathways, equilibrium and kinetic data chosen for modelling the degradation reactions are presented. In addition the estimated and measured emissions from a number of laboratory investigations and demonstration plants are reported.

Estimated emission levels from simulation

The results from simulation are different but not in conflict with those which have been measured in practice. Even though very pessimistic assumptions have been made about droplet carry over there are some measurements which are higher than simulator predictions. On the other hand the effect of droplet carry over is often not dominating particularly for the more volatile components. This report summarises the expected ranges for both the USC coal and NGCC cases in a table of maximum and minimum expected values for all compounds expected to be detectable. The maximum values calculated in the simulations are shown below.

There were considerably higher values for emissions found for the gas fired case but this was largely because the process conditions and line up of the water wash were based on a relatively early study done for IEAGHG. This illustrates the importance of designing for the optimum temperature conditions in the absorber and water wash sections of post combustion capture processes in order to minimise emissions from the solvent and its degradation products.

Component	mg/Nm³ dry CO_2 lean Flue gas
MEA	5.5
NH_3	1.14
DEA	0.254
FORMALDEHYDE	0.314
ACETALDEHYDE	0.326
ACETONE	0.422
METHYLAMINE	0.26
ACETAMIDE	0.0002

Maximum emission levels from simulations of coal and gas fired MEA based CO_2 post combustion capture plant

Three principle heavier degradation products Oxazolidone, 1-(2 Hydroxyethyl) imidazolidone-2 (often abbreviated to HEIA) and N-(2-Hydroxyethyl)-ethylenediamine (often abbreviated to HEEDA) which have slight volatility were found to have extremely low emission levels in the simulation. The single stage water wash is very effective in removing heavier components

Emission levels from literature

This report includes data from a number of references which show that emission levels which have been measured have been both substantially higher and lower than the simulated values. In some cases the exact process conditions are not available The best general conclusion that can be drawn is that there is potential for chemical emissions although with a one stage water wash at close to ambient temperature these emissions can be lowered but not reduced to the point that they can be considered as negligible.

Of particular interest are references in the literature on the formation of nitrosamines. The formation of these components was not included in the simulation as the exact mechanisms are not known yet. Nitrosamines have been detected in the solvent by some researchers but the exact mechanism of their formation is not agreed. Nitrosamines are known to be a class of compound which can be highly carcinogenic. Their formation is thought to be due to reactions of NOx with secondary/tertiary amines but MEA itself is not thought to be the precursor in stable nitrosamine formation. The nitrosamines detected are N-nitrosodiethanolamine (NDELA) and nitrosodimethylamine (NDMA). Diethylamine (DEA) was also detected in the solvent and may be a precursor for these nitrosamines although the origin of the DEA is uncertain. A small amount of the nitrosamine (NDELA) has been measured in the Trona plant in California at the level of nearly 3 µmol/ml but this level may however only have been reached after a long build up period. To estimate whether this would result in an emission the simulation was run with this high amount added to the solvent. However this component is not in the library of ASPEN so the lighter dimethyl nitrosamine was substituted to check whether any emission was possible.

The results of the simulation of this extreme case predicted between 2 and 6 mg/Nm^3 of this component in the exhaust flue gas mainly due to its high vapour pressure and not due to liquid carry-over. Thus with a single water wash there is a remote possibility for detectable levels of nitrosamines to be emitted especially if they are allowed to build up in the solvent over a very long period of time. Further work needs to be done to demonstrate conclusively that they will not be emitted.

Processes to reduce chemical emissions

The processes currently applied for reducing gases and fine droplets are cooling, demisting and water washing. The reason that a single stage water wash is not effective is that the water has to be circulated and the chemicals which are washed out build up. They then exert a vapour pressure and the water with contaminants can be entrained as droplets. The simulations show clearly the value of cooling the outlet stream as far as possible and one good way to do this is to apply intercoolers in the absorber column so that the top temperature is kept low.

Increasing the number of scrubbing stages is an option but references suggest that while this further reduces the emissions levels it is only partially effective. Washing with an acid solution on the other hand appears from literature sources to be rather effective and this is because most of the contaminants react with acid. A range of choices for the acid are available through strong inorganic acids, weak organic acids even to carbonic acid itself. The weaker acids might allow captured MEA to be regenerated.

Other more exotic measures were investigated including exposure to UV radiation, adsorption on solid beds and, cryogenic cooling. UV radiation appears to be an option for dealing with Nitrosamines as it causes their decomposition. Solid adsorption beds would need to be regenerated by vacuum rather than pressurised operation or temperature swing because parasitic energy losses would otherwise be unacceptable.

A major difficulty would be selecting an active adsorbent which will not be unduly affected by the water vapour in the effluent flue-gas. It would certainly not be practical to dry the entire flue gas stream. Limited cryogenic cooling could improve emissions marginally as lowering temperature is already known to improve the effectiveness of water scrubbing. However it is costly since the whole stream must be cooled although some energy could be recovered in a regenerative heat exchanger. Cooling could not go below the freezing point and, unless reheated, the flue gases would no longer be buoyant.

This report examines the performance of various types of demister available on the market. Demisting is particularly important for complete removal of MEA as this is the component which will have the highest concentration in the wash system liquids. Three mechanisms are employed in the devices used for demisting. Impingement devices in which droplets collide with surfaces on which they subsequently coalesce and drain away. Inertial devices where gas flows through tortuous pathways which liquid droplets cannot follow because of their inertia and devices based on Brownian motion where very fine droplets impinge on a surface due to their irregular Brownian motion. These devices are described in some detail in this report which shows several examples of how separation efficiency correlates with droplet size. The most appropriate demisting device is identified as being the Swirl Mist Eliminator (SME). This combines high efficiency, good liquid drainage properties (important during overloading or process upsets) and space requirements which allow for it to fit inside the diameter of absorber and wash columns. Although they have no moving parts, they are more complex and likely to be more expensive than wire mesh and corrugated vane type demisters.

Emission standards and legislation

This report contains a comprehensive overview of the various directives, regulating bodies and emission standards which apply. This reveals that in general emission levels for the new chemical substances which might be emitted from CO_2 post combustion capture have yet to be established. Environmental and health data from industrial uses might help in this process but is in itself not a sufficient basis for defining emissions levels. In the case of compounds which are known or suspected carcinogens regulation is most likely to be to adopt Best Available Techniques (BAT) rather than to set an emission standard. Often no numerical standard is set for carcinogens as it is not possible to define a lower safe limit.

The industry may come up against three main types of emissions limitation. The first is simply the acceptable concentration in the air to safeguard human health. The second is the imposition of upper limits for the total annual emission industry of a substance in a country or region. For example ammonia is regulated in this way in Europe. This report however shows that the potential emissions from post combustion capture amine based plants of all major sources of CO_2 were captured would only contribute around 5% of this allowance. The third is limitations due to cumulative and instantaneous effects on plants and their habitats. For example nitrogen and sulphur emissions may be limited to avoid eutrophication and acidification.

Given that the acid wash process appears to be rather effective and that high efficiency demisting devices are available a conclusion could be made that these or similar enhanced measures will become the de facto standard when large scale CO_2 capture plants are deployed. Also the addition of a UV process to ensure complete elimination of nitrosamines is kept in reserve in the unlikely event that the acid washing and high efficiency demisting processes are found to be insufficient.

New solvent systems and their emissions

The likely emissions from two alternative systems for CO_2 absorption were examined. Amino acid salt solutions have relatively fast rate of CO_2 absorption, higher CO_2 selectivity, high stability towards oxygen, very low vapour pressure, high biodegradability and favourable binding energy but lower CO_2 absorption capacity than MEA solution. Due to these favourable properties, the amino acid salts have been deployed for commercial scale acid gas removal processes in the past, such as the Alkazid process. Recently, with the increase in interest in CO_2 post combustion capture, Siemens has developed a new process for CO_2 capture from power stations. As reported in the literature, this process produces an insignificant amount of degradation products and has lower emissions to atmosphere.

Aqueous ammonia processes have also been claimed, in the literature, as an effective separation with potentially low emissions despite the fact that ammonia is toxic and corrosive. The main attractions are claimed to be ammonia's estimated 3 times more CO_2 uptake capacity, relatively higher stability, no interference from SOx and NOx on the ammonia capture efficiency and less corrosive nature as compared to MEA. It is also reported in the literature that the chemical regeneration energy required by ammonia is about three times less and this is reflected in reduction in capital and operating cost by about 15% and 20% as compared with MEA. Researchers are currently trying to reduce ammonia losses and emissions. It is important that the performance of ammonia process is thoroughly evaluated to ascertain the operating costs, energy consumption and emissions prior to any construction of commercial scale plant is considered.

Both amino acid salt and aqueous ammonia processes seem to have an insignificant extent of solvent degradation and the base case emissions of ammonia is reported to be below 1 and 10 ppmw, respectively. There is no report on the list of any other degradation products (than ammonia) formed in these processes. On application of acid wash the emissions from these processes could be brought down to near-zero. UV methods are probably not required for these processes as there is no report on nitrosamine emissions from them. However the acid treatment process, recirculation or disposal of acid and salt, have to be further studied in the laboratory prior to implementation at larger scale.

Expert reviewer's comments

Some reviewers were concerned that the choice of MEA as the basis for this study was restrictive and that the potential of other solvents was not covered and even masked. The selection of a very high worst case liquid carry over figure was considered by some to be inappropriate and leading to suggestions that emissions might be higher than is realistic. Both these comments are acknowledged as valid. On the first the simulation of alternative solvents was considered beyond the scope of the study resources. On the second point the high value for worst case carry over was retained but the text modified to make clear that this represents an unlikely worst case scenario.

Some reviewers felt that the way nitrosamine levels in processes and literature was reported over-accentuated the possible risk of such emissions and the reality that they are very unlikely to be present at detectable levels. The text was modified to reflect this concern although the basic figures are still reported.

Based on reviewer's comments the tone of the report was altered to reflect that the extent of knowledge in this area is incomplete and is still undergoing rapid development. A considerable number of specific comments were received and the authors were very grateful for this extensive contribution and have amended many details in the report as a result.

Conclusions

The main conclusions of the report can be summarised as follows:

- Detectable levels of lighter components will probably be emitted to atmosphere from amine based capture plants employing single water wash technology,
- Emissions to air of heavier degradation products will be at well below detectable levels,
- Application of an additional acid wash is an effective way of eliminating emissions of the lighter components,
- The preferred choice of demister seems to be the Swirl Mist Eliminator (SME),
- Emissions standards are not yet set for many of the substances which are likely to be emitted,
- Stringent emissions standards and regulatory requirements to adopt best available techniques can be expected particularly so if even the presence of trace amounts of known carcinogens are confirmed,

- More research into emissions and their measurement is required,
- Regulatory authorities have much work to do to create an appropriate emission standards which can be applied to MEA based CO_2 capture processes.
- Some alternative solvents have lower emissions but may still need to apply similar additional clean up steps

Recommendations

Further work on chemical emissions from solvents should be promoted and in particular pilot and demonstration projects should be encouraged to monitor actual measurements of these emissions during normal operation and make detailed measurements during test runs. They should also be encouraged to measure and report on the build-up of the full range of degradation products with time. Requests for this type of information should be included in surveys of demonstration projects under the Phase 2 of the "What We have Learned" data collection and analysis initiative.

Work is also needed to assess the fate of any emissions in the atmosphere and the programme could consider carrying out a study of available results once a substantial body of scientific information on this is available.

The inclusion of an acid wash in the post combustion capture process appears to offer a simple but robust catch all solution to this emerging issue. Further work needs to be done to establish how this should be implemented including whether a final water wash is needed. Development of this could be the domain of process licensors but this could be controversial given the additional cost and complexity implications. The programme should in the first instance promote adoption of a completely "clean" solution but could also consider commissioning an engineering contractor to further study and cost out suitable designs.

2012-08 CO_2 CAPTURE AT GAS FIRED POWER PLANTS

Background to the Study

Gas-fired power generation currently accounts for around 20% of global electricity production capacity and in the past twenty years it has been a popular choice for new power generation capacity, particularly in many developed countries, due to its high efficiency, low installed costs and good reliability and flexibility. Interest in natural gas fired power generation has increased recently because of the increasing availability of natural gas from shale and greater concerns about nuclear power in some countries.

A switch from coal to gas can help to reduce emissions from power generation substantially but it is not a CO_2-free generation option. In the longer term it is likely that new gas fired power plants will be required to be built and operated with CO_2 capture and storage (CCS) technology to achieve deep reductions in emissions. Most of the work on CCS has so far concentrated on coal and relatively little information on the performance and costs of gas fired power plants with CCS has been published. IEAGHG has therefore commissioned Parsons Brinckerhoff to undertake this techno-economic study on CO_2 capture at natural gas fired power plants.

Scope of Work

The study assesses the performance and costs of the following natural gas fired combined cycle power plants:

- A reference plant without CO_2 capture
- A plant with post combustion capture using non-proprietary MEA solvent scrubbing,
- A plant with post combustion scrubbing using an advanced proprietary amine solvent,
- A plant with recycle of cooled flue gas to the gas turbine inlet and post combustion scrubbing using MEA solvent,
- An integrated power plant with natural gas reforming and pre-combustion scrubbing,
- A plant with reforming, pre-combustion scrubbing, underground buffer storage of hydrogen-rich gas and a separate combined cycle plant.

The proprietary solvent case is representative of solvents being developed by various suppliers. Information was provided to the study contractor by MHI and Siemens but this case does not represent a specific proprietary technology.

The pre-combustion capture cases use air blown partial oxidation, shift conversion and CO_2 capture using Selexol solvent. In one of the cases the reformer and combined cycle power plant are integrated on one site. In the other case the reformer/CO_2 capture plant and the power plant are at separate sites and an underground salt cavern is used to provide 6 weeks of buffer storage of the hydrogen/nitrogen fuel gas. Information on the costs of underground hydrogen storage was provided by the study contractor based on their experience of building such facilities in the USA.

The technical performance of each plant was evaluated using process simulation and thermal plant simulation software (AspenPlus®, GTPRO®, GTMASTER® and Thermoflex®). Equipment lists and plant layout drawings were developed and these were used together with the contractor's in-house cost data and information provided by technology and equipment vendors, to develop high-level estimates of capital and operating costs. This information was subsequently used as inputs to an economic model which was used to evaluate the comparative economic performance of each plant and sensitivities to significant economic parameters.

The study report provides information on the designs of each of the plants, their power output, efficiency, greenhouse gas intensity, capital costs, operating and maintenance costs, levelised costs of electricity and costs of CO_2 avoidance. Process flow diagrams, stream data, equipment lists and plant layout diagrams are also provided.

Technical and economic basis

The technical and economic basis for the study is described in detail in the main study report. The main base case assumptions are:

- Greenfield site, Netherlands coastal location
- 2 GE9FB gas turbines + 1 steam turbine
- 9°C ambient temperature
- Mechanical draught cooling towers

- Base load operation
- Natural gas price: €6/GJ LHV basis (equivalent to €6.64/GJ HHV basis)
- 2011 costs
- 8% discount rate (constant money values)
- 25 year operating life
- 4 year plant construction time
- €5/t CO_2 storage cost
- €10/t CO_2 emission cost

Sensitivities to various economic parameters were evaluated, as discussed later.

The net power outputs of the plants are around 800MW but it was not possible to keep the net outputs the same in all of the cases because gas turbines are manufactured in fixed sizes and the ancillary steam and power consumptions are different in each of the cases, in particular they are substantially higher in the plants with CO_2 capture.

Levelised costs of electricity generation were calculated assuming constant (in real terms) prices for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from a lower capacity factor in the first year of operation. Costs of CO_2 avoidance were calculated by comparing the CO_2 emissions per kWh and costs of electricity (excluding any CO_2 emissions costs) of gas fired power plants with and without CO_2 capture. The cost of CO_2 avoidance would be different if an alternative baseline plant was used, for example a coal fired plant without capture.

Results and Discussion

Plant performance

The performances of the plants at base load are summarised in Table 1. Please continue to the next page.

				Efficiency		
	Net power output	CO_2 captured	CO_2 emissions	HHV	LHV	Efficiency penalty for capture
	MW	kg/MWh	kg/MWh	%	%	% points (LHV)
No capture	910	0	348	53.2	58.9	
Post combustion MEA solvent	789	365	41	46.1	51.0	7.9
Post combustion proprietary solvent	804	359	40	47.0	52.0	6.9
Post combustion MEA, flue gas recycle	785	362	41	46.4	51.3	7.6
Pre combustion	850	395	89	38.2	42.3	16.6
Pre combustion with hydrogen storage	737	454	104	33.2	36.8	22.1

Table 1 Plant performance

The efficiency penalty for conventional MEA post combustion capture comprises 4.8 percentage points for steam extraction for solvent regeneration, 1.3 percentage points for the capture plant auxiliary power consumption (mainly for the flue gas booster fan), and 1.7 percentage points for CO_2 compression. The proprietary solvent case has a lower efficiency penalty mainly due to a 19% lower steam consumption for solvent regeneration. The regeneration heat consumption of the proprietary solvent is 2700kJ/kg CO_2 captured.

The flue gas recycle case has a lower efficiency penalty than the conventional MEA case due to a 21% lower ancillary power consumption for the capture plant, which is mainly due to the lower flue gas fan power consumption, and a 6% lower steam consumption. These improvements are partly offset by a lower combined cycle plant efficiency due to the higher gas turbine compressor inlet temperature which results from the replacement of some of the air by warmer recycle flue gas. Flue gas recycle has been the subject of successful combustor tests by turbine manufacturers and it is being tested in a large commercial gas turbine. This study is based on 50% flue gas recycle to show the maximum potential for this technique but recycle may be restricted to lower levels depending on the design of the turbine combustors.

The pre-combustion capture cases have significantly higher overall energy consumptions than the post combustion capture cases. There is a wide range of design options for natural gas pre-combustion capture plants, including the type of oxidant (air or purified oxygen), the CO_2 capture solvent (chemical or physical solvent), the oxidant supply (from the gas turbine compressor or a separate compressor), and there are a wide range of heat integration options. The choice of design options depended on the contractor's judgement of the balance between efficiency, capital costs, percentage CO_2 capture, risk and operability. On balance it was decided to accept a lower percentage capture for the pre-combustion capture cases (about 81.5% compared to 90% for the post combustion cases) but it would be possible to design a pre-combustion capture plant for a higher capture rate if necessary.

Gas fired power plants with CCS are expected to operate at less than base load in future electricity systems that include large amounts of other low-CO_2 power generation (coal fired plants with CCS, wind, solar, nuclear etc), because the marginal operating costs of gas fired plants with CCS will usually be higher than those of the other technologies due to higher fuel costs. Gas fired power plant with CCS will therefore need to be able to operate flexibly and at lower annual capacity factors. IEAGHG has recently published a report on the operating flexibility of power plants with CO_2 capture , so to avoid duplication another detailed assessment of flexibility has not been undertaken. However, this study does assess plant performance and efficiency at part load (40% gas turbine load, corresponding to about 50% overall net output). At this part load condition the thermal efficiencies of plants with and without post combustion capture were estimated to be 6 - 7 percentage points lower than at 100% load . It should be noted that in many cases a gas fired power plant would not spend a substantial fraction of its time operating at low load even if it operates at a low annual average capacity factor. For example a plant with a low capacity factor may spend much of its time operating at either high load or shut down, rather than operating continuously at part load, to avoid incurring the part load efficiency penalty.

Base case costs

Capital costs of power plants with and without CO_2 capture are shown in Table 1. The costs are expressed as EPC (Engineering, Procurement and Construction) costs excludes owner's costs and interest during construction, although these extra costs are taken into account in the calculation of levelised costs of electricity (LCOE). The LCOEs are for base load operation and include costs of CO_2 transport and storage and CO_2 emission costs. The annual capacity factors are assumed to be 93% for the plant without capture, 90% for plants with post combustion capture and 85% for plants with pre-combustion capture, in line with the expected differences in plant availabilities. The cost of CO_2 emission avoidance is the carbon emission cost that would be required to give the same electricity cost for power plants with and without CCS.

The proprietary solvent and flue gas recycle cases both have significantly lower costs than the conventional MEA base case, mainly due to their higher thermal efficiencies, smaller equipment sizes and, in the case of the proprietary solvent, lower solvent costs. It would be possible to combine flue gas recycle and a proprietary solvent and this is expected to achieve an even higher efficiency and lower costs. This case was beyond the scope of this study but it could be considered as part of a future study.

The pre-combustion capture cases have significantly higher costs than the post combustion capture cases. Costs of the pre-combustion case with hydrogen/nitrogen fuel gas storage are shown at base load in Table 1 for consistency with the other cases but it is recognised that this configuration's main advantages will be for lower annual capacity factors, which are discussed later in the section on cost sensitivities. The reason for the higher capital cost

[1] Operating flexibility of power plants with CCS, IEAGHG report 2012/6, June 2012.

[2] The part load efficiency penalty may be different for gas turbines from other manufacturers.

of this plant compared to the pre-combustion capture plant without storage is the cost of the storage facilities, which is equivalent to €218/kW, and the extra costs associated with having separate reforming/capture and power plants.

Breakdowns of the levelised costs of electricity are shown in Figure 1. It can be seen that in all cases the main contribution to the electricity cost is the fuel cost. The fuel costs are higher in the plants with capture due to their lower thermal efficiencies but the main reason for the higher overall costs is the higher capital charges.

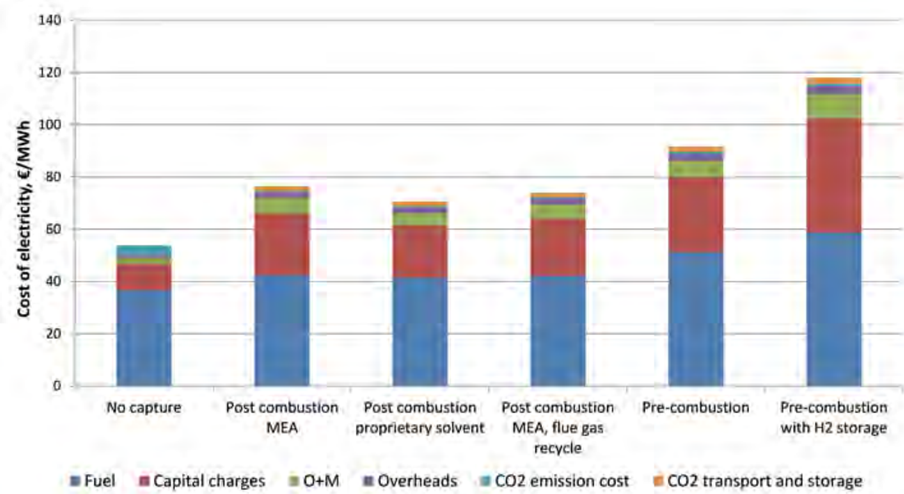


Figure 1 Levelised costs of electricity, base load operation

Cost sensitivities

Cost sensitivities were evaluated for all of the plants. Results for the plant with post combustion capture using a proprietary solvent are shown as an example in Figures 2 and 3, where costs of electricity and CO_2 abatement are shown for high, medium and low values of each parameter. Results for the other plants are given in the detailed study report.

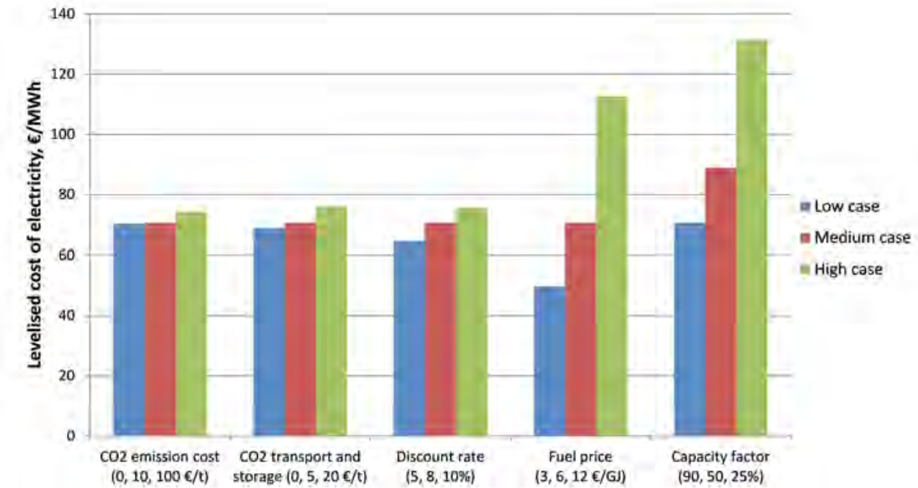


Figure 2 Electricity cost sensitivities (post combustion capture, proprietary solvent)

The electricity cost is most sensitive to the fuel price and the annual capacity factor. The wide range of fuel prices assessed in this study (3-12 €/GJ) represents the high degree of uncertainty regarding future gas prices and regional price differences.

The base case cost of CO_2 transport and storage was assumed to be €5/t of CO_2, which may represent a cost of on-shore storage close to the power plant. A zero (or even negative) net cost may apply if the CO_2 could be utilised for enhanced oil recovery (EOR). An increase to €20/t, representing offshore storage at a significant distance from the power plant, is shown to have a relatively small impact on the cost of electricity. Gas fired power plants have an advantage over coal fired plants in this regard because only about half as much CO_2 has to be stored per MWh.

Decreasing the capacity factor from 90% to 50% has a relatively modest impact on costs but a further reduction to 25% has a substantially greater effect. It should be noted that most of the alternative technologies for low-CO_2 electricity generation (renewables, nuclear etc.) have relatively high fixed costs, so their electricity costs will increase more steeply as the annual capacity factor is reduced. This should give gas fired plants with CCS a competitive advantage for intermediate load generation, which accounts for a significant fraction of overall electricity generation. For the purposes of the assessment of the sensitivity to annual capacity factor it is assumed that the plant is operated for part of the time at full load and for the rest of the time it is shut down, although in practice a plant may spend some time operating at part load. The costs do not include costs of start-up and shutdown and increased costs for part-load operation because evaluation of these costs was beyond the scope of this study and they would depend on the operating schedule of the plant.

The base case assumption for the CO_2 emission cost (€10/t) broadly represents current typical emission costs within the EU, although it is recognised that this is less than the cost that would be required to make CCS economically attractive. It can be seen that even an increase to €100/t would have only a small impact on the cost of electricity generation with CCS because it would only apply to the 10% of CO_2 that is not captured.

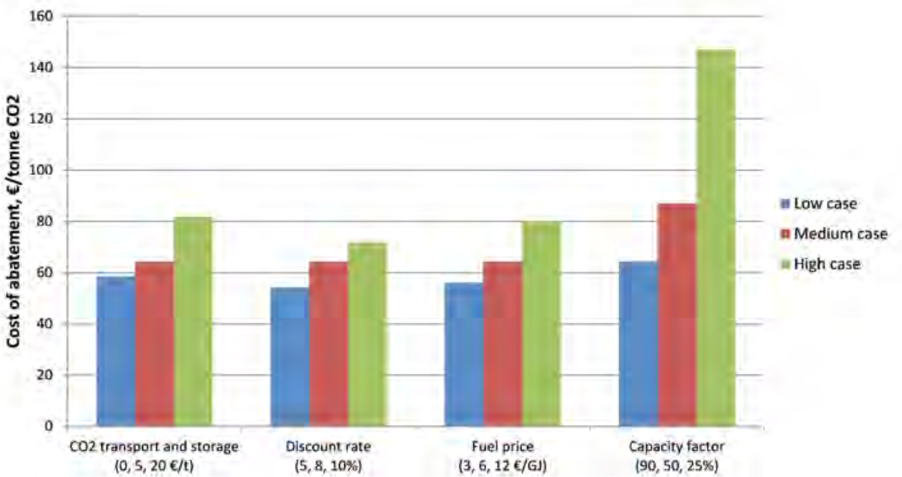


Figure 3 CO_2 abatement cost sensitivities (post combustion capture, proprietary solvent)

The CO_2 abatement costs shown in Figure 3 are mostly within a reasonably narrow range, between about 55 and 85 €/t CO_2, even for the wide range of sensitivity values considered in this study. This is because the parameter sensitivities (apart from the CO_2 transport and storage cost) affect the costs of the reference plant without capture as well as the plant with capture.

Combinations of sensitivity values may of course result in abatement costs outside of this range. The only exception is the 25% capacity factor case, where the costs are substantially higher.

Because gas fired power plants are generally expected to operate at less than base load the sensitivity to capacity factor is particularly important, so costs of electricity for all of the cases at base load, 50% and 25% capacity factor are presented in Figure 4.

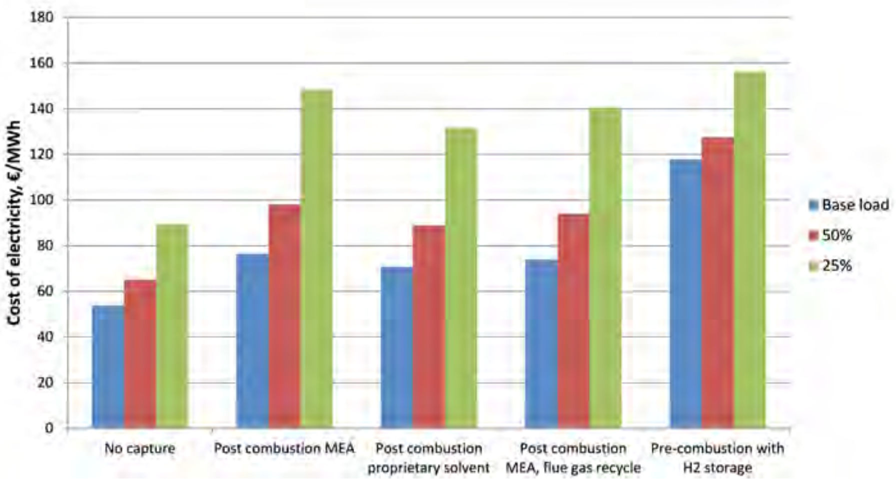


Figure 4 Sensitivity to annual capacity factor

At 25% capacity factor the costs of post combustion capture and pre-combustion capture with hydrogen storage are broadly similar . Earlier work by IEAGHG indicates that pre-combustion capture with hydrogen storage is a more attractive option for coal fired plants and the economic breakeven with post combustion capture occurs at a significantly higher annual capacity factor. It is therefore recommended that further work on the hydrogen storage option should be focussed on coal or biomass fired plants.

Plant layout and area requirements

Plot sizes for each of the plants are given in table 3 and typical layout diagrams are included in the main study report. The addition of post combustion capture increases the plant area requirement by about a third and pre-combustion capture approximately doubles the area requirement.

No capture	Plot size (m)	Area (ha)
No capture	360 x 250	9
Post combustion capture	490 x 250	12
Post combustion capture with flue gas recycle	480 x 250	12
Pre-combustion capture	440 x 390	17
Pre-combustion capture, separate sites:		21
Reformer plant	360 x 350	
Power plant	360 x 250	

Table 3 Plant areas

Expert Review Comments

Comments on the draft report were received from reviewers in the power industry and research organisations who have worked on post and pre combustion capture at natural gas fired power plants. Comments on some aspects of the report were also received from post combustion capture technology vendors. Changes were made to take into account reviewers' comments. The contribution of the reviewers is gratefully acknowledged.

In general the reviewers thought the report was of a high standard and the results were broadly consistent with the results of other recent studies on CO_2 capture at gas fired power plants. Some reviewers emphasised the importance of operational flexibility of NGCC plants and asked for more information on this subject. This has partly been covered by a separate IEAGHG report on operational flexibility of power plants with CCS and further work on this subject could be carried out in future. To help to address the comments greater emphasis was given in the overview to operation at low capacity factors.

[1] The costs presented in this overview are based on the assumption that the pre-combustion capture case with hydrogen storage includes a single reforming and capture plant which operates continuously and which provides fuel gas to multiple combined cycle plants operating at lower annual capacity factors. In the main study report it is assumed that the reformer and capture plant would feed only one combined cycle plant and the reformer would also operate at 25% capacity factor.

[2] Flexible CCS plants, a Key to Near-zero Emission Electricity Systems, J. Davison, Energy Procedia 4 (2011) 2548-2555.

Conclusions

- Adding post combustion capture reduces the thermal efficiency of a natural gas combined cycle plant by about 7-8 percentage points, increases the capital cost per kW by about 80-120% and increases the cost of base load electricity generation by about 30-40%.
- The cost of CO_2 emission avoidance (i.e. the carbon emission cost required to give the same electricity cost from base load NGCC plants with and without CCS) is about €65/tonne in the lowest cost case evaluated in this study (post combustion capture with a proprietary solvent). The abatement cost compared to an alternative base line such as a coal fired plant may be lower.
- Recycling part of the cooled flue gas to the gas turbine compressor inlet would increase the CO_2 concentration in the feed to the CO_2 capture unit, which could increase the thermal efficiency by up to 0.3 percentage points and reduce the cost of electricity by up to 8 percent.
- Natural gas combined cycle plants with CCS may operate at annual capacity factors lower than base load, particularly in electricity systems that include large amounts of other low-CO_2 generation. In the lowest cost case, reducing the annual capacity factor to 50% would increase the cost of CO_2 avoidance to €87/tonne.
- The study indicates that, based on current technology, pre-combustion capture in natural gas fired combined cycle power plants is not economically competitive with post combustion capture.

Recommendations

- This study could be extended to assess a combination of a high efficiency proprietary post combustion capture solvent and gas turbine flue gas recycle.
- The performance and costs of natural gas fired power plants with other CO_2 capture technologies such as other liquid solvents, solid sorbents or membranes should be evaluated if sufficient input data become available.

- Further work should be undertaken to assess the operation of gas fired power plants with CCS in future electricity systems that include large amounts of other low-CO_2 generation technologies.
- IEAGHG should undertake a new study to assess the performance and costs of baseline coal fired power plants with CO_2 capture.

2012-02 QUANTIFICATION TECHNIQUES FOR CO_2 LEAKAGE

Background

On the whole, the primary focus of CO_2 storage monitoring techniques has been to monitor plume behaviour in storage formations, and to detect leakage to the biosphere. However, for emissions trading under the EU ETS and for national GHG inventory purposes it is necessary to quantify leaked emissions to the atmosphere should leakage occur, and there is a low level of understanding of the capabilities, accuracies and uncertainties of measurement techniques for this application. Quantification of leakage was identified as a significant gap in the knowledge base of the IEAGHG storage networks at the Joint Network Meeting in June 2008, and the IEAGHG Environmental Impacts of Leakage workshop held in September 2008 highlighted potential for quantitative measurements to a level of accuracy required although inconclusive. Both the EU ETS work on monitoring and reporting guidelines for CCS and the EU CCS Directive working group concluded there is insufficient knowledge in this area; hence, it is pivotal for policy, regulations and for the development of monitoring technologies to ascertain the current state of knowledge in this field and understand possible future developments to meet requirements.

Scope and Methodology

A contract for this study was awarded to CO_2GeoNet, with a project team led by Imperial College, London. The primary aim was to identify potential methods for quantifying CO_2 leakages from a geological storage site from the ground or seabed surface. The contractor was asked to review and identify techniques that have the potential to measure CO_2 leakage into the atmosphere and into the water column, for both point-source and dispersed leakage scenarios; once identified, provide a detailed review of quantification performance including sensitivity cost and future developments; suggest quantification improvements of a monitoring portfolio; review current requirements and, provide recommendations. The contractor was also asked to liaise with the British Geological Survey to ensure results are reflected in the updated IEAGHG Monitoring Selection Tool.

The contractor provides a description of the technologies that can measure CO_2 leakage from potential point and/or diffuse sources, reviewing the quantification performance of these methods, discussing potential improvements for quantifying CO_2 leakage through the implementation of a monitoring portfolio approach. The review focusses on methods relevant for monitoring the marine and terrestrial aquatic environments, the atmosphere, shallow subsurface and ecosystems for leaked emissions as defined for requirements in the EU ETS and GHG inventory guidelines; recognising the importance of deep subsurface monitoring techniques to identify potential pathways and migration in advance which are briefly discussed as part of monitoring portfolios.

Results and Discussion

Techniques to detect and quantify CO_2 leakage

Due to the nature of a CO_2 geological storage site, techniques to detect any potential leakage or likely pathway will be necessary prior to deployment of direct or indirect instrumentation for quantification. Deep subsurface methods will therefore be important to identify any potential leakage before it reaches the near subsurface, atmosphere or water column. Baseline monitoring is needed before any compartment is altered by the effect of CO_2 injection or exposure, especially as large spatial and temporal variation of background levels is likely to contribute the largest level of uncertainty. Modelling is also key to the planning of monitoring programmes; hence methods to help constrain model parameters and reduce uncertainties will add value. Preference should be given to methods that are concurrently employed for performance monitoring, are favourable in terms of cost and benefit, are most reliable and accurate, can be deployed in conjunction with other techniques, can be operated with minimum human effort, are robust and have added benefit in improving calibration of models. Detectability and sensitivity of a monitoring method is not just dependant on the technology but also the implementation mode when used in a specified calibration range and of course, different technologies will be suitable for different conditions and environments.

*Note all references are provided at the end of the full report

Table 1 presents the suitability of available methods for CO_2 detection and quantification considering the rate of CO_2 that can be quantified using the proposed techniques.

Table 1. Suitability of available monitoring methods for detection and quantification of CO_2 leakage from a storage site

AQUATIC MONITORING / Leakage quantification	Monitoring method	Sonar methods: Sidescan sonar bathymetry	Sonar methods: Seabed multibeam bathymetry	Sonar methods: Bubble stream detection	Surface water chemistry	Marine Bubble stream chemistry
Leakage rate	low (100 g/d)					
	intermediate (100 kg/d)				*case dependent*	
	high (100 t/d)					
Leakage type	diffuse	*case dependent*	*case dependent*		*case dependent*	
	disperse spots					
	single localised leak	*case dependent*	*case dependent*			

ATMOSPHERIC MONITORING / Leakage quantification	Monitoring method	Long open path (IP diode lasers)	Short open path (IR diode lasers)	Short closed path (NDIRs and IR)	Eddy covariance
Leakage rate	low (100 g/d)				
	intermediate (100 kg/d)	*case dependent*			
	high (100 t/d)				
Leakage type	diffuse	*case dependent*	*depends on contrast with background*	*case dependent*	
	disperse spots				
	single localised leak				

SHALLOW SUBSURFACE MONITORING / Leakage quantification	Monitoring method	Soil gas and flux	Downhole fluid chemistry	Hydrochemical methods	Tracers	Soil geochemistry
Leakage rate	low (100 g/d)	*dependant on size of mofette and back-ground level/fluctuations*		*localised discharge from fractured reservoirs only*		
	intermediate (100 kg/d)					
	high (100 t/d)					
Leakage type	diffuse	*dependant on contrast of leakage anomaly/background*		*low rates may not be detectable*		
	disperse spots					
	single localised leak		*require large fluxes and extensive geoch.anomalies*			

ECOSYSTEMS MONITORING / Leakage quantification	Monitoring method	Terrestrial ecosystems	Marine ecosystems
Leakage rate	low (100 g/d)		
	intermediate (100 kg/d)	*case dependent*	*case dependent*
	high (100 t/d)		
Leakage type	diffuse	*case dependent*	*case dependent*
	disperse spots		
	single localised leak	*case dependent*	*case dependent*

pink = method suitable; yellow = less suitable; white = not applicable

REMOTE SENSING / Leakage quantification		Monitoring method: Airborne and satellite spectral imaging	Airborne EM
Leakage rate	low (100 g/d)		
	intermediate (100 kg/d)		*case dependent*
	high (100 t/d)		
Leakage type	diffuse		*case dependent*
	disperse spots		
	single localised leak		*case dependent*

pink = method suitable; yellow = less suitable; white = not applicable

Marine and terrestrial aquatic environment monitoring

CO_2 once in the water column will be rapidly dispersed by currents or dissolution and dilution. An understanding of baseline concentrations and variability as well as the local physical oceanography is crucial for interpretation of monitoring data. As there is likely to be a small signal in a large volume of water, methods with large spatial coverage provide the opportunity to detect but may be limited for quantification due to poor resolution; therefore monitoring strategies may be designed to focus on detection initially, and if a leak is suspected then techniques for flux quantification may be deployed. Side scan sonar was initially deployed from ships, and later applied to towed vehicles and autonomous underwater vehicles (AUV). The bathymetric data is obtained by active sonar, generating high quality images which can resolve features as small as 1cm; hence can detect small changes in morphology should seabed surface topography be effected by any potential CO_2 leakage. Side scan sonar could also be used to detect CO_2 seeping into the water column: demonstrated in natural seepage of shallow methane gas. With high sensitivity they have been identified to have high potential for subsea hydrocarbon leakage detection systems (Carlsen and Mjaaland, 2006), with coverage in the range of some tens of metres for subsea oil and gas production systems (Hellevang et al., 2007), and such could be adapted for CO_2 leakage monitoring, as demonstrated in deep sea environments (e.g. Brewer et al, 2006).

Sonar system surveys, which are likely to be cost-effective, have the potential of covering a wide spatial area in a short period of time, and applying such to AUVs may be promising for monitoring, detecting and further quantification though multibeam systems may have limited resolution. High resolution

(HR) reflection profiling methods are particularly sensitive to gas as source frequencies overlap resonance frequencies of naturally-occurring bubbles; hence with multifrequency surveys may have potential for gas flux estimates and quantification of gas content if combined with stream chemical analysis, though have limited penetration. Combining multibeam sonar with optical methods, acoustic tomography and flow sensors could assist in quantification of flux, and a swarm of AUVs equipped with multibeam sonar and sensors could survey a large area on a regular basis which though costly would be effective. Long-term in-situ monitoring however requires a stationary system such as GasQuant: a lander based hydroacoustic swath system developed to monitor temporal variability of bubble release at seep, recording bubbles crossing the horizontally orientated swath, capable of monitoring an area of 2km2. An energy supply is of course crucial for any long term system and a system such as GasQuant could be linked to storage technical installations. With areal coverage of thousands of square kilometres, the Long Range Ocean Acoustic Waveguide Remote Sensing (OAWRS) for bubble detection may be suitable for initial surveys though has low resolution therefore would be limited for detailed quantification.

Geochemical methods are the only techniques that can directly quantify CO_2 seepage in the form of bubbles which dissolve as they rise or as dissolved CO_2 migrating with deep-origin waters. Composition of the leaking gas may elucidate its source and help determine the flux rate and, samples of the gas can be collected and analysed close to the potential leakage point before dissolution into the water column; either in-situ or in the laboratory with leakage rates estimated by conducting profiles and using associated current velocities to calculate mass flux. Laboratory analysis is useful for improved sensitivity or for analysing components in-situ, though in situ analysis reduces potential sampling artefacts and as a continuous method has the possibility of collecting large amounts of data. A CTD probe is commonly used for measurements such as these, however ROVs are more flexible, and equipped with sensors, an ROV can be deployed once sonar has identified a possible leakage site, measuring the size and shape of plume by manoeuvring the ROV in and out of the plume; or if also equipped with scanning sonar, can potential map the plume. Cost effective mini-ROVs are now available such as the Ocean Modules V8 Sii (€120k-€200k depending on the configuration). Alternatively, sensors could be mounted on AUVs offering good spatio-temporal resolution. Various types of sensors have been applied for commercial and research probes including non-dispersive infrared (NDIR), electrochemical, mass spectrometers, direct-absorption spectroscopy and calorimetric sensors. An example of such sensors is the SAMI2; which uses a diffusion membrane and a wet chemical approach, as the dissolved CO_2 diffuses across the membrane onto a pH indicator where it transforms into carbonic acid, changing the solution pH; and can measure pCO_2 in the range of 150 to 750ppm, with a response time of 5 minutes, precision greater than 1ppm, accuracy of ±3ppm, long term drift of less than 1ppm in 6 months, and can be deployed up to 500m depth. There is extensive development of in-situ sensors and autonomous marine platforms that show promise for the future.

A technique lying between in-situ and remote analysis of dissolved gas is the equilibrator technique with good spatio-temporal coverage, involving the towing of a long hose behind a ship, with a 'fish' at the end of the hose which maintains a constant sampling depth and a pump which continuously transfers water to the ship, passing it through the equilibrator which strips dissolved gases from the water for analysis via either infrared or gas chromatography. This method has been used for the detection of pipeline leaks and seepages from oil and gas reservoirs (e.g. Logan et al., 2010; Figure 1).

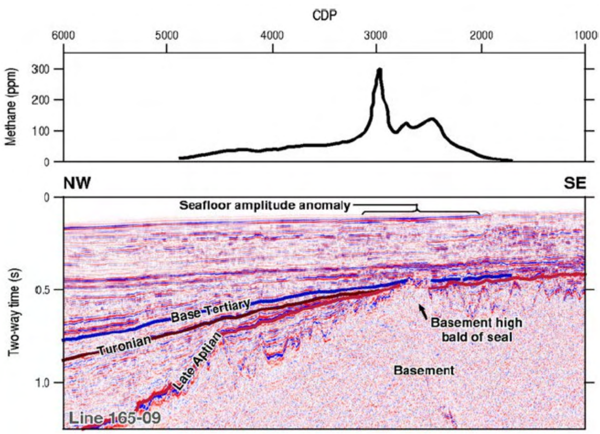


Figure 1. Dissolved CH_4 concentration profile conducted with an equilibrator system above a known gas field (Logan et al. 2010).

Benthic chambers also offer potential for direct quantification of flux rates from the sediment to the water, which consist of an enclosed volume with one end open for deployment on the sediment surface by divers in shallow water or ROVs or landers. However, these measurements are highly point specific and errors can occur due to spatial heterogeneity. As elevated CO_2 levels near the seabed and in ambient water will affect marine ecosystems, monitoring of seabed fauna could also be measured using AUVs or long-term time lapse video recording. Threshold values currently being researched in projects, such as the EU FR7 Research into Impacts and Safety of CO_2 Storage (RISCS) and ECO_2 (Sub-seabed CO_2 Storage: Impact on Marine Ecosystems), may represent a useful tool for the evaluation of biological impacts and in turn, quantification of potential CO_2 leakage.

Atmospheric monitoring

Similar to the marine environment, leaked emissions of CO_2 to atmosphere may be quickly dispersed, and may prove difficult to detect using techniques favouring wide areal coverage and low spatial resolution. Surface monitoring instrumentation is therefore best placed in areas where potential leakage pathways have been identified during risk assessments. There are a number of techniques tested and in development with potential for quantification of CO_2 flux, including the eddy covariance method (ECM) and long open path diode lasers.

The eddy covariance method offers relatively large spatial coverage, using statistics to compute turbulent fluxes of heat, water and gas exchange, and is one of the most effective methods to measure and determine gas fluxes in the atmospheric boundary layer; and has been proposed as a potential method for monitoring CO_2 storage sites (e.g. Oldenburg et al., 2003). ECM is an established technique with low to moderate costs largely associated with the requirement of significant specific knowledge regarding the application of mathematical corrections and processing workflows. ECM works by a gas flux determined as a number of molecules crossing a unit area per unit time, and the gas flux is based on the covariance between concentration and vertical air movement/speed. Measured flux rates lie within the typical range of natural CO_2 emissions from soils and land cover (tens of g/m2/d) and higher emission rates can be easily determined, e.g. Werner et al. (2003) measured release rates between 950-4460 g/d/m^2 at the Solfatara volcano, Sicily. However, whether ECM can detect potential leakage from a storage site depends on the ratio between the integral CO_2 flux from the footprint area and the seepage rate from the point source, for example seepage rate of 0.1 t/d from a Zero Emission Research and Technology Center (ZERT) release experiment wasn't distinguishable from background CO_2 emissions, whereas a release of 0.3 t/d significantly increased the flux compared to the baseline (Lewicki et al., 2009).

With a finer spatial resolution than ECM, various open-path sensing techniques have been developed, measuring path-integrated concentration of a target gas between two points near the ground surface, with a measurement interval ranging from tens to hundreds of metres. These methods have been used to locate gas emission and estimate leakage rates to atmosphere from point or non-point sources such as landfills and coal mines (e.g. Piccot et al., 1996; EPA, 2006); and more recently have been applied to monitoring of CO_2 geological storage sites (e.g. Trottier et a., 2009). There are a number of different systems, including Open Path Tuneable Laser (TDL) and Open Path Fourier Transform Infrared (FTIR) which to date have been applied to CO_2 monitoring. As the location and quantification of various gaseous pollutants is an issue, not only for CO_2 monitoring, the US EPA has published a protocol for the use of open path optical techniques applied to emission monitoring (EPA, 2006). Longer path lengths ensure larger areas are monitored; however also result in loss of resolution and greater dilution of the leakage signal, therefore shorter path lengths are beneficial highlighting this method requires identification of a defined location. The method is well adapted for long-term unattended monitoring, as the lasers can be mounted on automated rotating platforms and most have an internal reference cell for self-calibration.

Leakage quantification can be performed on the resultant data from open-path sensing measurements by applying models such as vertical radial plume mapping (VRPM) (EPA, 2006); which employs multiple non-intersecting beam paths in a vertical plane down-wind from a leak to define a plume map, and the flux through the vertical plume is calculated by combining the plume map with the wind speed and direction. Another approach using a background Lagrangian stochastic (bLS) model (particle tracking) appears the most promising; assuming all required wind statistics can be determined from a few key surface parameters; and is valid when source and measurement point lie within a horizontal homogenous surface layer and, distance between these two points is sufficiently short that the particles remain in this surface layer. Controlled methane release experiments have yielded estimates within 5% of the true value at flux rates of 16-48 t/day (Flesch et al., 2004) and 3-6 t/day (Loh et al., 2009), in agreement with modelled minimum detectable rates of 1.7-7 t/day (Trottier et al., 2009; compared with modelled minimum detectable flux rates of 950 – 3800 t CO_2/day (Trottier et al., 2009) and an over estimation by 87% during controlled leakage of 43-100 t CO_2/day (Loh et al., 2009); hence similar results with CO_2 have produced larger errors due to more background variability and lower sensor sensitivity.

Short open-path lasers are very similar to long open-path, with the difference of the equipment being mounted on ground or airborne vehicles for mapping of point sources compared to fixed installations; with TDL the most commonly applied method for CO_2 monitoring. Response times are rapid with little memory effects hence can be conducted at high speeds. Although the CO_2 unit is less sensitive than for CH_4 the sensor has undergone recent technological advances, improving performance, and the tuneable diode laser can now measure up to an IR absorption band of 2000 nm, enabling 5 ppm CO_2 sensitivity and a range of 10,000 ppm. The ground based CO_2 unit measures once every second at recommended speeds of 20 to 100 km/h. Such has been tested at natural seepage sites such as Latera, Italy and Laacher

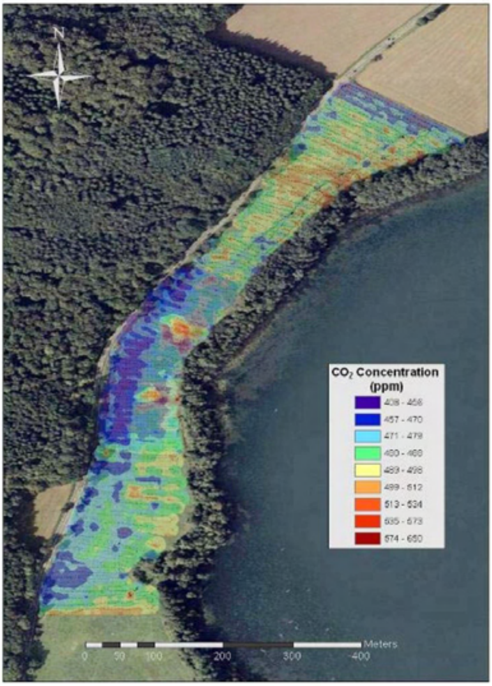


Figure 2. CO_2 concentrations in the air measured at about 30 cm height using a mobile, short open path infrared laser system, Laacher See, Germany (Jones et al. 2009).

See, Germany: Figure 2 (Jones et al., 2009; Kruger et al., 2009); as well as during surface gas monitoring at the In Salah Gas project in 2009 using a Boreal Laser open path CO_2 detector linked to a GasFinder FC, mounted at 38cm above the ground on a Toyota Landcruiser, which used a detector wavelength of 2 µm with a 5-10ppm CO_2 sensitivity (Jones et al., 2011). Airborne methods for CO_2 detection and quantification may prove difficult due to low sensitivity, the influence of wind conditions and the tendency for CO_2 to remain closer to ground level.

Short closed-path detectors involve the introduction of a gas sample into a chamber via a pump or diffusion and the quantification of a specific gas component by passing light across the chamber and through the sample. This is similar to long and short open path laser due to the use of optical sources and detectors, but differs due to the measurement chamber, allowing for greater portability and reduced interference though can have lower sensitivity and a slower response time. As they are of relatively low cost, are flexible, robust and could be deployed in large numbers, they show promise for use in a monitoring network. It consists of an infrared source and an infrared detector separated by a measurement cell, with recent advances including an internal reference cell for calibration. There are two types of infrared detectors: non-dispersive (NDIR) and dispersive. In NDIR, all the light from the source passes through the sample, after which it is filtered prior to detection; however in a dispersive system a grating or prism is used prior to the sample to select a specific wavelength. NDIR are the most commonly used detectors for field application and are often used in soil gas and CO_2 gas flux surveys which is discussed in Shallow Subsurface monitoring.

In terms of atmospheric monitoring, Lewicki et al. (2010) concluded NDIR sensors showed great promise if deployed around areas of higher potential for leakage, and Loh et al. (2009) showed an enrichment of greater than 4 ppm above background levels for CO_2 was needed for detection and quantification of CO_2 flux, in comparison with CH_4 which only required an enrichment of 0.02 ppm. Additionally, Wimmer et al. (2011) noted elevated concentrations were not observed at heights greater than 2.5 cm except directly above the leakage point when deploying NDIR; highlighting detecting and quantifying CO_2 flux may be challenging. Short closed path tuneable diode lasers (TDL) can have better sensitivities and faster response times, with the added benefit of the potential for real-time isotopic analysis; however these tend to be more expensive.

Shallow subsurface monitoring

Near surface gas chemistry offers two relatively low cost methods of monitoring and quantifying CO_2 leaked emissions: gas flux measurements at the ground surface and gas concentrations or isotopes in the shallow sub-surface (typically from a depth between 0.5 and 1m), and are commonly deployed together. Gas flux measurements are generally conducted using either the closed chamber (CC) or dynamic closed chamber (DCC) techniques, involving monitoring of gas changes over time within an accumulation chamber placed on the soil surface, with samples collected manually in the CC method or continuously (commonly every second) via an in-line detector in the DCC method and such autonomous monitoring can be very valuable for collecting baseline data.

Soil gas samples are typically collected using small lightweight soil probes, involving driving a hollow steel tube into the ground and drawing soil air to the surface for analysis, or alternatively, sampling methods involve direct push, power hammered, augured or drilled systems but these are more costly, less portable and slower. In dry permeable ground such as in arid environments, deeper sampling at several metres depth may be essential to avoid atmospheric contamination (Gole & Butt, 1985). The samples can be analysed in the field, using portable equipment or stored in airtight containers for laboratory analysis, examining CO_2 plus other gases due to possible association with the reservoir (e.g. CH_4), as well as performing isotopic analysis to determine the origin of the gas i.e. to distinguish between naturally occurring CO_2 and that which may be originating from storage the reservoir. However, CO_2 isotopes may be limited as delta 13 Carbon values of CO_2 from burning of fossil fuels are similar to those from plant or microbial respiration; hence tracers are being examined for monitoring and quantification purposes, for example at the West Pearl Queen depleted oil formation in SE New Mexico study site where a Perflourocarbon tracer (PFT) was added to injected 2,090 tonnes of CO_2 and was used to quantify a CO_2 leakage rate of 2.82 x 103 g CO_2/yr (Wells et al., 2007).

Two main factors influence the success of soil gas and gas flux surveys for quantification: the methods much locate the leak and define its physical extent which can be addressed statistically, and the methods must be able to separate baseline flux from leakage flux rates for which baseline subtraction approach can be used or analysis for tracer species in soil gas which can be associated with the injected CO_2 and relating their concentration to CO_2 at the surface. Timeliness is also key hence it is important soil gas and gas flux measurements are integrated into a wider monitoring program. Sampling on a grid, interpolating between points, conversion to total flux for the measurement area and subtracting near-surface contributions, would typically be the process for quantification, for example, controlled leaks of 0.1 and 0.3 t CO_2/d at the ZERT site were accurately quantified with the latter 0.3 t CO_2/d leak quantified at a mean ± 1 standard deviation of 0.31 ±0.05 t CO_2/d (Lewicki et al., 2010).

In the near surface environment, CO_2 flow is likely to occur as bubbles migrating vertically along a fault or borehole, and in such a case, gravimetric and Elecromagnetic (EM) / Electrical Resistivity Tomography (ERT) methods may be deployed whilst simultaneously monitoring the reservoir, and can potentially be used for detection in groundwater. Continuous or time-lapse gravimetric methods may theoretically be able to characterise volumes of gas in the order of a few hundreds of tonnes in the shallow subsurface depending on saturation, though it is not established for CO_2 monitoring and may be prohibitively expensive. Airborne EM is well established in groundwater exploration studies (e.g. Siemon et al., 2009) however applicability may be limited due to noise from a variable water table and high natural CO_2 flux. Ground-based sampling would be needed to establish the cause of any enhanced conductivity, and for quantification a numerical simulator could be used to predict the groundwater impact of an ingression of CO_2 in terms of a change in total dissolved solids (TDS), using an empirical relationship between TDS and EM to estimate the amount of CO_2 dissolved in the groundwater which is a subject of current research.

Hydrochemical factors may be useful for both detection and quantification, particularly in inhabited areas with springs or streams, for example waters with elevated CO_2 levels emerging at the surface may visibly show signs such as bubbles or rusty deposits through mobilisation of iron and oxidation at the surface. Depending on the water composition, CO_2 may form numerous dissolved complex species which can be sampled and analysed. The relative accuracy of hydrochemical analyses is in the order of 1-3%, with detection limits of CO_2 being 2 mg/l and 3 mg/l for HCO_3^-. However, quantification into shallow groundwater is subject to a number of uncertainties, requiring dense and repeated sampling to reduce such uncertainties, and the accuracy of quantification required is unlikely to be sufficient for emissions accounting.

Ecosystem and Remote sensing monitoring

Ecosystem-based monitoring can be used to quantify and detect potential leakage into near surface environments, particularly when undertaken in combination with soil gas surveys, though accuracy necessary to meet requirements may be difficult. Botanical, soil gas, microbiological and gas flux surveys at the natural CO_2 seepage site at Latera has observed significant impact in a zone a few metres wide centre of the vent, with acid tolerant grasses dominating near the vent core, microbial populations regulated by near anoxic conditions, and small changes in mineralogy and bulk chemistry (Beaubien et al., 2008). Such impacts on vegetation and soil geochemistry may possibly be detected using airborne spectral (or optical) remote sensing techniques (Chadwick et al., 2009). Thermal imaging may also potentially detect leakage if there is a measurable temperature anomaly. Higher spectral resolution is achieved with hyperspectral sensors which can be as precise as 1m. Bateson et al. (2008) used spectral datasets to assess several indices related to plant stress and estimated a threshold of around 60 g m-2 d-1 would be the minimum CO_2 flux rate that could be detected with spectral remote sensing methods (Figure 3). Such vegetation indices can however contribute to false positives and hence care should be taken on interpretation.

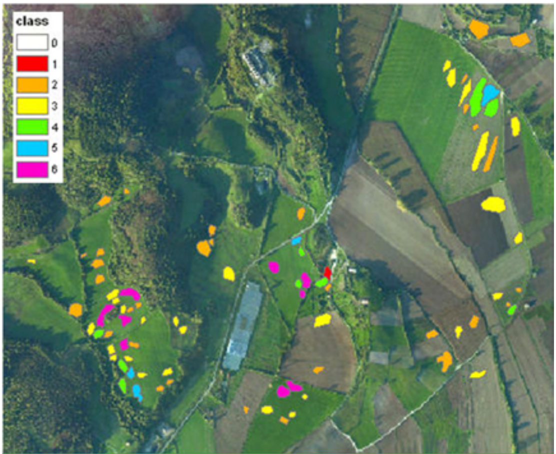


Figure 3. Map of possible CO_2 leakages in the Latera caldera (After Bateson et al., 2008). The polygon colours correspond to the number of datasets (methods) that showed an anomaly within that polygon.

CO_2 Leaked Emissions Requirements

Under EU regulations, requirements for leaked emissions falls under the EU Emissions Trading Scheme (EU ETS) (Directive 2003/87/EC); which, operating since 2005, builds upon mechanisms set up under the Kyoto Protocol, the Clean Development Mechanism (CDM) and Joint Implementation (JI) (EC, 2008); and for geological storage of CO_2 would now be triggered by the EU CCS Directive which entered into force in 2009. Article 16 of the EU CCS Directive 2009/31/EC lays out requirements in case of leakages or significant irregularities, ensuring should there be any leaked emissions there would be a surrender of allowances under the EU ETS. In June 2010, Decision 2007/589/EC (establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC) was amended to say leakage 'may be excluded as an emission source subject to the approval of the competent authority, when corrective measures pursuant to Article 16 of Directive 2009/31/EC have been taken and emissions or release into the water column from that leakage can no longer be detected.' A further amendment to Decision 2007/589/EC under Annex XVIII adds 'Monitoring shall start in the case that any leakage results in emissions or release to the water column. Emissions resulting from a release of CO_2 into the water column shall be deemed equal to the amount released to the water column' and defines an approach for quantification, stating 'The amount of emissions leaked from the storage complex shall be quantified for each of the leakage events with a maximum overall uncertainty over the reporting period of ± 7.5%. In case the overall uncertainty of the applied quantification approach exceeds ± 7.5%, an adjustment shall be applied'. The operator requirements for acknowledgement of uncertainties, using a cumulative approach as defined in the 1996 IPCC Guidelines indicates the greater the uncertainty the greater the penalty should CO_2 leakage occur.

Currently, there are no other national regulations requiring quantification of leaked emissions, despite some in place providing monitoring requirements; however, the US EPA has a proposed further rule, proposed in early 2010 (US EPA, 2010) which supplements the greenhouse gas reporting rule finalised in 2009, requiring carbon storage facilities to report their emissions by calculating the sequestered CO_2 by subtracting total CO_2 emissions from CO_2 injected in the reporting year. Such does not ask for specific procedures or methodologies to be implemented, but rather asks operators to develop and implement a site-specific approach to monitoring, detecting and quantifying CO_2 leakage. Additionally, the Australian Regulatory Guiding Principles for Carbon Dioxide Capture and Geological Storage, developed with the aim of establishing a national regulatory framework state: 'Regulation should provide a framework to establish, to an appropriate level of accuracy the quantity, composition and location of gas captured, transported, injected and stored and the net abatement of emissions. This should include identification and accounting of leakage.'

Technique Uncertainties

Given the specific requirement in the EU for defining level of uncertainty in quantification estimation, it is important to consider the current knowledge on measurement instrumentation/technique uncertainties. Level of uncertainty will decrease with further refinement through increased application; however the natural system will always impose some level of uncertainty. For example, in surface water chemistry techniques, Mau et al. (2006) estimated 10 to 20% of their uncertainty was due to variations in the local background with over 50% due to current velocity variations. From reported research there is evidence to suggest some technologies in their current level of development may have uncertainty ranges exceeding the required range of ±7.5%, i.e. Trotta et al. (2010) estimated the largest uncertainties can range from 10 to 40% for different set-ups of eddy-covariance-based estimates of net ecosystem exchange; and uncertainty of CO_2 flux increases with increasing absolute magnitude of the flux (Hollinger & Richardson, 2005). Research is required to improve current understanding of sensitivities and uncertainty ranges of both individual technologies and combined monitoring portfolios.

Expert Review Comments

Expert review comments on the draft report were received from five expert reviewers. The comments provided were detailed and constructive, enabling the study contractors to respond accordingly in preparation of the final report.

General suggestions from the reviews concentrated on the focus and structure of the report, recommending re-focussing towards the original aim of quantification of leaked CO_2 emissions and, the reports consistency and clarity. Specific technical comments included noted important information with regard to the ZERT, West Pearl Queen and Frio results such as the ZERT horizontal well was drilled without disturbing the surface and not 'buried' and the leakage mechanism at the West Pearl Queen site remains unclear. Comments also complimented the contractors on producing such a useful informative document.

The final report reflects the comments of IEAGHG and the expert reviewers. The final report has been re-focussed, summarising the detailed focus on subsurface monitoring techniques in Chapter 3 in reference to detecting potential leakage pathway, and the contractors have improved the text of individual methods and the report's consistency. The contractors have provided a detailed tabulated summary of the comments and their actions to address these comments which may be made available to interested parties.

Conclusions and Recommendations

The study results highlight that for potential leaked emissions in the shallow subsurface, atmosphere and marine environment, monitoring portfolios should be focussed on identified leakage pathways, making use of deep subsurface monitoring technologies to recognise potential pathways. Alternatively it will be necessary to deploy monitoring technologies with lower resolution and wide spatial coverage to detect any CO_2 seepage before deploying more sensitive measurement techniques for quantification. To quantify CO_2 flux, no one technology has been identified, and development of an efficient monitoring portfolio will depend on the specific environment. The results show technologies suitable for quantification do exist, however these need further field testing and some proposed methods may prove unsuitable for quantification; for example ECM which though a powerful tool is expensive, complex and measurement errors and uncertainties are issues which remain to be solved. Additionally, the study highlights largest uncertainty ranges for some techniques may exceed that of current requirements, for example in surface water chemistry techniques and ECM, and it is recommended IEAGHG explore this further. For quantification purposes, further research should focus on defining sensitivities of instrumentation and uncertainty ranges, testing the technologies in a wide range of conditions for both controlled and natural releases of CO_2. Future research should also provide further insight into variability of baseline CO_2 flux which will be crucial for ascertaining suitability of techniques for specific environments; in addition to further understanding of CO_2 leakage mechanisms including conditions driving CO_2 release into the water column in a dissolved phase or as bubbles. On-going EU projects should help to build knowledge in this area. Some areas of the report are weaker than others due to data availability such as technologies in the marine environment; therefore such should be re-examined in future relevant studies. Therefore, it is recommended IEAGHG keep abreast of the latest developments in monitoring capabilities and uncertainties; with further future involvement in relevant collaborative research activities; and consider a re-evaluation of quantification techniques for CO2 leakage once further research results become available.

The study also provides a number of technology specific recommendations, provided within the final chapter of the report. These specific recommendations include a need for further testing specific to CO_2 seeps for surface water chemistry techniques in order to assess method sensitivity, precision and costs for CO_2 monitoring. There is also a need for further development of long open path lasers with more stable baseline signals and that can measure more than one pathway and, further focus on deploying short open path lasers closer the ground surface to minimise potential anomalies and testing models to monitor tracer gases that have lower sensitivity. For shallow groundwater monitoring, further research should examine integration of indirect methods such as EM to enable wider spatial coverage and, for airborne EM further work should examine the discrimination of the effects of CO_2 leakage from alternative scenarios such as seawater intrusion.

2012-09 BARRIERS TO IMPLEMENTATION OF CCS: CAPACITY CONSTRAINTS

Background To The Study

As part of its on-going work programme, the IEA Greenhouse Gas R&D Programme (IEAGHG) has undertaken a number of studies to assess potential barriers to the implementation of Carbon Capture and Storage (CCS). In the latest study in this series, IEAGHG looks to explore whether there are supply and capacity constraints associated with equipment for CCS plants that might cause issues with CCS implementation. A related earlier study by the IEA Clean Coal Centre for new build coal fired power plant identified that there are potential areas of supply constraints in key components like castings for gas turbines and basic raw materials like steel and cement for plant construction. This study aims to build upon this earlier work by looking at the CCS components for new build plant to see if there are any additional critical component issues.

The IEA Technology Roadmap for CCS has been taken as the reference case for the study because it proposes an aggressive deployment strategy for CCS up to 2050[1]. This reference case, envisaged that 100 CCS projects need to be deployed by 2020 and suggested that by 2050 alone, up to 150Gt of CO_2 will need to have been captured and stored if CCS is to make the required contribution towards constraining temperate rise at 20°C by 2050. To achieve such targets CCS will be ramping up production rapidly (at the same time as other low carbon technologies) and issues may arise regarding materials/ equipment and services supply that need to be identified early to ensure that these issues do not represent barriers to the implementation of CCS.

A contract for this study was awarded to Ecofys, B.V. of the Netherlands.

[1] The CCS Technology roadmap (IEA, 2011) builds on the IEA BLUE Map scenario in Energy Technology Perspectives 2010 (IEA, 2010), which combines the deployment of different (low carbon) technologies to achieve global CO2 emission reductions: from just below current 30 GtCO2 to 14 GtCO2 by 2050 (the baseline scenario results in 57 GtCO2). In the BLUE Map scenario CCS contribution to the emission reduction in 2050 – compared to the base line scenario - is 19 %.

Scope And Approach Taken

The study tried to be as comprehensive as possible but to limit the scale of the study some compromises had to be made. The study was based on global requirements and essentially used a high level approach and did not consider regional differences in skills, manufacturing bases etc., The study considered the full CCS chain, i.e. capture, compression, transport and storage of CO_2 but excluded the power/industry equipment prior to the capture plant. It was considered that the manufacturing constraints for the equipment preceding the capture plant were already understood. For example, components needed in coal fired power plants were covered by an earlier IEA Clean Coal Centre report[2]. As far as the capture plants were considered, the focus of the study was on current state-of-the-art technologies, including pre-combustion, post-combustion and oxyfuel combustion technologies. Second generation capture technologies (i.e. solid looping, membrane technology etc.,) were not considered in the study, because it was felt that being at an early stage of their development it would be difficult to quantify future component needs and manufacturing constraints. The sectors considered were the heavy manufacturing industry, power generation and upstream oil and gas. The upstream oil and gas sector includes fuel and gas processing and is regarded as a sector with many opportunities for low-cost capture that will arise in the future as new gas resources come on stream in regions like South East Asia that have high CO_2 contents. For CO_2 transport the study focused on transport by pipeline only. It was considered that apart from offshore CO_2-EOR operations the bulk of the CO_2 transported for emissions reduction will be by pipeline in the period of the scope of the review. Other transport mediums such as ship, truck and train were not considered for reasons that included lack of capacity (truck and train) and because the technology is not yet fully developed in the case of ships. CO_2 storage capacity assessment constraints were not included in the supply chain; this subject is covered in a separate IEAGHG report[3].

Prior to undertaking the detailed analysis the contractor first considered the scale of construction implied by the IEA CCS Road Map. The Road Map requires 100 CCS projects to be installed by 2020 capturing some 500 Mt/CO_2/yr. and 3,500 by 2050 capturing some 10,000 Mt/CO_2/yr.; an overall increase

[2] "Meeting the demand for new coal-fired power plants". IEA CCC Report No. 141. Nov 2008. ISBN 978-92-9029-460-3.
[3] IEAGHG Report No 2011-10, Global Storage Resources Gap Analysis for Policy Makers, November 2011.

of 9.5Gt/CO_2/yr. in 30 years. The consultants then compared the rollout of the technology as required by the Road Maps implementation rate to prior developments in the power, industry and oil and gas extraction sectors. The aim of this exercise was to determine whether manufacturing constraints will arise depending on, amongst other factors, the deployment rates considered in the IEA CCS Roadmap.

Supply constraints were divided into those relating to **Equipment & Materials** and those relating to **Services & Skills**. Figure 1 overleaf outlines the approach used. Figure 1 shows that the operation of power plants with CO_2 capture requires human resources and raw materials (e.g. chemicals or metals). In essence, all parts of the supply chain(s) that are necessary to plan, design, construct and operate a (part of the) CCS chain require human resources and raw materials or sub-components from other industries or from the natural environment. In each part of the chain, a constraint may occur. This can be due to scarcity of natural resources, or the limited production capacity of a component, or a shortage of specialist technical skills, e.g. welders, drilling rig operators, electrical engineers etc.

It was considered impossible to assess all components in a CCS chain (i.e. to the level of bolts and screws), so the contractors limited themselves to the main components in the CCS installations. In each case an equipment list was drawn up and from this the contractor selected components, using a screening assessment process, which is detailed in Chapter 3 of the main report. For human resources, the contractor considered job profiles that are needed for capture, transport or storage activities. Each individual component identified is then assessed in detail in Chapter 5 of the main report. Note: whilst regulatory/permitting approvals could also be considered as part of the CCS chain these were not considered as part of the scope of this study.

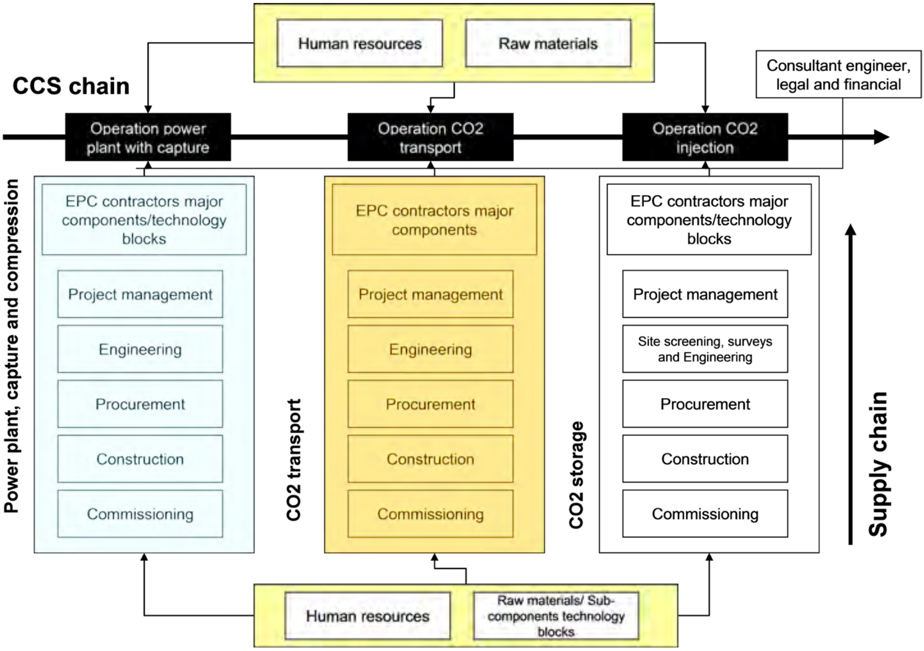


Figure 1 Graphical representation of the supply chains for CCS technologies. Horizontally the CCS chain is shown. Vertically the supply chain is shown for the three parts of the CCS chain. Note EPC refers to: Engineering, Procurement and Construction

Results and Discussion

With regard to the envisaged technology roll out suggested in the IEA CCS Road map; the following points were noted:

- The highest growth rates in coal fired power capacity in the 20th century were achieved in 1950-1960 in OECD countries. In that period, the average annual growth rate (in power capacity) was 19%. To achieve the targets in the CCS Roadmap, the annual growth in coal CCS projects must reach an average of 17 GW (15 installations) per year in the period 2020-2030, 29 GW (24 installations) per year between 2030 and 2040 and 28 GW (22 installations) per year over the period 2040-2050. To compare, the deployment rate of coal-fired power plants globally in the period

1960 to 2000 was about 130 installations (27 GW) per year. The historical construction is therefore comparable to the needed future building rate of coal-fired power plants with capture installations. Over the last five years, there was a sharp increase in the construction rate of coal-fired power plants. This induced many supply chain problems, which are set out in the main report but include. For example, in China alone, more than 100 GW was under construction in 2009 (IEA, 2009b).

- For natural gas in terms of both the number of projects and the capacity per year, the historical building rate exceeds the projected future building rate of gas-fired CCS installations in the power sector. To achieve the targets in the CCS Roadmap, the annual growth in CCS projects in NG-fired power plants must reach an average of 4 GW (12 installations) per year in the period 2020-2030, 11 GW (37 installations) per year between 2030 and 2040 and 20 GW (63 installations) per year over the period 2040-2050. In comparison, the historical deployment rate in the period, 1960-1980 was approximately 170 installations (12 GW) annually. The building rate increased sharply in the period 1980-2000 to over 500 installations (24 GW) annually. In 2002, the construction rate peaked at 1,000 installations and 72 GW. This assures us that with the engineering resources power plant build rates as required by the CCS Roadmap could be attainable in the future.

However, it must be noted that, the underlying assumptions in ETP 2010 requires high construction rates not just for coal fired power plants, but nuclear, wind and solar PV at the same time. It was felt there are no major components used in these technologies that were also needed for the CCS chain. Large-scale deployment of nuclear power and renewables might directly and indirectly compete for resources with CCS such as:

- technically skilled personnel for the construction of nuclear power plants
- drilling rigs for deep geothermal power production
- offshore cable laying vessels for offshore wind, or engineers that consider a career in wind power instead of CCS technology

In 2006, industrial emissions totalled 6.8 $GtCO_2$. The CCS Roadmap envisages 4.5 $GtCO_2$ captured annually by 2050 in the industry and upstream sector, i.e. about 65% of current industrial emissions. To achieve this, CCS in industry would need to grow 23% annually (in terms of captured emissions) between 2020 and 2030. There are no historical build rate data to compare with for industry plant. For industry it is probably optimistic to think this rate of CCS introduction can be achieved.

To gain an understanding of the magnitude of the transport and storage operations, the contractor compared the amount of captured and stored CO_2 in the CCS Roadmap with the annual production of crude oil and natural gas. After 2045, the CO_2 transport and injection capacity must be larger than the total transport and extraction capacity for oil and gas production. CCS shares part of the supply chain with the oil and gas sector; labour (e.g. experienced geo-scientists) and large facilities (e.g. ships, platforms and drilling rigs). Substantial competition between CCS industry and the oil and gas industry can be expected (especially in the field of transport and storage).

An overview of the potential of supply chain constraints for the assessed equipment and services and skills, is given in figure 2. Note: the figure is constructed around a risk element; that is the risk of a component in the CCS chain causing a capacity supply constraint. The causes of the high risk categories for individual components in the supply chain in each case are listed at the right of the diagram. The components that represent a high risk of causing a supply constraint are mainly related to storage and transport. These include: large scale pipelines (limited number of manufacturers with full order books) and availability of drilling rigs, competition from the oil and gas sector for petroleum engineers and geo-scientists and the availability of large CO_2 compressors (limited number of manufacturers with proven technology). For capture, supply chain issues are considered for pre-combustion capture namely hydrogen rich gas turbines as these are not yet commercially available or proven. Other low to medium supply risks are for catalysts, absorption towers, ASUs, and advanced flue gas treatment.

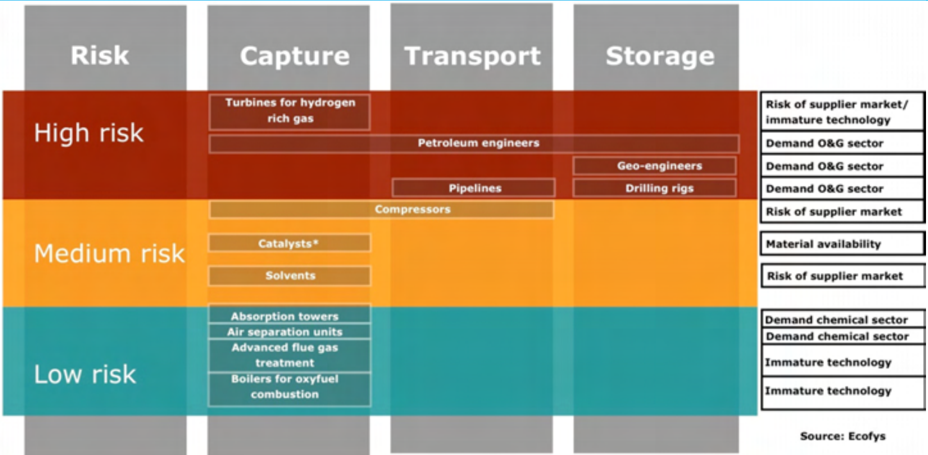


Figure 2: Potential Supply Chain Constraints

For capture, supplier concentration is the main risk

Some components, such as advanced flue gas treatment, solvents and hydrogen rich gas turbines are still under development. There is a potential risk that the 'winning' technology results in a high supplier concentration; this makes it attractive for EPC contractors to vertically integrate their supply chain. Vertical integration in the chain may result in large conglomerations/ joint ventures across the supply and value chain. One tipping point in the chain may result in constraints across the whole chain. For example, if one company offers a capture block and the preferred supplier is not able to meet demand, then the whole capture block faces longer lead times. It reduces risk for parties involved, but may create supplier dominated market conditions and result in inflexible markets.

An historical comparison showed that technological developments and knowledge diffusion can be realised within a relatively short time if sufficient demand-pull (via regulations/obligations/standards) is in place.

Differences in supply chain constraints for the various capture technologies

Based on the analysis undertaken, no firm conclusion can be drawn on which capture technology has the most significant supply chain constraints. All three capture technologies have components that may form a potential risk and may be a barrier for large scale deployment of CCS. For pre-combustion it is the gas turbine; for oxyfuel it is the; ASU, flue gas treatment and boiler;

and for post-combustion it is expected to be the large scale absorbers and perhaps 'monopolised' solvents. Based on the methodology used in this study and current data availability it is not possible to firmly conclude on what the effect of any of these supply chain bottlenecks occurring would be on the deployment and market share of the three capture technologies.

Detailed data (i.e. below the level of EPC, large technology providers) on the CCS supply chain in many cases is difficult to collect, because of three main reasons. The first is that the supply chain of the large EPC contractors entails a large number of suppliers and sub-contractors which would require a more extensive study to map them all. The second reason is that competitive reasons limit the disclosure and thus an overview of all suppliers and sub-contractors in the supply chain to the EPC contractors. The third reason is that a detailed overview of the supply chain is mostly relevant for the short term (typically <5 years). Long-term dynamics in the full supply chain are extremely difficult to assess on a detailed level.

Meeting global demand for compressors and large scale CO_2 pipelines will be challenging task

CO_2 compressors are mature for lower pressure ranges but require R&D for the high pressure ranges often necessary for offshore CO_2 transport. All CCS projects would require compressors and it therefore faces high demands. Together with competition for natural gas compressors needed in the oil and gas industry, this may lead to shortage in supply capacity.

Pipe laying capacity faces competition with the oil and gas industry and the current market for laying very large scale pipelines is small. The scale and amount of pipelines needed for CCS may temporarily fill order books of pipeline laying companies and increase prices and lead times.

Oil and gas extraction will compete severely with CCS activities

For storage exploration, skilled engineers are needed, who are now mainly working in the oil & gas sector. Between 2020 and 2030, CCS activities already require equipment and staff, not only to construct capture installations, but also to assess and explore reservoirs, drill assessment wells, assess the reservoir capacity and test with injection trials. The oil & gas sector already experiences difficulties with staffing, and because of the specific skills and experience that is needed; suitable staff can hardly be recruited from other sectors. The most critical part is the data collection on CO_2 storage reservoirs: on-site measurements, modelling and monitoring will require the knowledge of skilled geo-scientists.

Knowledge and expertise is concentrated in the oil and gas industry, not only upstream (e.g. oil drilling) but also downstream (e.g. petrochemical refining) that relates to knowledge of CO_2 capturing process being partly concentrated in the oil & gas sector.

If there is continued, and in the worst case for CCS, increased exploration and production of oil and gas; a shortage of staff and equipment might cause problems, particularly for offshore drilling. This may then result in shortages in equipment and operators and higher costs for drilling offshore CO_2 wells.

Because of their knowledge, oil companies (and their contractors) will be critical facilitators for CCS, in both exploration of reservoirs and in constructing capture installations. This means that, in times of labour shortages, oil and gas companies may have to choose between CCS and oil and gas extraction activities. As the revenues from oil activities are likely to be higher than CO_2 (currently the price of CO_2 is very low <$10/t), there is a severe risk that CCS activities will become understaffed and underequipped, i.e. the cost of equipment and staffing increase. There is of course a risk that high staff costs and rig costs might render CCS uneconomic in the future.

Expert Review Comments

Expert review comments on the draft report were received from five reviewers. The comments provided were detailed and constructive, enabling the study contractors to respond accordingly in preparation of the final report.

A recurring theme in the general comments was the subjective nature of some of the views expressed in the report. Whilst it was applauded that ranking of the importance of issues had introduced some objectivity and structure, arbitrary opinion without detailed analysis remained in many cases. In the absence of the discovery of clear showstoppers it is inevitable that the essence of the report is subjective opinion.

The point was made that the title "Capacity Constraints" could lead to confusion with CO_2 storage volumetric capacity, which was outside of the scope of the study.

Conclusions

The study has concluded that there are no insurmountable obstacles to the implementation of CCS at the rate of the IEA CCS roadmap were identified. However the scale of CCS implementation to match the IEA CCS roadmap would be large:

- In the power sector the construction rate of power plants with CCS would be lower than historical power plant construction rates;
- In the industry sector approximately 65% of current emissions would be captured by 2050 which is an optimistic target to achieve;
- In the oil and gas sector more CO_2 would be captured annually than the current volume of annual global oil and gas production.

The most significant risk to rapid CCS deployment comes from competition with oil and gas exploration activities for experienced staff and drilling equipment.

The pre-combustion and oxy-fuel capture technologies contain elements that are not mature technology. The post combustion capture technology may become constrained by availability of materials.

Shortages of technically skilled personnel are most likely to appear, particularly for job profiles that are also required for oil and gas extraction; i.e. petroleum engineers and geo-scientists.

Recommendations

The report formulates the following recommendations to mitigate the impacts of barriers to the implementation of CCS.

1. **There is a need to reduce the risks for upfront investments, particularly for reservoir exploration and CO_2 transport infrastructure.**
   For early operation of CCS installations upfront assessment and design of the transport and storage component is essential but is expensive.

2. **There is a need to mitigate competition with oil and gas extraction activities via education.**
   Students should be encouraged to view a career in CCS technologies as complimentary to a career in the oil and gas industry, requiring the same training and skill development.

3. **We need to investigate in detail the knowledge and expertise needed for storage assessment.**
   A knowledge gap is identified in the area of geological CO_2 storage assessment.

4. **Promote international data exchange.**
   Consistent and accurate estimates of storage capacity are needed in most world regions at an early stage of CCS deployment to prevent the storage component becoming a constraint.

5. **We should try and stimulate diversity of suppliers in R&D and in demonstration and pilot projects.**
   In order to avoid later constraints of a suppliers market, diversity at the RD&D stage should be encouraged.

6. **We need to encourage recycling and optimization of materials that are likely to be in short supply.**
   Recognition at an early stage of the intrinsic value of critical materials should help to reduce equipment supply constraints as CCS activities rapidly expand.

7. **We need to build up institutional knowledge.**
   Specialist knowledge will likely be pulled towards the active industries. However, technological knowledge is needed in regulatory authorities and other institutions to assist with the permitting/regulatory monitoring of CCS projects otherwise this could become a constraint on the deployment of projects.

2012-11 FINANCIAL MECHANISMS FOR LONG-TERM CO_2 STORAGE LIABILITIES

Background to the Study

Liability, both compensatory and stewardship, is the legal responsibility that one has to another or society, enforceable by civil remedy or criminal punishment. Post-closure (long-term) liability for carbon capture and storage (CCS) is largely related to potential migration (within the subsurface) or potential leakage (to the surface) of the stored carbon dioxide (CO_2). The IPCC Special Report on Carbon Dioxide Capture and Storage (2005) describes potential pathways for such leakage to take place: for example via poorly abandoned wells (the most likely), through pores of low-permeability caprocks, or migration through faults. Such leakage could result in environmental risks (groundwater contamination and risks to the ecosystem), subsurface trespass, and climate effects. Potential CO_2 leakage must also be considered in terms of emissions accounting liability where that applies. It must be recognised that the containment of CO_2 should become safer over time due to geophysical and geochemical processes that can act as trapping mechanisms for the stored CO_2. However, emissions accounting liability under an emissions trading scheme (ETS) can be accumulative and uncertain as to scope and ETS value, which can create great uncertainty for operators and authorities.

During the operational phase of a CCS project until closure (short-term) it is logical to apportion the liability to the operator of the site as they are most able to manage the risk of any leakage occurring (although there could also be a degree of risk sharing with authorities). For the post operational phase (long-term) however, it is possible that the former operator of the site will not be able to be held accountable over much longer timescales and a not-uncommon expectation is that liability will transfer to the state. A major issue on the liability of CO_2 storage is when to set the shift from 'short-term' to 'long-term'.

There are numerous current regulations and emerging CCS-specific regulations that need to be considered when investigating long-term liability mechanisms. The European Commission (EC) adopted a Directive (2009/31/EC) in 2008 to enable environmentally-safe capture and storage of

CO_2 in the European Union (EU). The Directive has been accompanied by EC Guidance Documents, which, though not legally binding, provide guidance on risk management, site characterisation, monitoring, corrective measures, transfer of responsibility, and financial security/contribution. These Guidance Documents consider different types of both compensatory and stewardship liability, with financial liability covering post-closure obligations for surrender of emission allowances under the EU ETS, monitoring, and corrective measures (in the event of leakage).. The US Environmental Protection Agency (EPA) rule on CO_2 storage (2010), requires financial support from the operator until the end of post-injection site care and monitoring (suggested as 50 years). Financial instruments allowable include trust funds, surety bonds, letter of credit, insurance, self insurance, corporate guarantee and escrow account. In the EU, allowable financial mechanisms (described in EC Guidance Document 4) include funds (or deposits), trust funds, escrows, bank guarantees, irrevocable standby letters of credit, and bonds issued by a bank. Financial mechanisms for long-term liability will be responsible to either the operator or competent authority, depending on the regulations of that specific region. Zurich Insurance have developed a number of insurance policies for CCS although currently they do not cover long-term liability. At the time of the development of the EC and EPA regulations it was viewed that there was a need for information and assessment of such financial instruments and their applicability to CCS projects.

Scope of Work

The study aimed to review current laws and emerging CCS specific regulations, in different regions of the world and under different legal frameworks, concentrating on long-term liability aspects. The primary work of the study was to investigate and assess the various potential financial mechanisms for supporting CO_2 liability, including an assessment of their applicability and practicality to all parties concerned, and provide recommendations based on the findings. As well as discussion on important issues such as when and how transfer of liability to the government should occur, and what these liabilities could be, the study focuses primarily on how this liability can be supported.

The specific objectives for this study were as follows:

- Review current CCS and non-CCS regulations in different regions of the world with a focus on financial mechanisms for long-term liability, including government assumption of liabilities.
- Investigate and assess potential financial mechanisms for long-term CCS liability and provide recommendations based on the findings. Clearly explain the strengths and weaknesses of potential financial mechanisms to address facilities' long-term CCS liability concerns.
- Assess liability transfer issues such as when and how transfer of liability to the government can occur, what these liabilities could be, and how liability transfer can be supported financially.

Short-term liability before project closure and applicable financial mechanisms may also represent an important issue for storage operators but was not within the scope of this study. It was ensured that the contractor for this study had a thorough understanding of appropriate liability, insurance, and financial mechanism sectors globally, as well as an understanding of the liabilities associated with CCS.

Findings of the Study

The financial challenge for private and public entities is to make provisions for paying in the future for stewardship responsibilities and compensatory liabilities after CO_2 injection has ceased, which is when the geosequestration facility's revenue stream may be much less. The financial challenge is complicated by the uncertainty of whether any compensation claims will arise, when they might appear, and what their magnitudes might be. Stewardship obligations have two elements that require funding – a steady low-level cost of inspection/monitoring with another element of higher costs (e.g., for remediation of leaks) triggered by physical events affecting the storage facility. Uncertainty affects the financing of both compensatory liabilities and stewardship liabilities, which may continue into perpetuity.

Of particular concern to stakeholders is the lengthy and indefinite timeframe of possible long-term stewardship and size and uncapped compensatory liability at CCS storage facilities. Stakeholders are seeking clarity about how, if at all, regulatory frameworks will incorporate financial requirements for long-term stewardship and compensatory liabilities; which financial mechanisms will regulatory frameworks allow to be used to satisfy financial requirements; and how those options will work (including cost and availability).

This study was conducted because little information of general applicability that responds to these concerns, needs, and beliefs is available to CCS stakeholders.

In general, for facilities posing potential environmental safety and health risks, financial requirements typically apply to one or more of the following liabilities:

- Proper closure/decommissioning,
- Remediation,
- Aftercare,
- Rehabilitation/reclamation of affected land for another use,
- Compensation of bodily injury and property damage/loss to private parties,
- Compensation of damage/loss to the public's natural resources.

Within the EC, the liabilities associated with CCS projects could include the following:

- Monitoring,
- Corrective measures, including measures to protect human health, in the event of leakages or significant irregularities,
- Surrender of emission allowances due to inclusion of the storage site under the ETS Directive,
- Sealing the storage site and removing the injection facilities,
- Operating the site, if the government withdraws the storage permit, if the government decides to continue CO_2 injection temporarily until a new storage permit is issued,
- Making the required financial contribution (FC) for post-transfer liabilities available to the government prior to transfer of responsibility. The EC recommends that the FC obligation be covered by a financial mechanism commencing during the operations period.

According to the US EPA, the CCS liabilities which have to be covered by the financial instruments must cover the following:

- Corrective action for plugging of abandoned wells and underground mines in the injection area ,
- Injection well plugging,
- Post injection site care and site closure,
- Emergency and remedial response.

These EPA CCS regulations do not include financial requirements for compensatory liability.

Financial Mechanisms

A financial mechanism refers to one of many instruments that can be used to ensure funding for long-term liabilities. This report identifies and describes eighteen types of financial mechanisms. The report describes the strengths and weaknesses of each type of financial mechanism, including an assessment of its applicability and practicality to all parties concerned.

The description of the mechanisms is provided below, with the summary of the analysis of each for their applicability and practicality in relation to long-term CCS obligations. More detail on the analysis of each is provided in the main report.

Third-Party Mechanisms

Irrevocable Trust Fund: Independent trustee accepts property from owner/operator to manage as a fiduciary for a particular purpose on behalf of a beneficiary (e.g., government regulatory agency). Trustee is a bank or other financial institution that is regularly examined and regulated by an independent financial oversight entity. Once accepted into the trust fund, the property ceases to be owned by the owner/operator, is outside its control and beyond the claims of its creditors. The trust is considered irrevocable because the owner/operator cannot unilaterally terminate the trust and reclaim the property.

Applicability: Trust funds are well suited to provide financial security over the long-term as they are “irrevocable” and protected from claims of creditors.

Practicality: Trust funds are practical for CCS long-term liability because they have low administrative burdens and are available to all operators, regardless of credit-worthiness.

Escrow Account: Agent of the owner/operator manages funds set aside for an explicit purpose. Unlike the trustee for an irrevocable trust fund, the escrow agent does not owe the government beneficiary a fiduciary duty. Instead, the escrow agent is responsible to the party placing funds into the escrow. Funds in escrow remain the property of the owner/operator, and are subject to the control of the owner/operator and the claims of creditors. .

Applicability: Escrow accounts offer less security compared to other mechanisms due to their revocability and lack of protection from claims of creditors of the owner/operator.

Practicality: Escrow accounts have not traditionally been used to finance long-term obligations and so may not be practical given limited experience.

Bank Demand (Payment) Guarantee, Irrevocable Standby Letter of Credit, Surety Bond (Payment Bond): All three of these mechanisms involve a third party (i.e., bank or surety company) guarantee of payment, up to a specified limit, to the beneficiary (e.g., government) on demand if specified conditions are met. The owner/operator is responsible to reimburse the third-party guarantor. Issuers must be financial institutions that are regularly examined and regulated by an independent financial oversight entity.

Applicability: Well-suited to provide assurance over long time-periods because they can be "irrevocable", automatically renewed, and the amount is easily adjusted.

Practicality: Able to secure high amounts. Financial institutions generally do not expect to incur significant risks from these mechanisms and offer them only to creditworthy parties.

Surety Bond (Performance Bond): Surety company guarantee that it will satisfy the owner/operators obligations as specified in the surety agreement, if the storage site owner/operator fails to perform. Unlike a surety payment bond, the performance bond gives the surety the option to perform the owner/operators' obligations.

Applicability: Well-suited to provide assurance for obligations that can be performed such as stewardship.

Practicality: They are "irrevocable" and automatically renewed. Financial institutions generally do not expect to incur significant risks from these mechanisms and offer them only to creditworthy parties

Prepaid Insurance Policy for Assurance of Closure & Post-closure Monitoring: Insurer guarantees costs of performing closure and post-closure monitoring upon the insured's prepayment of the required premiums. Issuers must be financial institutions that are regularly examined and regulated by an independent financial oversight entity.

Applicability: A prepaid insurance policy can be used for closure and post-closure monitoring, is nearly irrevocable, and places the secured funds beyond the control of the CCS operator, making it an applicable mechanism for long-term CCS liability.

Practicality: The limited availability of prepaid insurance policies to cover CCS closure and post-closure liabilities may make this an impractical mechanism at the current time

Liability Insurance Policy for Payments Due to Losses or Damages: Insurer guarantees payment for losses or damages incurred by others. Scope of liability insurance typically addresses damages or losses to parties other than the owner/operator, including losses/damage to publicly-owned resources. Terms, conditions, definitions, and the like may restrict coverage to defined amounts, perils (causes), losses, parties, and the like, which may result in insurance that does not fully address financial requirements. Issuers must be financial institutions that are regularly examined and regulated by an independent financial oversight entity. These policies are not irrevocable.

Applicability: Liability insurance might not be available in the marketplace to provide for payments, due to losses or damages incurred by other parties. Liability insurance does not provide financial coverage for long-term stewardship and other first-party liabilities such as corrective measures.

Practicality: The limited availability of liability insurance products for CCS long-term liability makes insurance not a practical mechanism for CCS at this time.

Corporate Guarantee from Non-affiliated Corporation Based on (Annual) Financial Test: A company neither owned by nor having a common owner with the storage facility owner/operator guarantees the owner/operators' obligations. The financial test must be met by the non-affiliated corporate guarantor and may include requirements for net working capital, total assets, tangible net worth, and/or credit ratings.

Applicability: Generators of CO_2 that are not affiliated with the operator can provide guarantees if they can pass the financial test.

Practicality: Corporate guarantees from non-affiliated companies are low cost financial mechanisms for CCS long-term liability.

Third-Party Administered Mutual Industry Pool: Third-party (neither the government nor an owner/operator) manages collective fund into which multiple industry members contribute. The fund is available to pay for long-term stewardship and/or compensation either as a primary funding source or as a back-up if contributors fail to meet their obligations. As a collective fund, industry members do not have individual accounts that limit payments from the fund to the sum of an individual's contributions plus interest. The fund could be organized as a mutual insurer, a group captive, a risk retention group (in the United States), or otherwise.

Applicability: Pools require a number of relatively homogeneous members facing independent financial risks. If CCS operators are not likely to be active and viable during the period after closure in which long-term liabilities could arise, mutual industry pools might not have enough resources to properly address financial requirements, and thus are a poor financial mechanism to assure long-term liabilities associated with CCS.

Practicality: Until there are enough active CCS operators, mutual industry pools will not be a practical option to adequately address long-term financial requirements.

First-Party Mechanisms

Security Interests in Property: Creation of a claim on owner/operator assets to guarantee the performance or payment of an obligation. The government beneficiary of the security interest has preferential rights, usually the right to seize and sell the property in the event that obligations are not met. The ownership and control of the property remains with the owner/operator and is subject to the claims of other creditors.

Applicability: Security interest in property would not be applicable for recurring stewardship liabilities.

Practicality: Security interests in property would be a high-burden, high-risk, inflexible mechanism for long-term CCS liabilities.

Charge over an Operator's Bank Account: Creation of a claim on an owner/operator bank account to guarantee the performance of an obligation. The government beneficiary of the charge has preferential rights, usually the right to access funds within the bank account in the event that obligations are not met. The ownership and control of the bank account remains with the owner/operator and is subject to the claims of other creditors.

Applicability: A charge over a bank account can last only as long as the account, so this mechanism would not be able to outlast the operator. In the event that liabilities arise after the CCS operator has gone out of business, the government would need to use public money to take on those obligations.

Practicality: Industry could easily establish and maintain this mechanism at low added cost, given existing bank accounts. High burden on the government to continuously oversee the charge makes this mechanism impractical

Corporate Guarantee from Affiliated Company Based on (Annual) Financial Test: A company affiliated (as parent, subsidiary, or having a common parent) with the site owner/operator guarantees the owner/operators' obligations. In this case, the financial test must be met by the affiliated guarantor. A guarantee from a subsidiary of the owner/operator does not provide an independent source of funding because the subsidiary's financial strength is subject to demands from its parent company.

Applicability: Like CCS operators, affiliated companies that make corporate guarantees are at risk of not remaining active and viable for the duration of the longer-term liabilities. Corporate guarantees set aside no actual funds and may not offer a fully independent source of funds due to intercorporate affiliations.

Practicality: Corporate guarantees from affiliated companies based on financial tests could provide low-cost, financial mechanisms for long-term CCS liability. Affiliated companies may be financially strong and relatively independent of the financial condition of the operator.

Self-Guarantee Based on Annual Financial Test: Owner/operator demonstrates ability to pay for obligations using a financial test, which may include requirements for net working capital, total assets, tangible net worth, and/or credit ratings. Not an independent source of funding.

Applicability: Self-guarantee provides no additional financial resources beyond what the operator can raise. CCS operators unlikely to be both active and viable for the potential duration of their long-term liabilities.

Practicality: Government regulators may not have skills and interests required to assess whether the operator's finances pass the financial test.

Self-Guarantee with Internal Account Reserve (Instead of Financial Test): Owner/operator guarantees satisfaction of obligations by designating an internal account for that purpose. The ownership and control of the funds remains with the owner/operator and is subject to the claims of creditors. Not an independent source of funding.

Applicability: Because CCS operators are unlikely to remain active and viable during the period after closure in which long-term liabilities could arise, internal account reserves provide very little financial security for long-term liabilities.

Practicality: Internal account reserves provide a financial mechanism with low cost for a CCS operator to establish and maintain.

<u>*Government Mechanisms*</u>

Deposits of Cash or Cash Equivalents to Government Authority (GA): The government agency accepts cash or cash equivalent deposits directly from owner/operator to be used later to satisfy owner/operator obligations. GA may create a special account on behalf of the owner/operator or may turn the funds over to the government treasury.

Applicability: A deposit to a GA can last as long as necessary, which makes this mechanism well suited for long-term CCS liabilities.

Practicality: A deposit to a GA may not be a practical mechanism for operators without sufficient assets or cash flow. The GA in some countries may not have an established record of long-term continuity.

Government-Administered Pooled Funds: Government manages pooled fund. Contributions may be received directly from owners/operators or indirectly as fees on injection, electricity use, or fossil fuels purchased for power generation. The fund can be designed either as a primary funding source or as a back-up available to reimburse the government if an owner/operator fails to meet certain obligations and the government becomes responsible to satisfy owner/operator obligations.

Applicability: Government-administered pooled funds can assure coverage for long-term CCS activities, with a sufficient number of financially viable participants and if the funds are protected from being appropriated for other uses. Urgent, non-CCS-related scenarios may arise that result in diversion of funds.

Practicality: Government-administered pooled funds are difficult to set up and maintain. Risk-based fees likely to be more controversial than per unit fees.

Government Guarantees: Government agrees to guarantee payments to claimants for specified liabilities as a back-up. A guarantee is a promise to answer for the debt, default, or other liability of another. A government guarantee about CCS could mean that the government will pay for third-party damage/loss that the responsible owner/operator fails to pay. The payment goes not to the owner/operator (as for indemnification) but from the government to the party that the owner/operator has not paid. Because the government issues it, the guarantee can outlive the owner/operator.

Applicability: Government guarantees are considered secure and likely to last longer than mechanisms provided by private-parties.

Practicality: Government guarantees are commonly used in jurisdictions to foster infrastructure development and industrial activity. This mechanism could be used in countries where the government and its finances are stable enough to guarantee payments over the long timeframe of post-closure CCS activities.

Government Assumptions of Liability: Government takes primary responsibility away from the site owner/operator for specified liabilities if pre-determined criteria have been met. Also referred to as "transfer of liabilities."

Applicability: Governments are considered more likely to be active and viable in the long-term than industry. The government could require that an operator fulfill certain safety requirements prior to the govenrment's assumption of liabilities to minimize the risks and magnitudes of long-term liabilities assumed by the government.

Practicality: Government assumption of liability would be an attractive option for operators who may be wary of entering the CCS industry due to the indefinite time-frame and uncertainties of long-term CCS liabilities. The implementation of government indemnities could involve many government departments and legislation, resulting in a high administrative burden. The public and government may be unlikely to be willing to take on liabilities in uncapped amounts.

Government Indemnities: Government agrees to reimburse owner/operator for payments made for specified liabilities. Not a primary funding source. The indemnification payment goes to the owner/operator from the government, unlike for government guarantees where the payment from the government goes to the creditor of the owner/operator. Because indemnification is a duty owed to the owner/operator, that duty ceases if the owner/operator is defunct.

Applicability: Governments are considered more likely to be active and viable in the long-term than industry. The government could require that an operator fulfill certain safety requirements prior to the governments' assumption of liabilities to minimize the risks and magnitudes of long-term liabilities assumed by the government.

Practicality: Government indemnities would be an attractive option for operators who may be wary of entering the CCS industry due to the indefinite time-frame and uncertainties of long-term CCS liabilities. The implementation of government indemnities could involve many government departments and legislation, resulting in a high administrative burden. The public and government may be unlikely to be willing to indemnify liabilities in uncapped amounts.

Approaches for transfer of long-term liability

The report identifies and analyses key generic aspects of frameworks for transfer of long-term CCS liability to the government. These aspects are: threshold technical requirements; financial requirements related to liability transfer; post-transfer cost recovery provisions; specification of which and whose liabilities may or must be transferred. For the purposes of summarising the assessments of options of liability transfer frameworks, the following comments are made on the evaluative criteria.

Costs to Industry and Government/Taxpayer Transfer of liability frameworks serve to re-allocate costs of long-term CCS liabilities away from industry and onto government. Part of the rationale for such transfers is that government bodies are more likely than businesses to endure over long time periods. In addition, there may be a net cost savings to society by having government take primary long-term responsibility for CO_2 storage sites, given that the alternative is for industry to have primary responsibility with government exercising oversight.

Incentive Effects. Much of the necessary expertise for large-scale underground CO_2 storage is found in industry. Transfer of liability frameworks are intended to make industry more comfortable with playing a large role in CO_2 geosequestration. Thus, options for liability transfer frameworks have been assessed in terms of their implications for industry participation in CO_2 geosequestration. In addition, the provisions of liability transfer frameworks might affect industry incentives for performing siting, injection, closure, monitoring, and the like, given that liability transfer frameworks are thought to create moral hazard: by transferring long-term liability to government, industry may not perform at the same level that would occur if industry retained subsequent liabilities. It is thought that requiring an owner/operator to retain some long-term liabilities reinforces incentives for proper injection and storage of CO_2 prior to facility transfer. Industry risk-sharing with government may reduce concerns about moral hazard because it creates a disincentive for the owner/operator to perform its technical responsibilities poorly.

Effectiveness of Protection of the Public/Environment. Requiring that facilities achieve high performance standards as a precondition of liability transfer should help reduce future threats to the public and the environment as well as reduce the need for future mitigation or remediation costs to be borne by industry or government. In addition to clear, objective standards (e.g., for closure) that can be assessed and verified prior to transfer of liability, an explicit post-closure monitoring period prior to transfer can assure that the responsible owner/operator has properly closed the site and that it is not leaking CO_2 either to the atmosphere or to underground formations where proper controls may be lacking.

Duration. Liabilities associated with CO_2 storage may persist for hundreds of years, possibly outlasting lifetimes of businesses. This extended duration must be considered in designing a liability transfer framework in order to ensure liability remains with an entity capable of fulfilling long-term liabilities.

Framework Aspect	Example Option A	Example Option B
Technical Requirements	Stringent conditions including a post-closure period and performance standard prior to transfer	Stringent conditions including a post-closure period and performance standard prior to transfer
Which Liabilities are Transferred	Some liabilities transferred	All liabilities transferred
Whose Liabilities are Transferred	Owner/Operator	All potentially liable parties
Financial Requirement	Per unit injection fee paid into a fund during operations	Contribution prior to transfer
Cost Recovery Provisions	Post-transfer cost recovery provisions	No post-transfer cost recovery provisions

Two Examples of Liability Transfer Frameworks

The report does not seek to recommend any one liability transfer framework option, as this is up to the host country and their national interest and policy situation. However the report does conclude by providing two examples of frameworks which, whilst 'middle of the road', show different balances between the evaluation criteria above, and in particular in balancing the assignment of costs between government and industry, incentives to industry, and providing environmental protection. These examples are shown in the table above.

Expert Review Comments

Expert comments were received from 5 reviewers, representing industry (corporate sponsors of IEAGHG) and academia. The feedback was constructive and supportive of the work that had been carried out, noting the material was overall comprehensive and detailed.

Following the expert review process, improvement to the report was made primarily in particular areas. The scope was extended to explain more what should be covered when considering liabilities and what such liabilities may be (using examples). More conclusion/summary paragraphs were added throughout the paper, in particular after lengthy tables of information, making the report easier to read and understand key points. The contractor also added some additional key references, as recommended by the reviewers, to back key ideas and improve accountability.

Conclusions

Government financial requirements primarily protect the government/ taxpayer from the risk of the operator's failing to fulfil its obligations, although some acceptable financial mechanisms also may serve as a funding source for the operator. On the other hand, for the benefit of shareholders/owners, an operator may propose a variety of positions regarding its exposure to long-term CCS liabilities, ranging from use of a financial mechanism to self-insurance without a financial mechanism (subject to agreement by the relevant authorities).

This report identifies and describes eighteen types of financial mechanisms.. The report describes the strengths and weaknesses of each type of financial mechanism, including an impartial assessment of its applicability and practicality to all parties concerned in relation to long-term CCS obligations. In most cases, industry will finding that self-guarantees and corporate guarantees present the lowest after-tax costs, if these mechanisms are acceptable in the jurisdiction and if the operator or guarantor can pass the associated financial tests of eligibility.

In developing regulatory frameworks for CCS, legislators and regulators should indicate which financial mechanisms will be acceptable for long-term CO_2 storage liabilities. Governments should allow use of multiple, acceptable financial mechanisms in order to provide compliance options to facility operators. Industry's position on financial mechanisms for long-term CCS liabilities may differ when responding to government financial requirements as opposed to when managing those liabilities independently of government financial requirements. Industry may want to propose a package of acceptable financial mechanisms that might involve more than one financial mechanism for a given long-term liability. For example, a "sinking fund" approach involves two mechanisms: (1) a fund that is built up over a given time interval (e.g., 5 years) and (2) a complementary guarantee that decreases in amount as the sinking fund increases. The two mechanisms must together equal or exceed the required amount for covering the obligation. Similarly, when an operator faces financial requirements for two or more long-term liabilities, a package of different types of acceptable financial mechanisms may allow for lower costs and a greater degree of risk-sharing with the government. For example, a package might contain a more conservative financial mechanism for post-closure monitoring combined with a potentially higher risk financial mechanism for post-closure remediation, on the theory that the remediation obligation is more unlikely to arise.

Recommendations

This report provides in one document a review of likely financial mechanisms for long-term liabilities relating to CO_2 geological storage. The report does not seek to recommend any one financial instrument or liability transfer framework option, as this is up to the host country and their national interest and policy situation. Although stakeholders may disagree about what ought to be done, this study should assist stakeholders to agree on what can be done, recognising that different approaches may be preferred in different countries and regions.

Discussion will continue to arise around long-term liabilities within the meetings of the IEAGHG storage networks, and the findings of this study should provide some more understanding of what can be done to manage and finance these.

2012-12 EXTRACTION OF FORMATION WATER FROM CO_2 STORAGE

Background to the Study

Deep saline formations (DSF) constitute the largest potential global resource for the geological storage of CO_2 and are therefore crucial to the successful up-scaling of storage from pilot and demonstration projects to commercial operations. However, there are uncertainties relating to the capacity and injectivity of DSF, with particular concerns relating to the management of pressure and potential displacement of formation brines. Extraction of saline waters from storage formations provides a potential solution to pressure management; for example the proposed Gorgon storage project in Australia includes the provision of pressure relief boreholes.

The effect of pressurisation in a storage formation will depend largely on whether the system can be considered as open or closed. In a closed or semi-closed system, the pressure build-up will be determined by the boundary conditions, which include the shale permeability. Recent studies have shown that microdarcy scale shale permeability will allow brine displacement, while very low shale permeabilities on the nanodarcy to subnanodarcy scale will not. Part of the problem comes from the uncertainty in assessing brine displacement due to boundary condition uncertainty. It can be difficult to determine macroscopic scale permeability, even when samples have been obtained, due to problems with up scaling measurements as regional permeability effects also need to be taken into account (IEAGHG, 2010).

Pressure relief wells can compensate for increases in pressure caused by injection, though extraction rates will depend on site-specific factors e.g. geological structure, shale permeability and heterogeneity.

Heterogeneities in the storage formation may cause complexities in predicting flow rate and direction of injected CO_2. If an extraction well is placed along a path of high permeability, then the rate of flow towards the well would be high, resulting in unwanted CO_2 breakthrough. This may necessitate the plugging of the old well and the consequent drilling of a new pressure relief well, thereby increasing the potential cost of the project and possibly affecting the storage security. This possibility highlights the importance of a detailed site characterisation. Brine extraction could also play a part in plume management.

The plume may be managed both laterally and vertically, as the CO_2 will be forced to migrate towards the extraction wells. In the case of forced downward migration, the extraction wells will be towards the base of the storage formation. This will cause a larger vertical proportion of the formation to be used and the lateral extent and contact of the CO_2 plume with the caprock will be reduced. Both of these effects can increase storage security. This also means that CO_2 plumes formed at adjacent or nearby injection wells would be less likely to interact with each other.

For large scale projects, there are likely to be multiple injection and pressure-relief wells. It is important to consider how they will interact with each other, as there will be an overlap of pressure footprints from each well.

The water extracted from the storage formations will need to be used or disposed of in some way, for example, at the proposed Gorgon project in Australia, the planned injection of the extracted brine will be into an overlying saline aquifer. Possibilities for future sites include disposal directly in the sea, which would be dependent on the composition of the brine; alternatively the water could be utilised for other industrial processes, such as the cooling process within power stations or use as geothermal energy or it could be desalinated and used either for irrigation or drinking water. The latter options would depend on the cost and demand of water as a resource.

The Energy & Environmental Research Center, in North Dakota, USA, was commissioned by IEAGHG to provide a thorough review of existing information and published research on the effects of brine extraction from CO_2 storage sites. The study also aims to highlight the current state of knowledge and / or gaps and recommend further research priorities on these topics.

Scope of Work

The main aim of the study would be to assess the global potential for extraction of formation waters as part of DSF storage projects. The study would comprise a comprehensive literature review, from published research and industrial analogues (e.g. brine disposal from petroleum and coal bed methane industries) to provide guidance on the following issues:

- Potential rates of brine extraction required for varying injection rates, across a typical range of DSF storage scenarios;
- Likely range in chemical composition of extracted brines;
- Options for disposal of brine, either surface or subsurface, and associated potential environmental impacts;
- Onshore and offshore considerations, including treatment required for different disposal options.
- Potential for utilisation of extracted brines, e.g. cooling water for power stations, geothermal energy, and assessment of associated environmental impacts;
- Potential for surface dissolution of CO_2 in extracted brine and re-injection into storage formations;
- Regulatory constraints, including for monitoring requirements, potential liability and water quality requirements for different uses.
- Potential economic implications for CO_2 storage of brine extraction and the various options for disposal/utilisation, to be illustrated by selected case studies.

The contractor was asked to refer to the following recent IEAGHG reports relevant to this study, to avoid obvious duplication of effort and to ensure that the reports issued by the programme provide a reasonably coherent output:

- Brine Displacement and Pressurisation (2010/15)
- Injection Strategies for CO_2 Storage Sites (2010/04)
- Impacts on Groundwater Resources (2011/11)

Findings of the Study

There is extensive industry experience in underground injection for EOR, gas storage and waste water injection, though only a limited amount in is DSF and the properties of the formations are not always detailed. Realistic and quantitative information about relevant characteristics of the subsurface is needed to assess feasibility, costs and risks associated with various options for water extraction in conjunction with CO_2 storage.

The approach taken in this report was to consider case studies with a wide range of geological, geographical and geopolitical conditions, which may impact the ability to implement an extracted water plan in conjunction with commercial scale storage projects. Relatively simple 3D models were formed to test different injection and extraction scenarios and incorporate vital, heterogeneous reservoir properties, including structure, porosity, permeability, water quality, lithology, temperature, and pressure, which were obtained from published sources. When published data were insufficient to capture expected heterogeneity or did not appear in the literature, variogram ranges and property values were obtained from the revised AGD (Average Global database), which is comprised of information from hydrocarbon reservoir properties as a proxy for DSF characteristics. The AGD was compiled through use of existing US databases and an extensive literature review for other regions (IEAGHG, 2009).

Literature considering water disposal and usage was reviewed as well as those looking at likely salinity ranges. Direct water use options include geothermal energy recovery, for which there is no limits on TDS (total dissolved solids) or water chemistry, though there are practical limits based on scaling and corrosion potential. Another option is dissolution of CO_2 into the water and reinjection; this is discussed for the individual case studies. The water can also be treated and used as a beneficial supply of water; such as drinking water, agriculture, cooling water, boiler water and other industrial uses. If this is the case, it will need to be treated, which usually requires a pre-treatment option, to remove suspended solids, dissolved gases and non-aqueous- phase fluids, such as hydrocarbons, followed by desalination. The process used will depend on the salinity, content and quantity of water. These processes are detailed in the appendices of the report. The water quality needs to be relatively high to be used beneficially and these requirements are also detailed in the appendices. The salinity and end use will determine the best desalination technology for each case.

The case studies selected were Ketzin, (near Potsdam in Germany); Zama (Alberta, Canada); Gorgon (Barrow Island, Australia) and Teapot Dome (Wyoming, USA). These projects were selected to include a range of geological conditions and formation water quality.

For each case study a range of injection scenarios were considered as well as CO_2 surface dissolution, whereby CO_2 could be stored by dissolving it in extracted formation water and then injected into a geological formation.

The economic potential of the formation water from each case study site was evaluated with respect to its applicability for beneficial use. Cost estimates were provided for desalination due to a focus on beneficial use of the water. Other water treatment and disposal options were also outlined. The range of water quality represented by the four case studies is representative of a broad range of water quality that is likely to be found in deep saline formations. The type of purification process that can be applied depends on the quality of the formation water, which is taken into account for each case study.

Some of the case study sites are located in depleted oil or gas fields and, as such, are likely to contain varying concentrations of hydrocarbons, which may increase overall treatment costs and/or limit the potential for beneficial use. These sites function as analogues for similar and less well-characterised saline formations and therefore the presence of hydrocarbon constituents in extracted water were acknowledged, but ignored for the purpose of calculations.

Ketzin

This is a pilot scale CO_2 injection project into a deep saline formation in Germany and so far 59,000 tonnes have been injected into the Triassic Stuttgart Formation. This storage formation consists of a series of fluvial channels surrounded by floodplain deposits. The confining structure is the Ketzin-Roskow anticline. The formation water quality is the lowest of all the case studies and local demand is low due to the location of the Havel River.

This theoretical case study does not reflect actual injection operations as the site is limited to a maximum injection of <100,000 tonnes, whereas the simulation uses an injection programme maximising injectivity and storage capacity aiming to inject 2Mt/yr for a 25 year period for each injection well. 16 cases (Table 1) were simulated to analyse different injection and extraction scenarios and assess differences in storage capacity and efficiency, as well as to define potential volumes of produced water for treatment or disposal.

Scenario	Well Configuration	Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m^3/day	Boundary Conditions	Storage Capacity, megatonnes
Case 1	1 Injector	451,000	*	Closed	4.12
Case 2 (base case)	1 Injector	1,430,000	*	Semiclosed	13.0
Case 3	1 Injector	1,980,000	*	Open	18.1
Case 4	1 Injector 1 Extractor	2,810,000	11,800,000	Semiclosed	25.7
Case 5	1 Injector 1 Extractor	3,000,000	12,500,000	Open	27.4
Case 6	2 Injectors	3,550,000	*	Semiclosed	32.4
Case 7 (surface dissolution)	1 Injector 1 Extractor	*	3,060	Semiclosed	0.43
Case 8 (surface dissolution)	1 Injector 1 Extractor	*	3,090	Semiclosed	0.55
Case 9 (surface dissolution)	4 Injectors 5 Extractors	*	25,500	Semiclosed	2.61
Case 10 (surface dissolution)	4 Injectors 5 Extractors	*	26,500	Semiclosed	2.88
Case 11	4 Injectors	6,954,760	*	Semiclosed	63.3
Case 12	4 Injectors 4 Extractors	7,170,000	12,700	Semiclosed	65.4
Case 13	8 Injectors	9,500,000	*	Semiclosed	86.7
Case 14	12 Injectors	14,500,000	*	Semiclosed	132.0
Case 15	12 Injectors 13 Extractors	24,877,000	65,753	Semiclosed	226.7
Case 16	25 Injectors	20,100,000	*	Semiclosed	183.8

Table 1: Case Scenarios and Resulting Storage Capacities for Ketzin

Due to the structure, geological heterogeneity, and depositional environment at Ketzin, the modelling showed that it was difficult to obtain good connectivity between injector and producer pairs, resulting in poor improvements in plume control and storage capacity. This was evident by a higher storage capacity being obtained from two injectors rather than any scenario with an injector and producer. Simulations of increasing injectors and injector/ extractor pairs show that upon reaching 25 injectors; a greater capacity is achieved through 12 injectors and 13 extractors. The reason for this is the pressure interference between injectors, which can be mitigated by extractor wells.

Surface dissolution was considered (cases 7 – 10), but due to high salinity of the formation water, large quantities of water would be required for CO_2 dissolution, leading to an extremely reduced storage capacity. Additional wells patterns were analysed to obtain an idea of how many wells would be needed to achieve 1Mt/yr. When considering 9 well patterns (4 injectors, 5 extractors) at 5 km intervals, 80-90 wells would be needed to store 1Mt/yr, which would be prohibited by cost.

The formation water at Ketzin is high-salinity, with more than 200,000 ppm TDS (total dissolved solids) and not favourable for use as source water for beneficial use. The options that have been identified for handling this water include reinjection into a geological formation or treatment with a zero liquid discharge (ZLD) method that results in a dry salt for disposal or beneficial use. Based on the flow rate of 12,400m^3/day (case 4 and 5) the water treatment was estimated to be \$8.02/m^3 with the total capital cost of \$135 million. It is unlikely that this high price for treatment and/or purification of water would be accepted or viable, therefore, deep-water injection would be the most likely management strategy for extracted water. As the Stuttgart Formation is regionally extensive and generally underpressured, it is the most likely disposal target for the site.

Regarding regulations, it has been shown over the last few years that CCS faces obstacles in Germany. However, there are regulatory frameworks in place that allow brine injection to occur as part of other industrial activities. Therefore if CCS is able to take place, brine extraction and reinjection is not likely to be an issue.

Zama

This is a hydrocarbon bearing structure that has been the site of acid gas injection for the simultaneous purpose of EOR, H_2S disposal and CO_2 storage in north western Alberta, Canada. It is a carbonate pinnacle reef structure consisting of dolomite and surrounded and overlain by a very tight anhydrite (Muskeg Formation) that acts as a caprock. The pinnacle modelled is one of 700 similar hydrocarbon bearing structures in the Zama oil field. The formation water quality is low and there are other existing local water resources, though there is the possibility of using extracted water for oil and gas production activities.

7 different cases of simultaneous acid gas injection and formation water extraction (Table 2) were tested in predictive simulation runs.

Scenario	Well Configuration	Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m^3/day	Boundary Conditions	Storage Capacity, megatonnes
Case 1	1 Injector	310,680	N/A	Closed	0.05
Case 2	1 Injector 1 Extractor	310,680	516	Closed	0.47
Case 3	1 Injector 1 Extractor	310,680	516	Closed	0.62
Case 4	1 Injector 1 Extractor	310,680	429	Closed	0.68
Case 5	1 Injector 1 Extractor	310,680	397	Closed	0.69
Case 6	1 Injector 1 Extractor	621,359	1144	Closed	0.49
Case 7	1 Injector 2 Extractors	621,359	572	Closed	0.60

Table 2: Case Scenarios and Resulting Storage Capacities for the Zama

In the base case (case 1), acid gas was injected without the extraction of formation water. Simulation results indicate that a total of 50 Mt of acid gas could be injected before reservoir pressure reaches the maximum allowable pressure limit of 22,753 kPa. Case 4 appears to be the optimum scenario. In this case, an average volumetric ratio of nearly 1:1 between extracted water and injected gas was observed while injecting acid gas at a constant rate (0.113 Mt/year) for more than 5.5 years into a closed system. It also resulted in 13 times higher storage capacity compared to base case. With over 700 pinnacle reef structures in the Zama sub basin, a careful selection of eight pinnacle structures similar to the ones modelled may provide almost 0.91 Mt a year of storage capacity and a steady stream of extracted, low quality water. Three options for water disposal investigated were, deep well injection into the overlying Slave Point Formation, treatment of extracted water using a multiple-step membrane desalination approach such as one involving nanofiltration followed by reverse osmosis treatment and lastly using extracted water as a source of geothermal energy.

The TDS of the waters range from 180,000 to 223,000 mg/L, with the lower value taken as the basis for evaluating treatment options. The flow rates used from the simulations were minimum, 3734 m3/day and maximum, 5261 m^3/day. The capital costs for treating associated with the case studies at Zama ranged from \$5.25 million to \$60 million and the energy requirements 3.7 MW to 15.7 MW. It was therefore considered highly unlikely that treatment of the extracted water at Zama would be considered as a viable option. There is limited local population and it is a remote location, so no effort was made to identify water demands for Zama. The most likely management option is disposal into the overlying Slave Point Formation, a practice that is currently being carried out by oil and gas operators in the area.

Alberta currently has regulations dealing with brine extraction and injection related to the oil and gas industry and no issues were identified that would preclude injection of formation brines into the subsurface

Gorgon

This is a planned future project for injection into a deep saline formation on Barrow Island off the west coast of Australia. The aim is to inject approximately 3.8 million tonnes a year through 8 injection wells with 4 production wells towards the west. Injection will be into the Dupuy Formation, a turbidite sequence at a depth of 2000m; the confining structure is a north–south trending double-plunging anticline. The formation water quality is of treatable quality, though there is low local demand.

Seven cases were simulated for the Gorgon test site using the planned eight injection wells and four extraction wells (Table 3).

Scenario	Well Configuration	Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m^3/day	Injection Period, yrs	Storage Capacity, megatonnes
Case 1	8 Injectors	10,661,700	*	25	97.3
Case 2	8 Injectors 4 Extractors	10,661,700	215,120,000	25	97.5
Case 3	8 Injectors	10,661,700	*	50	195
Case 4	8 Injectors 4 Extractors	10,661,700	334,919,000	50	196
Case 5	8 Injectors 4 Extractors	5,330,830	396,606,000	50	97.5
Case 6	8 Injectors	60,400,000	*	25	551
Case 7	8 Injectors 4 Extractors	69,900,000	261,802,000	25	637

Table 3: Case Scenarios and Resulting Storage Capacities for Gorgon

Based on the simulation results, water extraction at the Gorgon site appears to be most beneficial for pressure maintenance and plume control. Utilisation of the planned extraction wells achieved significant pressure reductions. Early breakthrough remains an issue and could require injectors to be shut in and more wells brought online. Capacity gains through water extraction are possible at the Gorgon site, although the amount of injection required to make those gains far exceeds the injection planned for the site.

Water handling scenarios considered for Gorgon were reinjection of extracted water into a geological formation (for pressure management in the natural gas field), ocean discharge, use as source water for reverse osmosis systems installed on Barrow island (ultimately for water supply on Barrow Island) and use as supply of water for mainland Australia communities.

Reinjection is considered to be the most likely scenario, though ocean discharge would be a low cost alternative, as the salinity is similar to seawater, TDS of 23,234 mg/L, as long as there are no hydrocarbons or radioactive material. The only other issue is the potential environmental impact of high temperature water, though it may be possible to cool it first if there is an issue. Water treatment is a high cost option, but may be an alternative to desalination of seawater, which is currently planned. The main cost is transportation, which becomes much greater when considering supplying the mainland.

If properly planned and implemented, use of extracted water could be considered as a source of feedwater for reverse osmosis production of purified water for operations at the Barrow Island site. Minimal transportation and infrastructure are required beyond current seawater desalinisation operations.

The current regulatory frameworks considered do not provide any serious constraints to brine disposal in Western Australia.

Teapot Dome

This is a demonstration site in Wyoming, situated next to a CO_2-EOR site (salt Creek). It is a stacked sedimentary sequence in an elongated anticline. The formation water is of high quality and could have many uses as there are close by populated areas and agriculture; there may also be potential for geothermal production.

The Dakota/Lakota Formation was the primary target at Teapot Dome, which was examined through seven dynamic simulations (Table 4).

Scenario	Well Configuration	Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m^3/day	Storage Capacity, megatonnes
Case 1	1 Injector	565,128	*	5.2
Case 2	2 Injectors	836,848	*	7.6
Case 3	1 Injector 1 Extractor	1,212,810	1657	11.1

Scenario	Well Configuration	Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m^3/day	Storage Capacity, megatonnes
Case 4	1 horiz. Injector 1 horiz. Extractor	2,090,498	6701	19.1
Case 5	2 horiz. Injectors	1,953,238	*	17.8
Case 6	1 horiz. Injector 1 horiz. Extractor	*	6346	0.56
Case 7	1 Injector 1 Extractor	*	1599	0.15

Table 4: Case Scenarios and Resulting Storage Capacities for Teapot Dome

Simulations also examined the potential for surface water saturation using extracted water followed by injection of the CO_2 saturated stream. Due to low salinity formation fluids, it was found that this technique could result in a capacity of 0.15 Mt over a 25-year period utilising vertical wells (Case 7). This value was increased by utilising horizontal wells, resulting in storage capacity of 0.56 megatonnes (Case 6). While these numbers are significantly less than free-phase injections, they are still potential candidates because of reductions in MVA cost and increased storage security. Using the single well pairs in Cases 6 and 7, it was determined that in order to reach an injection rate of one megatonne per year using surface dissolution, that approximately 170 vertical wells (85 injection–extraction well pairs) or approximately horizontal 44 wells (22 injection–extraction well pairs) would be required. Due to the large number of wells, it is unlikely that surface dissolution is a viable option. Simulations at the Teapot Dome site indicate that water extraction can have an impact on storage capacity, reservoir pressure, and plume management. Utilisation of an injection extraction well pair resulted in increased storage capacity over the use of a single or pair of injection wells. Water extraction also strongly influenced reservoir pressures and plume migration. Although the overall size of the plume was not decreased with these simulations, eastward migration of the plume was reduced over the base case. The large plume was also thinner and exerted less pressure on the overlying cap rock. It is expected that extraction could be designed to reduce overall plume size at this site as well.

Water management options considered for Teapot Dome included reinjection into a geological formation and desalination for use as a potable or agricultural water supply. Reinjection could take place into several overlying options at a minimal cost.

The TDS of the extracted water is 9263mg/L and contains some hydrocarbons, though this is discounted for cost calculations. Simulations of reverse osmosis based water treatment were performed and the purified water yield from the 10,000 mg/L TDS brine was estimated to be 83% at a feed pressure of 69 bar and a feed temperature of 40°C. The purified water was calculated to have a salinity of 260 mg/L with product brine salinity of 57,600 mg/L.

The range of water price ranges from \$0.97/m^3 for the lowest extracted water flow rate (2600 m^3/day) at the 1 million tonnes/year of CO_2 injection to \$0.74/m^3 for the highest extracted water flow rate (59,600 m^3/day) for the 8 million tonnes/year of CO_2 injection.

This was compared to local water rates, and the cost of treating the extracted water (assuming no cost for removal of hydrocarbons) is less than the standard base rate of water in this area but greater than the rate charged per unit of water above the monthly minimum.

While Wyoming does not currently have primacy to regulate carbon storage through the Class VI well program, the state does have primacy to regulate Class II – Oil and Gas-Related Injection Wells, including disposal wells. Therefore as long as conditions are met, brine injection is not thought to be an issue.

Expert Review Comments

Expert comments were received from 7 reviewers, representing industry and academia. The overall response was positive and highlighted a significant contribution to this area of storage research. Suggestions included making the report clearer on the aims of the project and improvement on the report structure, consistency with units and increased clarity on amount of increased capacity. There were also some inconsistencies in one of the case studies. This was all addressed in the final report.

Conclusions

Extracting water from a CO_2 storage reservoir was observed to have variable effects based on the specific nature of reservoir rock and reservoir boundary conditions, as well as operational factors such as injection/extraction management and placement of wells. While the assumption of achieving a 1:1 ratio of injected CO_2 to extracted water was generally appropriate, in some situations, the volume of water which must be removed from the reservoir was much higher in order to perform the desired pressure or plume management tasks. The most influential results were found in the closed reservoir test performed at Zama. In this situation, extracted volumes were approximately equal to injected volumes. In other situations, it was found that the water extraction rate may be up to four times higher than the volume of injected CO_2.

Generally, the simulations conducted for this project illustrated that water extraction scenarios may be capable of increasing storage capacity by more than double. Site-specific factors affecting local injectivity resulted in the Teapot Dome site gaining more storage from an extraction/injection well pair and the Ketzin site storing more CO_2 with a pair of injection wells. Furthermore, optimising simulations to achieve pressure maintenance or plume management generally resulted in decreased reservoir storage capacity with a significant increase in the volume of extracted water.

It is unlikely that extracted water from storage locations in offshore or coastal area would be of beneficial use as potential cost savings of extracted water in place of seawater for desalination appears too small, even low salinities, 10,000 mg/L TDS.

In locations with formation waters with a high TDS, it is also unlikely that extracted water would be purified. While technologies exist to treat brines with the range of dissolved solids, the cost associated with treatment and implementation would likely be too high to justify. Treatment and beneficial use may be feasible under certain conditions: a combination of low-to-moderate extracted water quality, availability of inexpensive energy and sufficient local water demand. Of the case study sites, the best candidate for treatment and use of extracted water was the Teapot Dome site, where estimated treatment costs were comparable to that of local water supplies.

Surface dissolution involving the extraction of reservoir fluid, saturation, and subsequent reinjection is unlikely to be a viable option in most situations as the capacity of produced fluids to dissolve and carry CO_2 is too low. It is unlikely that this scenario will be able to compete with direct injection for storage of commercial-scale volumes of CO_2.

Existing regulations were not found that impose a barrier to the development of water extraction as part of reservoir management operations nor for the development of procuring additional water resources, provided the water quality is fit for the intended use. If extracted water is treated and utilised, effluent will be under regulations to adhere to wastewater treatment and handling.

Despite high costs and shortcomings encountered with extracting reservoir fluids for increasing reservoir capacity and/or management, it is important to consider these options for any specific storage site in an effort to:

- Optimise the injection scenario.
- Potentially alleviate costs through beneficial use.
- Reduce risk and MVA costs and increase reservoir efficiency by controlling plume migration.
- Manage pressure and injectivity.

Knowledge gaps and areas of additional and continued research were considered and the following list was thought necessary to address:

- Collect detailed water quality data for potential CO_2 storage targets, and develop a global database. This will aid in identifying targets with strong beneficial use potential and estimating the costs of water management strategies.
- Evaluate potential CO_2 capacity gains through additional site-specific research in order to increase known impacts of formation water extraction on CO_2 capacity.
- Evaluate additional strategies of CO_2 plume management using formation water extraction through detailed modelling and simulation activities. Evaluations of this type will help expand the knowledge of potential benefits of water extraction.
- Optimise injection simulation scenarios based on the distances between CO_2 injection and water extraction wells, using site-specific data, as

opposed to optimising the number of wells and/or their locations as was done in this study.

- Integrate additional chemical and physical phenomena, such as geochemical reactions and geothermal effects, into dynamic modelling simulators. Such integration will improve the comprehensive understanding of the storage–extraction system and provide more accurate estimations of storage potential and the utility of extracted formation water. This may be especially beneficial for evaluating cases of surface dissolution, where geochemical reactions are of a more immediate concern.
- Develop improved and more efficient methods of dissolving CO_2 directly into extracted water at the surface, as this would not currently be viable at most storage sites. This could lead to an increased utility of surface dissolution, and help more projects realise the potential benefits, such as reduced MVA costs.
- Develop efficient mechanisms to link potential sources of extracted formation water to potential users of treated extracted water. Once water is recognised as applicable for beneficial use, identify water supply shortages or bottlenecks in order to evaluate the economic benefit of the possible beneficial uses.
- Reduce the costs of extracted formation water treatment in order to increase the potential sources of extracted water that may be applied toward beneficial uses. Cost reductions may be found through improved technology, materials, or process efficiency.
- Conduct additional research to understand the economic benefits of formation water extraction on a site-specific basis. In particular, investigate how the benefit of increased storage capacity relates to the increased costs of the additional infrastructure required (additional wells, treatment facilities, etc.).
- Conduct additional research to evaluate the MVA cost savings associated with extracted water reservoir management versus the cost of the additional infrastructure required.
- Identify reservoir characteristics that may inherently enhance the effectiveness of formation water extraction strategies. This could lead to more effective usage of known and future storage targets.

- Develop formulaic methodology to estimate CO_2 storage capacity specific to the use of formation water extraction as a reservoir management strategy. This would allow for rapid assessment of the benefits of extraction on known and future CO_2 storage targets.

Recommendations

There is yet to be any large scale demonstration of this topic and most information is currently through modelling studies. It is recommended that IEAGHG continue to follow this topic and any updates, through future storage network meetings, namely the modelling network and by the study programme.

A future review of this topic would be useful as data is generated by future large scale demonstration projects.

2012-01 WELLBORE INTEGRITY NETWORK SUMMARY REPORT

Introduction

IEAGHG currently runs five international research networks on CO_2 geological storage, namely Risk Assessment, Wellbore Integrity, Monitoring, Modelling and Social Research. These networks meet on an annual basis, bringing together experts from industry, research institutions and regulatory agencies to discuss technical issues in the context of CCS deployment. Membership of the networks is open to those with a professional or academic interest in the particular network theme, and allows access to past network reports and presentations through the IEAGHG website, **www.ieaghg.org.**

The purpose of this report is to describe the Wellbore Integrity Network, summarise past meetings, outline key findings and identify current state of knowledge.

Technical Background and Network History

Wellbore integrity can be defined as the condition in wellbores that maintains isolation of geological formations, preventing vertical migration of fluids (Crow et al, 2010). Maintaining the integrity of wellbores is widely accepted as a vital issue for CO_2 geological storage, due to the requirements for sites to securely store CO_2 over long timescales. In cases where storage sites are located in sedimentary basins with a history of oil and gas exploration/ production, existing wellbores could represent the most likely leakage pathway from storage reservoirs to subsurface resources, environmental receptors or the atmosphere.

Despite the complexity of the topic, particular concerns regarding wellbore integrity and CO_2 geological storage can be simply summarised as follows:

- That injection of CO_2 (and any associated impurities) into geological formations will create a corrosive environment in which wellbore materials (steel and Portland cement) may be degraded, leading to loss of integrity and leakage of CO_2 and/or brine from the storage reservoir;
- That the presence in storage reservoir/caprock sequences of existing wells, which may have been constructed and/or abandoned to uncertain or poor standards, increases the uncertainty surrounding potential CO_2 and brine leakage. Poor standards of construction and abandonment

increase the probability of cement-free zones, mud channels in cement, and mechanical defects, such as poor bonding between well materials, which can compromise zonal isolation of fluids;

- That wellbore materials (steel and Portland cement) may not survive indefinitely (regardless of the fluids) and could pose a long-term risk of leakage (e.g., over the 100-1000 year time frame).

Research directed towards wellbore integrity and CO_2 geological storage has involved laboratory testing of cement and to a lesser extent steel samples in the presence of CO_2 and brine, theoretical modelling, analysis of data from industrial analogues such as the CO_2-EOR and acid gas (CO_2 and H_2S) disposal industries, analysis of data contained in databases maintained by regulatory agencies, and field studies of wellbore samples. There are continued efforts to obtain samples of cement and steel from wells that have been exposed to CO_2 within wellbores, for example in Phase II of the IEAGHG Weyburn-Midale Monitoring Project in Canada.

Given the importance of wellbore integrity to CO_2 storage, IEAGHG organised a network dedicated to this topic in 2005, with an initial vision for meetings to be held over a 5 year period. Table 1 below summarises subsequent network meetings which have, in total, attracted over 450 delegates from more than 20 countries.

Date	Host	Location	Number of Delegates
April 2005	EPRI	Houston, TX, USA	50
March 2006	Princeton University	Princeton, NJ, USA	57
March 2007	Los Alamos National Laboratory	Santa Fe, NM, USA	63
March 2008	Schlumberger	Paris, France	73
May 2009	Alberta Research Council, TL Watson & Associates	Calgary, Canada	77
April 2010	Shell	Noordwijk Aan Zee, Netherlands	59
April 2011*	University of Western Australia and Curtin University	Perth, Australia	75*
**Combined meeting with the Modelling Network*			

Table 1. Summary of Wellbore Integrity Network Meetings

Summary of Key Findings and Future Research Directions

When the network was initiated, the community was faced with the stark question of whether wellbore integrity was possible given the known chemical reactivity of steel and Portland cement with CO_2-saturated brine. Beginning with the first meeting, a great variety and number of experiments on cement and steel, field studies of wellbore systems, theoretical modelling, and operational/regulatory information have been presented at the Network meetings. As a result, the field has evolved significantly as captured in the proceedings of the network meetings with some of the key findings as follows:

- Durability of cement: field work and some experiments demonstrate that while Portland cement is reactive with CO_2, the rate of penetration is slow and the consequences to isolation may be of limited significance;
- Importance of interfaces: Initial concerns focused on the materials themselves, but research has demonstrated that the risk of leakage is associated with existence of interfaces between cement-steel and cement-caprock that exist either due to poor completions or to mechanical degradation;
- Corrosion of steel: steel reactivity is more rapid than cement and had been neglected in earlier research;
- Geochemistry: Rather than a prime-factor in wellbore integrity, geochemical reactions are now viewed as either aggravating or ameliorating existing leaks through dissolution or precipitation;
- Self-healing in wellbore systems: Experimental studies have shown that precipitation of calcium carbonate in cement and iron carbonate in corrosion reactions can reduce permeability of interfaces and could limit wellbore leakage;
- Origin of wellbore problems: The most significant processes in the loss or lack of zonal isolation are failure to place cement adequately at the time of completion and subsequent geomechanical stresses induced by pressure changes, thermal fluctuations, and wellbore operations including mechanical integrity tests;
- Cement formulations: CO_2 resistant cements have been developed; expansive cements (for sealing microannuli) have been described; non-Portland cement systems have been considered; and differences

between neat Portland cement compared with pozzolan (flyash)-bearing cements have been demonstrated;

- Wellbore permeability: This remains a key research need, but substantial progress has been made with field measurements of effective wellbore permeability and experimental studies of cements with defects, both of which suggest effective permeabilities of the order of 1 mD;
- Factors governing wellbore performance: Databases were developed that allow correlation of wellbore attributes with likely wellbore performance as measured by sustained casing pressure (aka surface casing vent flow), gas migration and casing failure, and provide a key risk assessment tool;
- Co-contaminants: Reaction of co-contaminants (H_2S) with cement have been initiated and thus far have not been found to be significantly more deleterious to cement;
- Record of CO_2 operations: The network meetings have not revealed any significant accidents or environmental impacts associated with CO_2-EOR operations lending greater confidence in the ability to manage well integrity;
- Materials in wellbores: Research suggests that proper use of carbon steel and Portland cement may be adequate and that stainless steel and special cement formulations may be less critical to achieving well integrity.

Significant challenges as well as untapped research potential remains in the wellbore integrity field. The following research areas represent potential topics or themes for future network meetings:

- Long-term integrity: Almost no work has been done to consider the very long-term (100-1000 years) durability of cement and steel and the implications for long-term storage security;
- Multiphase flow processes in wells: Current leakage models in wells are based on Darcy flow and do not adequately represent multiphase flow in fractures/interfaces characteristic of wellbore defects;
- Permeability: Effective permeability of wellbore systems are still poorly known and needed in risk assessment;
- Frequency: What features of wells (age, materials, completion details) represent increased potential for wellbore failure and how frequently do wells fail?
- Leak detection: The ability to detect, locate and quantify wellbore leakage

is not yet sufficient;

- Geomechanics: Models of the impact of stress due to injection/production activities on wellbore integrity including formation of microannuli, fracturing of cement or caprock, and deformation of steel;
- Coupled geomechanics with flow and reaction: Analysis of the potential role of stress in creating fluid flow pathways in the wellbore coupled with determination of CO_2/brine flow rates and the consequences of geochemical reactions on modifying the effective permeability of the mechanical defect;
- Coupled experiments: Experiments that couple stress with flow of CO_2-brine through synthetic wellbore systems (steel-cement-rock) designed to illuminate flow mechanisms, permeability, and self-healing;
- Self-healing: Under what conditions do geochemical (precipitation) and geomechanical (deformation) processes seal wellbore defects?
- Fate of leaking fluids: Are (near) surface or subsurface aquifers the most likely destination of leaking CO_2 and brine and what factors control this behavior?
- Shale gas analogue: Analysis of the experience of methane leakage in the shale gas industry may be very instructive with respect to frequency and mechanisms of wellbore failure (that are certainly the most significant cause of problems) as well as the migration and geochemical impact of gas through the wellbore;
- CO_2-EOR: Relatively little information has so far been obtained from the vast experience available in the CO_2-EOR industry with particular reference to the frequency and cost associated with remediating old wells during initiation of CO_2 floods;
- Regulatory data: Significant opportunities exist in regulatory databases on wellbore performance including mechanical integrity test data, accident frequency, and remediation activities.

The problem of wellbore integrity is nowhere so acute as when considering CO_2-EOR as sequestration or storage in depleted oil and gas fields (Carbon Capture Utilization and Storage, CCUS). While not applicable in many regions, CO_2-EOR offers tremendous potential as a technology bridge to saline aquifer sequestration because of the potential financial offsets gained from oil production. However, this will not be possible without an effective strategy for well integrity.

Network Findings

2005 Meeting

The first network meeting in Houston set out some of the key issues for wellbore integrity and storage, as follows:

- Ensuring wellbore integrity over long timescales presents a novel challenge for the oil and gas industry. Whilst application of 'state of the art' technologies can reduce risks associated with leakage, it is impractical to absolutely guarantee a 'leak-free' well;
- Standard Portland cements will react with CO_2 – portlandite and calcium silicate hydrates convert to carbonate minerals such as aragonite and calcite, with potential impacts on wellbore integrity. Laboratory experiments can simulate these reactions but extrapolation to field reaction rates is problematic due to unrealistic laboratory conditions;
- Alternative cements resist carbonation reactions by reduction/elimination of portlandite, or use of inhibitors – however the use of such alternative materials may significantly increase costs and have not been widely tested in field settings;
- Studies of wellbore issues from the CO_2-EOR industry represent the most appropriate industrial analogue to provide data on likely failure rates and associated processes and to inform storage risk assessments and risk management strategies.

The meeting also identified key research needs at the time, including definitions for failure criteria, acquisition of detailed data from industrial analogues, further understanding of cement failure including by sampling of wells exposed to CO_2, and standardisation of testing procedures.

2006 Meeting

The 2006 meeting highlighted wellbore integrity issues within the oil and gas industry. The meeting heard that up to 60% of wells offshore in the Gulf of Mexico experienced Sustained Casing Pressure (SCP) problems, compared, for example, with only 6% of the wells in Alberta that experienced Surface Casing Vent Flow (SCVF, equivalent to SCP), possibly indicative of compromised wellbore integrity. In the US Permian Basin, oil fields switched to CO_2 flooding typically required major remedial work on existing wells not previously exposed to CO_2 – involving pulling tubing and re-cementing activities. These various problems could be attributed to such factors as poor removal of drilling mud or poor cementing practices. Inadequate sealing could allow circulation of saline water, inducing corrosion of casing and deterioration of cement. The meeting heard that the American Petroleum Institute (API) had recognised these various problems and, in response, API was developing guidelines and standards for well completions and CO_2 floods.

The meeting also heard how cement samples taken from a well exposed to CO_2 in the Permian Basin showed limited alteration in comparison to some of the dramatic degradation of Portland cements caused by CO_2 in laboratory experiments. The design of new CO_2-resistant cements was welcomed by industry representatives but caution was also expressed on cost and performance aspects of such new cements.

2007 Meeting

Delegates at the 2007 meeting agreed on the continued significance of wellbore integrity, emphasised by presentations and discussions at the meeting concerning the issue of wellbore integrity in the context of developing wider CCS regulations.

An ongoing theme from previous meetings was the discrepancy, in terms of cement resistance to CO_2-induced degradation, between some laboratory experiments that showed rapid and deleterious CO_2-induced degradation of cement compared with field-based observations indicating decades-long persistence of cement in the presence of CO_2. Despite the advances in understanding of reactions and processes since the previous meeting, discussions highlighted the need for continued research on this topic.

Another significant aspect of the discussions addressed risks associated with old and abandoned wells in regions of intensive oil and gas industry activity. Two examples described were Alberta, where a large repository of information is available on historical wells, and in contrast Texas where records of up to 1 million old wellbores are highly variable. Delegates discussed the importance of the issue for storage site selection, and agreed the need for more research in the absence of defined standards for re-completing old wells.

2008 Meeting

The 2008 meeting included presentations describing wellbore experiences in two important oil and gas regions, the Norwegian North Sea and Alberta. In the former, between 20% and 30% of all wells had at least one leakage incident recorded, representing an apparent dramatic rise from the 1990's that could be due to increased awareness and reporting of problems. Cement failures were not known to be the cause of any problems, however. From a detailed study of 79 wells in Alberta used for CO_2 or acid gas injection, initial conclusions included that purpose-built injectors performed better than converted wells, and that a majority of wellbore integrity issues were caused by tubing and packer problems. Moreover, these failures could occur in wells that utilised CO_2-resistant cements.

The meeting included talks from various organisations concerning ongoing research programmes into cement carbonation and degradation. Discussions amongst delegates again highlighted discrepancies between laboratory test results and operational experience within industry, backed up by field data. An important knowledge gap identified was the mechanical behaviour of cements exposed to CO_2 over long timescales.

Presentations and discussions on the topic of predictive modelling highlighted the serious challenges faced by researchers in developing quantitative assessments of wellbore performance, especially over extended timescales. Regulators are likely to require quantitative models of long term storage site performance, as part of overall risk assessment and management plans, and wellbore integrity may have to be incorporated in such models for many sites. An example of the detail to be resolved is the understanding of processes that may affect the wellbore-formation interface, and the condition of the geological formations in the immediate vicinity of the wellbore.

2009 Meeting

The 2009 meeting in Calgary attracted significant interest from industry, reflected in the composition of the delegates list and by a number of presentations. Delegates viewed data which showed reductions in oil and gas industry well blowouts between 1991 and 2005, attributed to improvements in engineering design and management practices. The meeting also heard examples of successful re-plugging of old/abandoned wells from North

American CO_2-EOR projects, and on the development of alternative plugging materials to conventional cement that have been successfully applied to well completion and remediation problems. The potential importance of old/abandoned wells to CCS projects was highlighted by discussion of the De Lier gas field in the Netherlands, which was not pursued as a CO_2 storage site because of the technical challenges and associated costs of re-plugging old wellbores – some being present in an urban environment.

Another key topic of discussion was around definitions – leakage is a critical concern for CCS projects, but some industrial analogue data may include small scale, near-surface integrity issues which would not necessarily affect storage integrity.

The meeting also allowed continued debate on the challenges of extrapolating long term cement performance predictions from accelerated laboratory experiments; recent research by the DOE/NETL in the USA had produced encouraging results during attempts to calibrate experiments with field data. Nevertheless, the meeting heard how risk assessments of wellbore integrity for CO_2 storage remained essentially qualitative or semi-quantitative, relying heavily on expert judgement supported through analogue data. Also agreed by delegates was the importance of effective monitoring of wellbores for leakage as a risk management tool.

Summing up the meeting discussions, an apparent dichotomy was evident between the confidence of industry representatives who emphasised the practical experience of successful CO_2-EOR projects dealing with wellbore integrity issues, and the caution of storage researchers who stressed the novel aspects of industrial scale CO_2 storage – including long timescales, regulatory/public perceptions of risks associated with leakage, and reservoir pressurisation.

2010 Meeting

Whilst the 2010 meeting was well attended, albeit with fewer delegates than the previous meeting, setting an agenda for the full 2 days proved challenging for the steering committee; ultimately there was a heavy reliance on hosts Shell, and Schlumberger, to contribute presentations. However, the meeting began just as the Macondo Well blowout occurred in the Gulf of Mexico, providing a dramatic highlight to discussions of wellbore integrity.

A study undertaken by TNO on behalf of IEAGHG, commissioned as a result of previous network meeting discussions, was reported to the delegates. The study looked at wellbore abandonment practices from a geographical and historical perspective. A central conclusion of the report was that old wellbores will present a major risk consideration for many sites, whereas newly constructed wells should be associated with minimal risk. Other talks at the meeting also underlined that recent advances in wellbore technology should minimise risks associated with new wells. For example, API reported that of 15,000 operational CO_2-EOR wells in the USA, only 0.009% experienced serious operational problems due to a 'loss of control'; these statistics do not include minor leakage incidents that can be readily repaired. Picking up on this theme, the meeting heard arguments that leakage needs to be assessed in terms of risk (i.e. taking into account potential impacts) so that possibilities of minor leaks do not assume exaggerated importance to CCS projects.

The assessment of risks associated with old wells would continue to be a focus of future research but is site-specific in nature. Delegates agreed that most storage reservoirs can be assessed and risk managed using available data and well records, with re-plugging undertaken as necessary but subject to cost factors.

Latest developments in corrosion studies of wellbore materials reported to delegates tended to focus on the importance of micro-annuli and material interfaces, providing potential pathways for CO_2 migration and enhanced corrosion. The meeting heard how many processes could promote 'self-healing' of pathways through factors such as mineral precipitation. Similarly, shale creep could be utilised as a 'self-healing' process to augment zonal isolation measures for abandonment.

2011 Meeting

Following the problems encountered by the steering committee in setting an agenda in 2010, the 2011 meeting was held as a combined meeting with the modelling network; wellbore integrity issues were discussed in a dedicated session.

The meeting heard from two initiatives to publish guidance on wellbore integrity issues for CO_2 storage. The US Regional Carbon Sequestration Partnerships (US RCSP) programme had compiled best practice guidelines for drilling, well installation, operations and closure. A Joint Industry Project on guidelines for wells, led by DNV, was also reported to the meeting; delegates heard that monitoring will be emphasised as a critical element in the guidelines, and that predictive modelling will be recognised as essential component in the risk management process.

Other presentations included updates on recent efforts to predict cement performance from laboratory tests, with results that allowed for self-healing characteristics of processes such as precipitation of new phases in pores. Results therefore tend to better replicate operational experiences. The meeting was also updated on the field sampling exercises undertaken as part of the IEAGHG Weyburn-Midale project, with results due to be published in 2012.

Summary: Current State of Knowledge

Given technological advances in drilling and improvements to management practices in the oil and gas industry, there is a strong argument that risks associated with new, purpose-built wells at storage sites can already be adequately managed and are likely to be actively monitored. Conversely, existing wells have been subject to variable standards of construction, operation and abandonment according to such factors as age, regulatory jurisdiction and geographical location and may be difficult or expensive to monitor. Poor practices are more likely to have resulted in defects that can allow vertical fluid migration in such wells. The presence at some storage sites of existing or abandoned wells remains a complex risk management issue that will require effective monitoring programmes and possibly remediation works, as have been applied at some CO_2-EOR sites.

Many of the presentations and discussions at network meetings have inevitably revolved around the potential effects of CO_2 injection on wellbore materials, and particularly on cements. Zhang and Bachu (2011) provide a review of both mechanical and chemical factors that can lead to wellbore integrity issues for existing wells, with a focus on the complexity and phasing of reactions that can affect cements as witnessed by both laboratory experiments and field samples. Initial reactions between CO_2 rich brines and conventional cements are likely to result in the precipitation of calcite, which is likely to reduce permeability by 'clogging' pore spaces and fractures.

Laboratory experiments have shown that subsequent exposure to brine in a "high-flow" environment can lead to calcite dissolution and degradation of the cement; however, this may be mitigated by the presence of calcite in reservoir rocks, which would mean that brines were already in equilibrium with calcite and thus unlikely to result in dissolution. In the absence of flow that would wash/flush away the calcite, further cement degradation is likely to stop, as diffusion is a very slow mechanism for bringing CO_2-saturated brine in contact with original cement.

Priority areas for further research identified in network meetings include:

- Standard definitions for wellbore integrity issues that can be applied to CO_2 geological storage;
- Mechanical properties of carbonated or degraded cements;
- Further field sampling of wellbore materials that have been exposed to CO_2 at reservoir conditions, allowing improved understanding of processes and calibration of laboratory experiments/theoretical modelling;
- Development of quantitative modelling and integration into storage site risk assessments;
- Effective monitoring strategies for wellbores and potential leakage.

Conclusions

The network has provided a valuable international forum for discussion of wellbore integrity issues pertinent to CO_2 geological storage since its inception in 2005. The network meetings have presented detailed information from industrial analogues to storage, especially from the oil and gas industry including North American CO_2-EOR and acid gas disposal projects. Statistics on wellbore leakage and failure rates have been presented and discussed, whilst best practice guidelines have been debated.

Research over the last 6 years has greatly improved our understanding of processes linked to potential alteration and degradation of wellbore materials, especially cements. Much of the relevant research is included within presentations made at network meetings.

Presentations and discussions at network meetings have indicated that wellbore integrity issues for new, purpose-built CO_2 injection and monitoring wells should be manageable with appropriate use of best practice guidance, backed by experience from the oil and gas industry. The presence at some storage sites of existing or abandoned wells remains a more complex risk management issue that will require effective monitoring programmes and possibly remediation works, as have been applied at some CO_2-EOR sites.

Quantitative prediction of wellbore integrity over longer timescales, and integration into risk modelling for storage sites, remains challenging and will require continued research effort as the number of large scale storage projects associated with CCS deployment increases over the coming decade.

Although recent network meetings have continued to attract significant numbers of delegates, the steering committee has found increasing difficulty in setting agendas that incorporate new research. This was particularly problematic in 2010, and led to the decision to hold the 2011 meeting in combination with the more recently instigated Modelling Network, which has attracted greater numbers of delegates and volunteers for presentations. On the other hand, there is continued recognition that there remain important research questions in wellbore integrity that create uncertainty in the long-term storage of CO_2.

Recommendations

Whilst wellbore integrity remains an important topic for storage, IEAGHG should consider whether current levels of new research warrant a dedicated network. The topic could alternatively be incorporated in other network meetings (Risk Assessment, Monitoring, Modelling), or the network could be revived at an appropriate point in the future when warranted by information from new research and increased numbers of storage sites. Another possible alternative is to held meetings every two years rather than annually.

Collectively, the presentations made at network meetings since 2005 constitute a useful body of knowledge. IEAGHG should consider an indexing or database system to allow network members to make full use of the information.

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- Stefan Bachu, Alberta Innovates Technology Futures
- Bill Carey, Los Alamos National Laboratory
- Mike Celia, Princeton University

IEAGHG also acknowledges the support of the various network meeting hosts and sponsors since 2005.

2012-05 SUMMARY REPORT OF THE 6TH IEAGHG RISK ASSESMENT NETWORK WORKSHOP

Introduction

The 6th IEAGHG Risk Assessment Network Workshop was held from the 21st to the 23rd of June in Pau, France hosted by BRGM; sponsored by BRGM and International Performance Assessment Centre for the Geological Storage of Carbon Dioxide (IPAC-CO2). 54 participants attended the workshop from 15 different countries.

The three day workshop highlighted the latest international CO_2 storage risk assessment developments, discussing communication and regulatory developments, risk and incident management, potential induced seismicity, monitoring performance, understanding potential groundwater impacts, risk assessment methodologies, key outcomes and identified knowledge gaps which need to be addressed in future research. Participants were fortunate to visit the TOTAL Lacq-Rousse project on the 3rd day of the workshop, including the oxy-combustion capture site and the storage site in the afternoon, with a TOTAL sponsored lunch.

The agenda and presentations from the meeting are available in the network members' area of the IEAGHG website (www.ieaghg.org). The previous workshop agenda, presentations and report are also detailed on this website. The 6th IEAGHG Risk Assessment Network Workshop was organised by IEAGHG in co-operation with BRGM. The organisers acknowledge the financial support provided by BRGM and International Performance Assessment Centre for the Geological Storage of Carbon Dioxide (IPAC-CO2) for this meeting; the hospitality provided by the hosts, BRGM, at the Le Palais Beaumont, Pau, France and, for the hospitality provided by TOTAL during the site visit to the Lacq-Rousse project.

An International Steering Committee guides the direction of this network. The International Steering Committee members were:

- Ameena Camps, IEAGHG (Chair)
- Olivier Bouc, BRGM (Co-Chair; Host)
- Tim Dixon, IEAGHG (Co-Chair)
- Hubert Fabriol, BRGM (Host)
- Adrian Bowden, URS

- Grant Bromhal, USDOE/NETL
- Rick Chalaturnyk, University of Alberta
- Kevin Dodds, BP
- Charles Jenkins, CSIRO and CO2CRC
- Angeline Kneppers, GCCSI
- Jerry Sherk, IPAC-CO2

The International Steering Committee also wish to acknowledge Pauline D'Armancourt of BRGM for all her work in organising the logistical aspects of the meeting; Claudia Vivalda for her expertise and advice during programme discussions, and Samantha Neades of IEAGHG for her organising prowess.

Session 1: Risk Communication & Regulatory Developments Chaired by Tim Dixon

Suzanne Brunsting of ECN presented lessons learnt from risk communication of the Barendrecht project in the Rotterdam area of The Netherlands, cancelled in 2010 following public opposition. A survey conducted in Barendrecht concluded the majority of the population were aware of the project; however there was little knowledge of the technology itself with 80% of those surveyed believing the decision-making process was unfair. Primary concerns were related to safety and very little appears to have been communicated to allay these concerns. The project highlights the importance of risk communication to discuss uncertainties and provide trusted information, having a dedicated public outreach team and an independent mediator, facilitating public participation as part of a formal risk assessment.

Since the last Risk Assessment Network (RAN) Workshop, the Canadian Standards Association have been developing a CO_2 standard, bringing together the best practices and guidelines for a standard up to the transfer of liability. Rick Chalaturnyk of Calgary University presented an update on the development process with an aim to enable an International standard. The final EU Guidance Documents to support coherent implementation of Directive 2009/31/EC on the geological storage of carbon dioxide have been published. Raphael Sauter of the European Commission discussed the CCS Directive and the Guidance Documents to support the coherent implementation of the CCS Directive, presenting the CO_2 Storage Life Cycle Risk Management Framework and relevant risk aspects including: guidance for a monitoring plan to be risk based, scope and format of corrective measures plans and integration with the EU ETS. The Session discussion focussed on decision 7 of the Sixteenth Session of the Conference of the Parties to the UNFCCC/Sixth Session of the Conference of the Parties serving as the Meeting of the Parties to the Kyoto Protocol (UNFCCC COP 16/ CMP 6). This decided CO_2 capture and storage in geological formations is eligible as project activities under the Clean Development Mechanism (CDM) provided issues identified are addressed and resolved. Discussion aimed to carry forward RAN points and recommendations to the upcoming technical UNFCCC workshop on modalities and procedures. Delegates highlighted the importance of focussing on the objectives of risk assessment rather than the methodology used, questioning the terminology used in the decision text; questioned whether consideration of non-GHG issues was relevant for the CDM; noted the iterative nature of risk assessment, hence process throughout the lifetime of a project is important and recommending the use of an expert panel or network of experts to support the UN system.

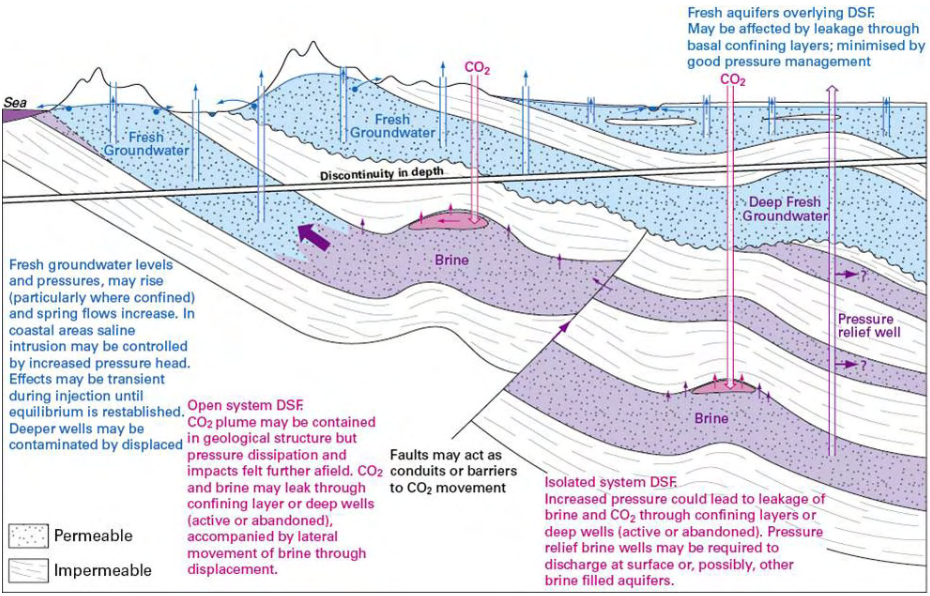
Tim Dixon of IEAGHG

Session 2: Understanding Potential Groundwater Impacts Chaired by Ameena Camps, IEAGHG

There are several challenges in predicting potential groundwater quality impacts; including heterogeneity and rate limited chemical reactions. These highlight a time scale issue; which to understand requires the integration of laboratory and field data. Elizabeth Keating of Los Alamos National Laboratory presented results from field, laboratory and modelling studies at a natural analogue site Chimayo in New Mexico, USA: a shallow sedimentary aquifer where there are a lot of trace elements in the water and soil. Beneath the shallow water aquifer, which is highly dissected by faults with CO_2 flowing up-dip, is a carbonate layer with brackish water. Trace elements have been found to be associated with the brackish water; in-situ mobilisation is negligible; and CO_2 entrains the trace metals from the deeper layer bringing them to the surface not mobilising the trace metals; showing the system is dominated by reactions below the aquifer and brine displacement is more important than reactions in the shallow aquifer.

Julie Lions presented the results of the IEAGHG study: Potential Impacts on Groundwater Resources of Deep CO_2 Storage, a review summarising the current knowledge and identifying research priorities. GIS approach has been used to determine possible over-laps/conflicts between freshwater aquifers and deep saline formations with potential for CO_2 storage in Europe and North America; however hydrogeological data used does not contain depth data therefore site specific information in required. Areas with potential deep saline formation storage overlain by aquifers include: onshore in Germany and the Paris Basin and should be further considered. There are limited analogue and experimental studies, and in the field there is no impact directly observed on fresh groundwater in the CCS context, with large variability in modelling results. Hydrodynamic models show the effect of pressurisation to be much larger than the area associated with the plume; however brine displacement was found to be only over a very small distance and unlikely to affect groundwater resources. The study considers mitigation methods. Careful design of storage operations will minimise risk.

GCCSI established a thematic group in 2010 on the theme of Managing impacts of CO_2 storage on groundwater which held its first workshop in May 2011 focussing on Australian flagship regions. There are four main regions including the proposed Collie Hub project, Perth Basin; Wandoan, Surat Basin and CarbonNet, Latrobe Valley all at varying stages of development; and the existing Otway project in the Otway Basin which has groundwater monitoring stations in place demonstrating no change has occurred between pre-and postinjection. The workshop identified there is a poor level of knowledge about deep saline formations and their interaction with other water bodies, convergence of 3D modelling between groundwater and resources is required, unnecessary prescriptive monitoring should be avoided.

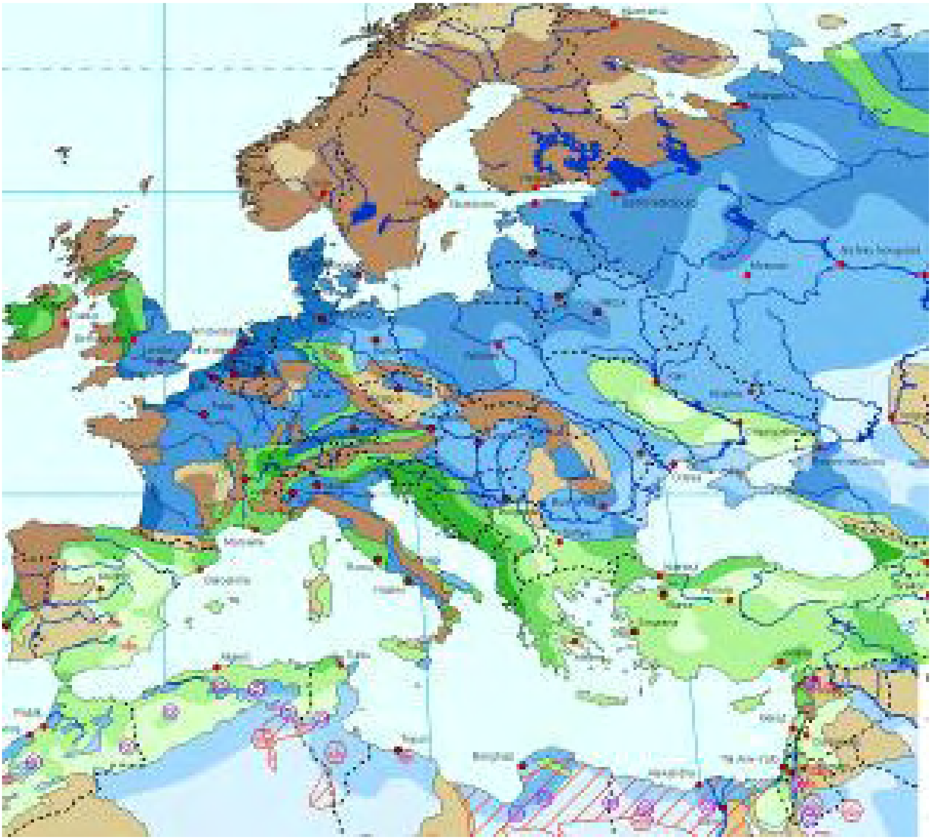


Schematic potential impact mechanisms on gw resources, Courtesy of Julie Lions, BRGM

groundwater baseline data for the flagship projects, consider how to avoid excluding groundwater bodies that could be considered unsuitable for CO_2 storage but are not potable and ensure consistent communication.

Potential impacts on microbial populations and implications for groundwater was highlighted as a knowledge gap at the 5th RAN workshop and Julia West of the British Geological Survey was invited to present research results in this field.

Microbes will exist in geological settings relevant to CCS. Nutrient and energy supplies for microbial growth, as well as microbes themselves, may be introduced into the deep subsurface through CCS activities, and each CO_2 migration scenario will impact on indigenous microbial populations. Microbes are unlikely to survive in supercritical CO_2 environments, however many will survive and thrive in contact with CO_2 gas or dissolved phases generating biofilms. CO_2 can act as an energy source by methanogens which can impact on the oxidation of minerals. Resulting physical impacts from microbial activity on the reservoir includes the alteration of porosity impacting injectivity (as seen at Ketzin due to not adding a biocide on injection); and chemical impacts include change in pH, mineral formation or degradation and mobilisation of trace elements. Models to understand microbes and groundwater do not consider microbes which catalyse geochemical processes. Microbial effects may be small or undetectable in initial period of storage but is site specific and the effects of CO_2 injection needs to be evaluated.



Groundwater Resources in Europe, WHYMAP, Courtesy of Julie Lions, BRGM

Session 3: Methodologies, Chaired by Rick Chalaturnyk, University of Alberta

Matt Gerstenberger of GNS Science discussed the results of a project examining various risk assessment methodologies for CCS. Risks can come from anywhere in the system and are not independent; hence an integrated system assessment will highlight greatest risks. It is important to identify what we know and how well we know it for risk assessment. Much of our knowledge comes from modelling which is insufficient for risk assessment; expert judgement will almost always be required. Uncertainty can be dealt with through expert elicitation to help guide the process, to further understand probabilities and draw components of risk assessment together. Structured expert elicitation guidelines are available, including the Cooke methodology, providing an iterative process, a workshop environment with weighted group response though the questions posed are key for an effective weighted response. Future risk assessments should consider the development of conditional probabilities, structured expert elicitation, weighted expert judgement and open methodologies.

Developing a common rational and operational Methodology of ANAlysis Unified and management of risks for CO_2 geological Storage within the French context, Yann Le Gallo of GeoGreen presented preliminary results of MANAUS. The projects final output will be a methodological guide, providing a review of tools and methods for risk analysis, functional analysis for storage, risk scenarios, uncertainty management and impact potentials. Commercial flow and geochemical models and software for uncertainty analysis have been examined with comparison studies of high level functionalities of models. Models have been ranked for suitability, and some proved unsuitable for CO_2 storage. Strengths and limitations of methods and tools for analysis have also been considered.

Adrian Bowden of URS presented Biosphere and Geosphere risk assessment process using the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage project as an example. Many technical inputs are considered in geosphere risk assessment and the outputs identify what risk events, and the likelihood of such, may move CO_2 from the geosphere to the biosphere. Biosphere risk assessment then identifies the risks to biosphere assets with ranking and severity, applying EIA methodology to CCS. Community engagement is then used to ascertain what the community believe are pertinent considering valued assets. At Weyburn wells were identified as the key risk issue, and community valued assets included camping areas and native prairie habitats. A workshop forum can be used to bring together technical studies on risk components and identify required expertise with each specialist providing a summary of key findings. A consequence table can be used to estimate potential impacts. It is important to engage at all levels and involve a different expert network.

Max Watson of BP presented the new BP concept and tool, integrating dynamic changes in CO_2 storage system relative to leakage risk mechanisms through time and space: Quantitative Risk Through Time (QRTT). This uses the inclusion of dynamic aspects such as the degree of trapping, the pressure, and what are these attributes in time. Risks will change as the CO_2 storage reservoir evolves with time i.e. once the plume reaches the trapping structure there will be seal risks, once in chemical trapping phase the risks drop significantly. Monitoring will be based on the risk plan and to the project design will aim to reduce risk. As injection begins, the model can be used to match performance with time, identifying the level of risk with time. QRTT has been successfully demonstrated on In-Salah but requires further demonstration.

Presenting on behalf of Grant Bromhal of US DOE/NETL, Elizabeth Keating of Los Alamos National Laboratory highlighted the latest developments of the National Risk Assessment Partnership (NRAP), specifically associated with longterm quantitative risk profiles. NRAP is using an integrated assessmentmodel approach to predict site performance, including a model for risk profiles in groundwater systems calculating the dynamic evolution of risk proxies such as pH and Total Dissolved Solids (TDS), using a wellbore-release model to calculate potential CO_2/brine leakage rates based on pressure and saturation, and a reservoir model to predict pressure and saturation at the reservoir-caprock interface. Results have identified preliminary risk profiles showing recovery initiates after injection ceases and impact probability decreases with distance from release. Following focus on quantification methodology and tools, in the next two or three years the US DOE will focus on the science base to reduce uncertainty then integration of monitoring and mitigation strategies.

To examine measurements of meaning and question uncertainty, Ken Hnottavange-Telleen of Schlumberger Carbon Services discussed how we identify sources of risk, subdivide risk and apply a quantitative estimation of how we understand that risk, given there is no 'completeness' in risk identification so thoroughness is the best we can achieve. New conception of risk may be the product of applying metathinking to identification of risks, assisting in the thoroughness of risk assessment.

Discussion reiterated the importance that though the methodology used for risk assessment of a project should be traceable, selection of a methodology should be specific to a project and, rather than examining or attempting to compare methodological approaches the verification of communication should be the main focus. Risk Assessment should provide guidance for decision makers.

Lecture Hall at the Venue

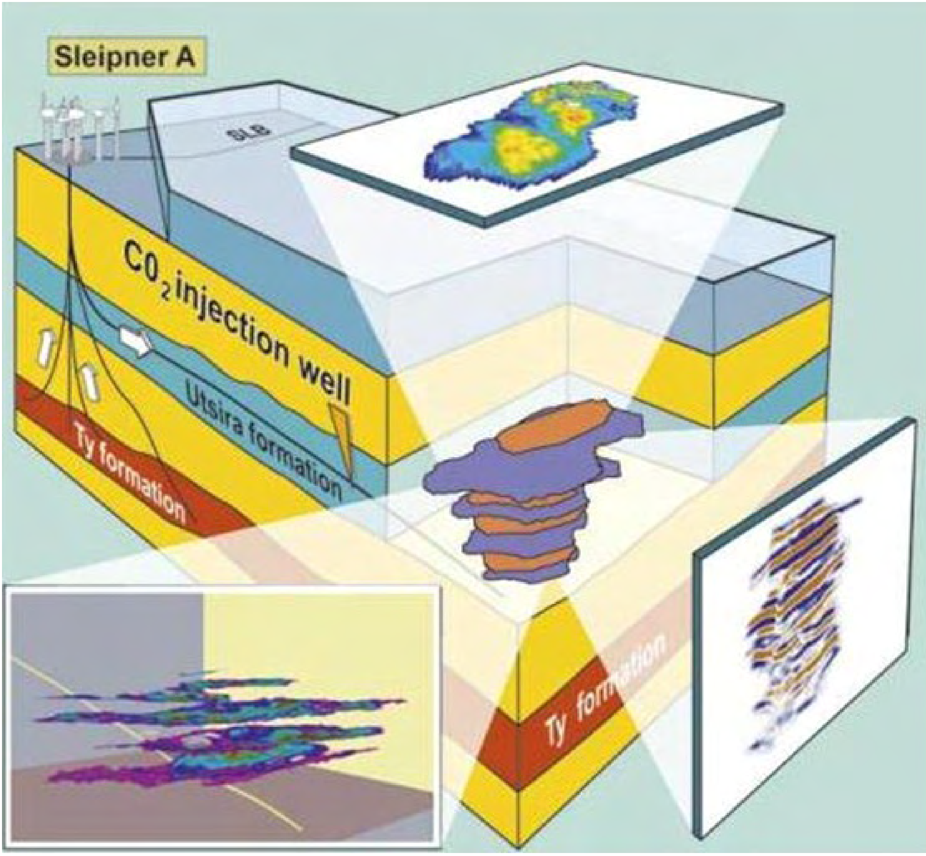
Session 4 : Risk and Incident Management, Chaired by Angeline Kneppers, GCCSI

Presenting and discussing the IEAGHG Weyburn Midale CO_2 Monitoring and Storage Project's response to claims of a CO_2 leak, Rick Chalaturnyk of the University of Alberta; on behalf of Norm Sacuta from PTRC; highlighted the history of testing at the Kerr farm from initial water testing by Saskatchewan mines and energy to the Petro-Find claim of a shift in the isotopic concentrations in soil gases. With the detailed monitoring program and knowledge of the injected isotopic concentration, PTRC response shows there is no evidence for a change in isotope concentrations in soil gas due to the project, and all values are within the range of naturally occurring CO_2 in soils in Saskatchewan; hence the phenomena observed can be explained by near surface processes. Further investigations are underway. This highlighted a process for management, including development of communication tools such as key messages, establishing a point of contact and the production of an official response; in addition to reinforcing the importance of baseline measurements.

Thomas Le Guenan of BRGM presented GERICO, a database for geological CO_2 storage risk management which aims to be a communication tool for risk treatment measures, similar to the IEAGHG Monitoring tool, following recognition of the importance of more emphasis needed in risk treatment. The database orders risk mitigation measures according to causes and consequences of a top event. The tool or database is in development and once the first version is finalised it will be made available online in French and English, potentially linking with the IEAGHG Monitoring tool.

DNV have developed a new guideline – CO_2WELLS - during a joint industry project, supplementing the CO_2QUALSTORE guideline. The guideline provides guidance on the risk assessment of active and abandoned wells during the initial screening of a candidate storage site and the qualification of these wells for continued use or modified use. Though primarily for existing well stock this risk management framework can also be used as a basis for new well stock qualification. Mike Carpenter of DNV presented and discussed the new guidelines which are consistent with current emerging regulations and the ISO31000 international standard for risk management.

Discussion raised the importance of further consideration of the EC requirement for data access on transfer of responsibility and difficulties which may be encountered for a data repository; for example in accessing data for wells outside the zone of the plume or legacy data for risk assessment purposes.



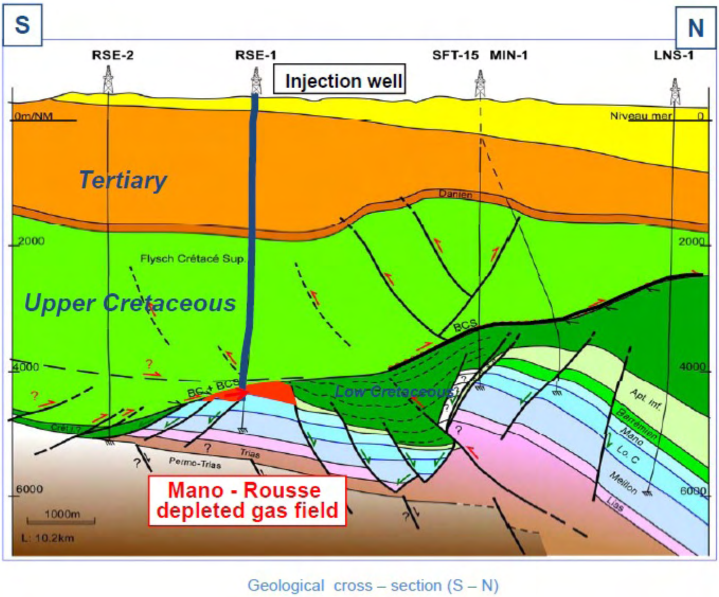
BGS/IEAGHG Monitoring Tool, Courtesy of Thomas Le Guénan

Session 5: Induced Seismicity, Chaired by Adrian Bowden, URS

Joëlle Hy-Billiot of TOTAL presented the Lacq-Rousse pilot project in France and results of micro-seismic monitoring at the Rousse storage site. The storage site is a depleted gas reservoir, a fractured dolomitic reservoir, with a depth of 4500m and initial pressure of 485 bar, overlain by 200m caprock with carbonates and shales. Monitoring aims to answer identified potential risk scenarios through preinjection, injection and 3 years of observation. Microseismic monitoring network consists of one deep array, seven subsurface arrays in shallow wells above the reservoir with one surface seismometer. Baseline was carried out in 2009 with only the subsurface network. Injection began January 2010. The network can record events as low as -3. In 2010 very low magnitude (-1.1 to -0.2) very near seismic events were detected below/in the reservoir, possibly due to injection or production. Since April 2011, very low magnitude microseismic events have been located from 100m to 600m from injection identified (3.1 to -1.4). As part of the risk management process there are varying levels of alarm e.g. if there is an event of magnitude more than 5 then need to cease injection and check operations. Events have been much lower than that. The project highlights a logical progression from risk analysis to implementation and definition of alarm thresholds.

Induced seismicity is a recognised risk in any Earth-engineering endeavour that changes the stress state or pore pressure of a rock mass, including oil and gas production, mining, enhanced geothermal system (EGS) development. Drawing on his past experience, Nicholas Deichmann of ETH-Zurich discussed lessons learnt from induced seismicity connected with the exploitation of deep geothermal energy; highlighting non-EGS cases and those of deep geothermal systems, explaining the difference between 'induced' and 'triggered' seismicity. The Basel EGS project developed a traffic light system of how operators would react to seismicity dependent on magnitude of events. In 2006/2007 there were 11000 detectable seismic events and 3000 locatable events, with the largest magnitude of 3.4. The 3.4 event 6 days into stimulation caused non-structural damage leading to mistrust, primarily due to poor communication. Risks of induced seismicity were considered beforehand but information had not reached the authorities or the public and subsequently the authorities stopped the project. Several technologies have learned to cope with induced seismicity, requiring high sensitivity seismic monitoring to distinguish between natural and induced, hence seismic monitoring is a must even where seismicity is not expected. Seismic risk communication is key and monitoring in co-operation with independent institution can aid credibility.

Further discussion highlighted the importance of a strong seismic array to enable distinction between the reservoir and caprock, and questioned the use of a baseline dataset to assist in the separation of natural and induced



CCS pilot, Lacq, France, CO_2 storage into Rousse, Courtesy of Joëlle Hy-Billiot, TOTAL

events reiterating the importance of a dense network to be able to identify the location accurately to pinpoint whether it is associated with operations.

Session 6: Monitoring Performance, Chaired by Ken Hnottavange-Telleen, Schlumberger Carbon Services

To share key outcomes from the 2011 IEAGHG Monitoring Network workshop; held in Potsdam, Germany; Charles Jenkins of CSIRO/CO2CRC presented details of the programme based on EU CCS Directive requirements. Recommendations included: a monitoring and verification plan has to be risk based and should contain 'detection' and 'quantification'; the route to interpretation of 'detection' should be clear in advance and negotiated with regulators and, accuracy levels of techniques have to be understood. Additional points included: the need for cheap surveillance techniques with known sensitivity and risk analyses should guide where to target monitoring.

Ton Wildenborg of TNO presented the results of the EU FR6 CO_2ReMoVe project, which aimed to develop and test technology for predicting, monitoring and verifying geological CO_2 storage; testing procedures and technologies on real projects; demonstrate CO_2 can be stored in a safe and effective way and, develop best practice and guidelines for monitoring and verification. The project has conducted site-specific prediction and verification in the regulatory perspective at Sleipner, Ketzin and In-Salah. CO_2ReMoVe has also investigated Snohvit, K12-B, Kaniow and Weyburn. Geochemical models are integral to assessment, particularly for In-Salah which experienced surface uplift, and 3D-reservoir pressure and geomechanical changes have been modelled, history matching behaviour. Semi analytical modelling combining pore pressurisation and fault pressurisation has also been conducted to investigate the impact of a non-sealing fault on CO_2 plume development around injection well KB-502 by Imperial College, London, but local observations remain a challenge. The project has demonstrated and provided comparison of performance prediction and monitoring.

Anna Korre of Imperial College presented the preliminary results of the IEAGHG study Quantification Techniques for CO_2 Leakage: to identify and review potential methods for quantifying CO_2 leakage from a storage site from the ground or seabed surface as required by the EU ETS and for GHG inventory purposes. Examples of potential methods such as groundwater hydrochemistry and long open path sensing were provided. To quantify CO_2 flux no one technology has been identified and the development of a monitoring portfolio will depend on the specific environment. The study stresses the importance of deep subsurface monitoring to identify potential pathways, locating surface monitoring according to the risk-based monitoring plan and, highlights the importance of detection techniques before the implementation of quantification techniques.

The QUEST project; a joint venture of Shell, Chevron and Marathon to improve the GHG performance of oil sands operations in Canada; uses an iterative

CO_2ReMoVe storage sites, Courtesy of CO_2ReMoVe Consortium Ton Wildenborg, TNO

design process to reduce risks: risk-based, site specific, and adaptive to respond to observed performance with contingency plans in place. Stephen Bourne of Shell presented the fully integrated Saline Aquifer CCS Project. The storage site is within basal Cambrian sandstone with 20% porosity, 50mD permeability and a thickness of 20-40m, with multiple seals: first regionally extensive beyond project boundaries in the middle Cambrian, second a salt complex and the ultimate upper seal is the Lotsberg salt. Monitoring, Mitigation and Verification (MMV) is developing in parallel with regulations. A bow-tie approach has been used to identify risks and safeguards, using a systematic and evidence based evaluation of safeguards and monitoring technologies through collective expert judgement. A suite of monitoring techniques is needed as a diverse program eliminates dependence on a single technology, selected on cost-benefit ranking. MMV contributes to risk acceptance. Implementation of active safeguards e.g. monitoring and corrective measures rapidly decreases the risk metric for broadly acceptance of risk. Discussion highlighted the importance of evidence of absence for communication, for example in the case of verification of no notable change (within a level of uncertainty) on seal pressure gauges; the sharing of information and coordination of best practice between the QUEST project and Goldeneye depleted gas field project offshore Scotland and, on-going public/community engagement process by the QUEST project to allow concerns to be raised and the flexibility to respond.

Session 7: Outcomes and Recommendations, Chaired by Charles Jenkins, CSIRO/CO2CRC and Ameena Camps, IEAGHG

The recurring lessons were identified as:

- A participatory process in pivotal in Risk Assessment, particularly for community assets, and benefits and impacts should be discussed not just numbers.

The objective of the Risk Assessment method is more important than the method itself, though it is important
to note the process use for traceability.

- Monitoring should be risk-based,
- Baseline data is crucial,
- Risk Assessment should be systematic and evidence based using collective judgement.

Drawing from all the sessions, research areas which would benefit from further exploration in future meetings and studies were identified by the members of the RAN. These areas include: further detailed assessment of induced seismicity; further understanding of hydrogeological and geochemical variability and heterogeneity; assessment of remediation/ mitigation techniques; further investigation of microbiological catalysis of geochemical reactions in modelling; a dedicated collation of experiences and knowledge of incident management; a comparative analysis of risk assessment methodological outputs and, a dedicated translation of RAN outputs for laymen/policy makers.
The participants from the 6th meeting of the IEAGHG RAN recommend:

- Methodologies need to be consistent with ISO standard
- There is a need for benchmarking outputs of methodologies
- There is a need for translation of Risk Assessment outputs to common language
- It is important to include community asset value in Risk Assessment
- Further work is required on the evolution of risk through time.

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

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