# ERM - CARBON DIOXIDE CAPTURE AND STORAGE IN THE CLEAN DEVELOPMENT MECHANISM

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# CARBON DIOXIDE CAPTURE AND STORAGE IN THE CLEAN DEVELOPMENT MECHANISM

## POSSIBLE APPROACHES TO CDM METHODOLOGY ISSUES

## Background

In September 2005 project design documents and methodologies for two carbon dioxide capture and storage projects under the Clean Development Mechanism were submitted for approval. The CDM Executive Board were unable to agree how CCS projects should be handled and sought advice from COP/MOP. This initiated a process of wider consultation. The IEA Greenhouse Gas R&D Programme sounded out its members and interested organisations to determine the level of interest in developing CCS projects under the CDM and found it to be sufficient to warrant organizing a workshop. At this first workshop, held in London in April 2006, the main issues which needed to be addressed when formulating a methodology and preparing a Project Design Document for such projects were discussed in order to determine whether a common approach was possible. Several organizations indicated that they were contemplating the possibility of undertaking CCS projects and that in some cases these might be in countries eligible for hosting CDM projects. Furthermore there was a considerable degree of consensus on how the main issues surrounding monitoring and storage site integrity could be handled.

As a result of this consensus Environmental Resources Management was put in charge of documenting theshared view in the form of a set of common guidelines for use by companies when preparing Methodologies and PDD's for CCS projects. The guidelines were circulated to all members of the working group for comment.resulting in this final version.. IEAGHG agreed to publish the report and thus make it available to a wider audience.

## Results and discussion

The guidelines propose in broad terms a common way to address all of the issues surrounding CCS when preparing CDM submissions for CCS projects. The guidelines propose main principles to be followed, particularly when considering the integrity of $CO_2$ geological storage sites and their long term monitoring. The main issues addressed are:

Project boundaries
Baselines
Additionality
Leakage
Project emissions
Permanence
Monitoring

In addition, the report addresses issues and suggestions relating to the overall project approval process, particularly the competencies and expertise that will need to be in place to ensure that high quality CCS projects are implemented under the Clean Development Mechanism.

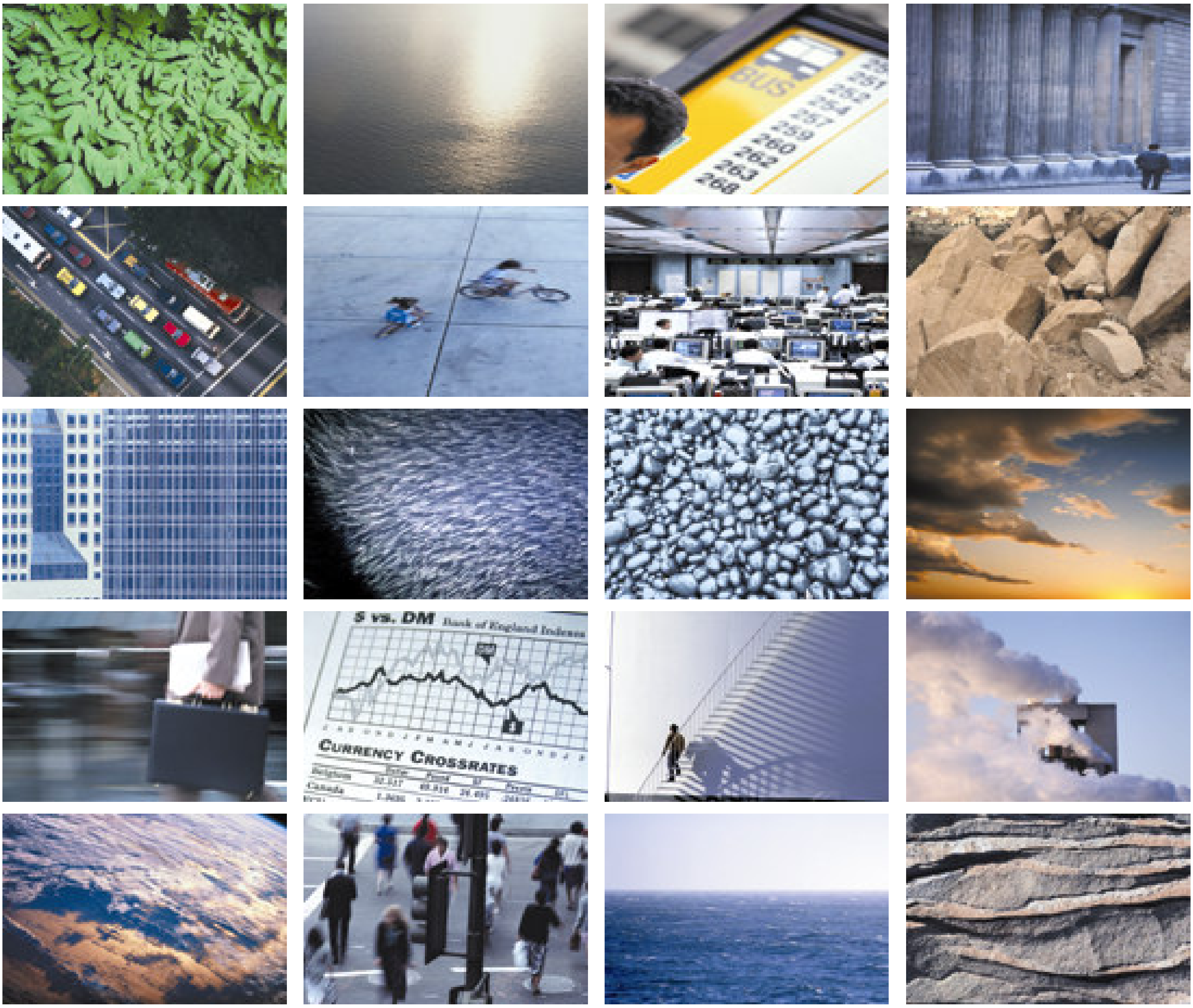
The reader is referred to the full report for further details.

One area that could profit from further consideration and wider consultation relates to CCS projects in which additional hydrocarbons are produced as a result of storing $CO_2$ in oil, gas or coal formations. For dealing with these situations the guidelines explore the option of subjecting CCS projects to an Environmental Impact Assessment (EIA) which would deliver a complete carbon balance encompassing any additional hydrocarbon production associated with the project. The overall environmental impact of such projects as compared to the project baseline and other alternative courses of action could thus be made clear. Such a balance should cover the full lifecycle of the project and could be important evidence as to whether the project enhances the sustainable development of the host country. While this environmental additionality test has some appeal, it is just an option among others to deal with the issue of enhanced hydrocarbon production. Other approaches could be equally viable.

## Conclusions

These guidelines should be of assistance to organisations contemplating submitting CCS projects under the Clean Development Mechanism. Following their general principles should ensure development of a consistent set of CDM methodologies for this type of project and also promote their quality and integrity.

At the present time the way in which CCS projects could be included within the CDM is still under review. It is planned to reach a decision at COP/MOP4 in December 2008 following a process of further consultations with organisations and Parties. However, in parallel with this process submission of more methodologies for CCS projects was encouraged by COP/MOP2 and these guidelines are offered as assistance to any organisation undertaking this task. .




# Carbon Dioxide Capture and Storage in the Clean Development Mechanism

Possible Approaches to CDM Methodology Issues

April 2007

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International Energy Agency Greenhouse Gas Research and Development Programme (IEA GHG R&D Programme)

# Carbon Dioxide Capture and Storage in the Clean Development Mechanism: *Resolving CDM Methodology Issues*

April 2007

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Date: 4th April 2007

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## *EXECUTIVE SUMMARY*

### *Background*

This report explores the issues associated with designing an accounting methodology relevant to carbon dioxide ($CO_2$) capture and geological storage (CCS) operations as a Clean Development Mechanism (CDM) project activity.

It has been prepared by *Environmental Resources Management Ltd*. (ERM) over the period May-October 2006, working in a process initiated by ERM, *Shell*, *Det Norske Veritas*, *Statoil* and the *IEA Greenhouse Gas R&D Programme* (IEA GHG). Its development has also involved a wide range of other stakeholders, including various participants at in the SBSTA24 meeting, and IEA GHG workshops on the subject held in London and Vienna.

Its findings should not be considered as a definitive set of conclusions on the matter, but rather an outline of the most advanced thinking on the subject by an expert group at the time of writing. A brief review of the report contents is provided below.

### *Title and applicability*

$CO_2$ can be captured from a range of anthropogenic sources, transported and stored in a variety of sub-surface geological media. Although CCS can apply to spectrum of operations, from an accounting perspective there are commonalities to the different CCS applications at a systems level. Consequently, the report suggests that a single 'modularised' CDM accounting methodology may be appropriate for CCS in the CDM, as opposed to the development of myriad approaches. Suggestions are made with regards to the methodology title and applicability criteria.

### *Project boundaries*

Project boundaries for a CCS CDM project activity should encompass the full chain of operations taking place, including capture at a power plant or industrial installation generating $CO_2$, its transport, injection and long-term storage in subsurface geological formations. The subsurface boundary should cover not only to the lateral and vertical edges of the plume of inject $CO_2$, but also extend to the zones surrounding the plume where migration or seepage of $CO_2$ could occur. Whilst a number of legal and sovereignty issues are potentially posed by CCS operations, from a CDM accounting perspective few new issues are posed by CCS project boundaries.

### *Baselines*

Whilst the baseline scenario for a CCS project might be considered straightforward (i.e. the same project without $CO_2$ capture), some complexities do arise when considering new build plants or major retrofits. Where $CO_2$ capture is an integral part of the process design (e.g. new-build or major retrofit), it can significantly alter overall system configuration from a standard plant. Consequently, $CO_2$ captured should not be considered to be the same as $CO_2$ avoided. The baseline for a CCS project must be calculated based on $CO_2$ avoided, which can in some cases be $CO_2$ captured, but not in others. The report highlights a range of potential baseline scenarios, and proposes methods by which the baseline may be calculated for each.

***Additionality***

Additionality for CCS projects does not present new issues in the CDM, as there are few circumstances under which injection of $CO_2$ into the subsurface is economically attractive in the absence of a carbon value. Such situations might include incidental injection as part of a mandatory acid-gas disposal activity, or injection for enhanced hydrocarbon recovery (EHR). Evaluation of project alternatives and assessment of financial additionality, barriers test and common practice analysis can all be applied to assess the additionality of CCS CDM project activities. The report also proposes the option of an *environmental additionality* test in CCS projects to account for the long-term nature of some CCS activities and the difficulty in attributing certain emissions to a specific project (e.g. as in enhanced oil recovery; EOR). The environmental additionality proposal involves the calculation of a full *ex ante* carbon balance across the whole project life-cycle, and the requirement to demonstrate that the project delivers greater emission reductions over its whole life than the *ex ante* estimate of CERs to be created by the project.

***Leakage***

Leakage can occur in CCS projects, although most of the potential sources of leakage emissions identified in the report have all been considered before in the CDM (e.g. biomass use, increasing electricity consumption etc.). EHR does have some similarities with coal bed methane recovery; however, for EOR which is delivering oil into international markets, new issues are presented. Typically, it will be exceedingly difficult to trace and attribute specific emissions associated with any incremental oil produced in an EOR project. Consequently, it is proposed that EOR projects could be subject to the *environmental additionality* test outlined above as one possible alternative option to recognise this issue.

***Project emissions***

A range of potential sources of project emissions are highlighted and described, including fugitive emissions, combustion emissions, and seepage emissions from the storage reservoir. Only the seepage emissions present new issues for consideration in CDM accounting methodologies.

***Permanence***

The range of options for handling permanence in CCS projects is reviewed, and it is concluded that CERs from CCS projects should be equivalent to other CER commodities. The basis for this conclusion is that seepage is not an inherent part of any CCS project, but rather a function of good site selection, risk management, and appropriate site closure. Thus, effective management of permanence should be through project approvals which are robust enough to consider these items, not through creation of new mechanisms. Some thoughts on financial mechanisms for handling risks are also discussed.

***Monitoring methodology***

The above ground elements for a CCS project activity do not present any new considerations in the context of a CDM monitoring methodology, and are not considered in depth. The sub-surface element(s) do present new issues for consideration, which forms the focus of this Section. Building on the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 5, a step-wise procedure for the design of a sub-surface monitoring plan is elaborated. Instead of proposing a prescriptive approach, the scheme outlined suggests a 5-step approach for scheme design, followed by a further 6-step plan for the operational phase. For each step, a quality assurance and quality control procedure is suggested. The step-wise approach is designed so that a project proponent arrives at a monitoring scheme (technology types, locations, frequency of application) specific to any proposed storage site. As a minimum, project proponents should consider the full range of monitoring technologies contained in Annex I of Volume 2, Chapter 5 of the IPCC 2006 guidelines, and justify the selection (or not) of the different technologies reviewed.

***Project approvals***

Project approval will be a critical step in ensuring the deployment of high quality CCS projects, including determination of appropriate responsibilities and liabilities associated with the project. Key to the process will be the undertaking of a full risk-based environmental impact assessment, which is subject to scrutiny by host country regulators and the designated operational entity (DOE). Recognising that regulators in some host countries may not have expertise in CCS operations, it is suggested that a roster of experts and other support and capacity building mechanisms be introduced for CCS projects in the CDM. In addition, the role of the DOE is discussed, and the report proposes that they can play a key role in project approvals. As such, a new CDM sectoral scope for CCS will be needed, and that accreditation to this scope by DOEs must also be achieved. Suggestions are made as to which bodies could assist in defining the certification standard for DOEs to this scope.

# 1 INTRODUCTION

This report explores the issues associated with designing an accounting methodology relevant to CCS operations as a CDM project activity.

It has been prepared by *Environmental Resources Management* (ERM), a consultancy firm with significant expertise in both carbon dioxide ($CO_2$) capture and geological storage (CCS) (1) technologies, policy and regulations and also the Clean Development Mechanism (CDM) process. It has been prepared over the period May-October 2006.

Whilst the report has been prepared by ERM, its development was initiated alongside *Shell*, the *IEA Greenhouse Gas R&D Programme* (IEA GHG), *Det Norkse Veritas* and *Statoil*, and has evolved through a stakeholder approach involving inputs, views, and technical expertise from a broad number of individuals and organisations, including *inter alia*:

- Expertise in-kind provided by *Shell* staff covering all aspects of CCS operations (above-ground capture, process engineering, and expertise in sub-surface engineering);
- IEA GHG expertise on CCS technologies and monitoring techniques;
- *Det Norske Veritas* which has considerable expertise in both CCS and CDM, and as a CDM Designated Operational Entity (DOE) has provided a 'pre-validator' thoughts on the approach outlined;
- Support from *Statoil ASA* a company who operates the Sleipner CCS project in the North Sea, and is also a partner on the In Salah CCS project in Algeria;
- Other parties and stakeholders involved with the IEA GHG workshops on CCS and CDM held in London (19-20th April 2006) and Vienna (7th August 2006). A range of views and perspectives were provided at these workshops and the underlying principles for the work outlined herein have been influenced by this stakeholder group;
- Submissions from Parties and Observer organisations to the UNFCCC Secretariat, and presentations at the SBSTA24 workshop on CCS in the CDM; and,
- Other industry, academia and policy-maker perspectives.

A multi-stakeholder approach was initiated such that a common view on CCS CDM accounting methodologies could be reached in a transparent manner using expert input from across industry, academia and government.

The analysis and discussion presented is designed to further the debate regarding various aspects of CDM accounting for CCS, in particular project boundaries, leakage, baselines, permanence and monitoring methods. The reader should not consider the findings to be a definitive set of conclusions on the matter, but rather an outline of the most advanced thinking on the subject

(1) Oceanic $CO_2$ storage in the water column is not considered because of the greater scientific uncertainty about the safety of this activity. This report only considers geological $CO_2$ storage.

by an expert group at the time of writing. Thoughts and further discussion on any of the subjects raised are welcomed.

Prior to setting out the key issues, a brief synopsis of the development of CCS issues in the CDM to date is provided in the next *Section*.

## 1.1 *CCS IN THE CDM TO DATE*

### 1.1.1 *Project activities*

Two CCS CDM projects with associated Project Design Documents (PDDs) and proposed new methodologies (1) were submitted to the CDM Executive Board (CDM EB) in late 2005 and early 2006. The two proposed projects are:

- *September 2005*. The "White Tiger" project involving the capture of $CO_2$ from gas-fired power plants and its transport offshore for use for enhanced oil recovery (EOR) purposes in a mature oil field. This included the proposed CDM baseline (NMB) and monitoring (NMM) methodology NM0167; and,
- *January 2006*. The "Bintalu LNG" project involving the co-injection of $CO_2$ and $H_2S$ into a saline formation in offshore East Malaysia (Sarawak), including a proposed NMB and NMM in NM0168.

A number of other CCS CDM projects are also under consideration by a range of actors (2).

### 1.1.2 *Response by the CDM EB and COP/MOP*

Following the submission of the "White Tiger" PDD, the CDM Executive Board (EB) considered CCS projects as CDM project activities at its 22nd meeting (November 2005), but was unable to agree on how CCS projects should be handled. Consequently, the EB requested the COP/MOP to provide guidance on whether CCS can be considered as a CDM project activity, taking into account issues related to project boundary, leakage and permanence.

In response, the COP/MOP invited Parties to provide submissions to the UNFCCC Secretariat in relation to these issues by 13th February 2005 (3). A range of Parties and observer organisations submitted views, including several Parties to the UNFCCC, IPEICA and the *International Emissions Trading Association* (IETA).

In addition, the COP/MOP requested the *Subsidiary Body on Scientific and Technical Advice* (SBSTA) to hold a workshop on CCS and an additional

(1) Note: At the 24th Meeting of the CDM EB (10-12 May 2006) a new methodology form (NM) was introduced which covers both the baseline and monitoring methodology. This replaced the old new methodology baseline (NMB) and new methodology monitoring (NMM) forms.
(2) As evidenced through discussion with a range of organisations present at the IEA GHG R&D workshop on CCS as a CDM project activity.
(3) Decision CMP.1/21
(http://unfccc.int/files/meetings/cop_11/application/pdf/cmp1_24_4_further_guidance_to_the_cdm_eb_cmp_4.pdf)

workshop specific to CCS in the CDM at its 24th Meeting in May 2006, and report findings to the COP/MOP2 Meeting in November 2006.

### 1.1.3 *Recommendations from the CDM Methodologies Panel*

In addition to the activities outlined above, the CDM Methodologies Panel (CDM Meth Panel) – reporting to the CDM EB – outlined its recommendations following its 21st Meeting (21st June 2006). In its report, the CDM Meth Panel outlined a number of general issues to be resolved for CCS CDM project activities going forward, including:

- *Policy and legal issues*. Concerns raised are largely associated with items such as acceptable leakage rates, risk, uncertainty, liability, project boundary issues, long-term responsibility, remediation, and accounting options for dealing with long-term seepage (1); and,
- *Technical / methodological issues*. These relate to guidance for storage site selection, sub-surface monitoring techniques, and reservoir operations such as drilling, well-sealing and abandonment etc.

The CDM Meth Panel report also highlights a range of general CDM methodological issues including:

- *Physical leakage (seepage) from storage sites*, covering: Site selection criteria, monitoring methods for seepage emissions, acceptable levels of seepage, and a range of other key questions for consideration going forward.
- *Permanence and liability*, covering: seepage emissions during the crediting period, seepage emissions after the end of the last crediting period, and key questions for consideration going forward.
- *Project boundary*, covering: trans-boundary issues, inventory allocations and DNA authority, and joint storage from multiple projects.

This analysis has now been formalised into detailed report of the methodologies CCS received to date, as outlined in the report of the 22nd meeting of the Meth Panel. This report concludes that the proposed methodologies do not 'adequately or appropriately' address the key methodological issues posed by CCS in the CDM in their current format, and call for a number of items to be prepared, including a step-wise process for designing a monitoring methodology. Furthermore, the CDM EB has taken these findings and drawn the same conclusions (see the report of the 26th Meeting of the CDM EB).

## 1.2 *REPORT STRUCTURE AND APPROACH*

Based on the issues and developments outlined, the authors of this report – alongside the stakeholders described previously – considered it appropriate to set about addressing many of the questions raised, drawing on expertise within the relevant organisations. The report is focussed on the general issues

(1) In this report the term seepage is used to refer to physical leakage of CO2 from sub-surface geological storage formations.

associated with CCS projects relevant to the design of a CDM methodology. The major themes explored are:

- *Section 2*: CCS applications and applicability criteria;
- *Section 3*: Project boundaries for CCS projects.
- *Section 4*: Baselines relevant to CCS projects.
- *Section 5*: Additionality issues.
- *Section 6*: Project emissions across the project.
- *Section 7*: Leakage issues.
- *Section 8*: Permanence issues.
- *Section 9*: Monitoring methods.
- *Section 10*: Project approvals

This structure allows the technical issues raised by CCS projects to be reviewed, and the rationale for the selection of different methodological choices to be highlighted.

A series of Annexes are also included covering:

- *Annex A*: Technologies and applications for CCS.
- *Annex B*: CDM precedents for baseline issues.
- *Annex C*: CDM precedents for leakage issues.
- *Annex D*: Submitted CCS monitoring methodologies.

# 2 METHODOLOGY TITLE AND APPLICABILITY CRITERIA

## 2.1 BACKGROUND

A new methodology requires the proponent to outline the title and conditions under which the new methodology can be applied.

In this context, a range of CCS technologies and applications are reviewed in *Annex A*. This review highlights the circumstances and situations under which CCS could be applied. This review is the basis for the methodology title and applicability criteria outlined below.

An overview of CCS is also provided in *Box 2.1*.

***Box 2.1 Overview of CCS technologies***

CCS is a process consisting of the separation of $CO_2$ from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere.

CCS is considered as an option in the portfolio of mitigation actions for stabilisation of atmospheric greenhouse gas (GHG) concentrations. The Intergovernmental Panel on Climate Change (IPCC) in its Special Report on CCS (SRCCS) (1) concluded that:

*Available evidence suggests that, worldwide, it is likely there is a technical potential of at least about 2,000 $GtCO_2$ of storage capacity in geological formations. In most scenarios for stabilization of atmospheric GHG concentrations between 450 and 750 ppmv $CO_2$…CCS contributes 15-55% to the cumulative mitigation effort worldwide until 2100.*

The IPCC also conclude that:

*With appropriate site selection based on available sub-surface information, a monitoring program to detect problems, a regulatory system and the appropriate use of remediation methods to stop or control $CO_2$ releases if they arise, the local health, safety and environment risks of geological storage would be comparable to the risks of current activities such as natural gas storage, enhanced oil recovery and deep underground disposal of acid gas.*

*Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and likely to exceed 99% over 1,000 years.*

As such, CCS technologies should be considered as a key tool in the portfolio of climate change mitigation technologies available in the first part of the 21st century.

In terms of the CDM, it seems feasible that that CCS can be considered as a CDM project activity given that avoided $CO_2$ emissions from CCS projects are real, measurable and long-term, and that the $CO_2$ emissions avoided from CCS projects are, by definition, emissions that would have occurred otherwise in the absence of the CCS project activity.

## 2.2 APPROACHES TO DEFINING APPLICABILITY CRITERIA

Given the range of sources and installation types to which CCS could be applied, the different options for transport, and the scope for storing $CO_2$ in different geological media (See *Annex A*), there exists two approaches to developing a methodology relevant to inclusion of CCS in the CDM:

(1) IPCC 2006 Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press.

- Either develop a number of separate methodologies applicable to different specific project types; or,
- Develop a range of applicability criteria in a methodology – a sort of modularised approach – in order to ensure wide coverage of the methodology.

In this study, the point of departure has been the latter i.e. to try and define issues with respect to a single methodology with wide applicability criteria. This approach has been adopted due to fact that, whilst a potential wide range of technologies and sources of $CO_2$ for exist relevant to CCS, in fact the underlying system principles are common to a range of applications.

Based on this approach, proposed wording for a methodology title and applicability criteria are outlined below.

## 2.3 *PROPOSED METHODOLOGY TITLE AND APPLICABILITY CONDITIONS*

A proposed methodology title for application to the full range of CCS projects reviewed above is as follows:

**Methodology Title**

Capture of $CO_2$ from power generating plant(s) or industrial installation(s), transport via pipeline, and long-term storage in geological formations.

Such a description includes coverage of all potential fuel types, relevant industrial processes and capture transport and storage techniques, as well as projects undertaken with or without enhanced hydrocarbon recovery.

**Applicability**

The proposed methodology is applicable to $CO_2$ capture and storage project under the following conditions:

- This methodology applies to new build power generation plants combusting fossil fuels or biomass and other industrial installations generating $CO_2$ emissions and employing any $CO_2$ capture process; and, retrofitted power generation plants combusting fossil fuels or biomass and other industrial installations generating $CO_2$ emissions and employing any $CO_2$ capture process.
- This methodology applies to $CO_2$ captured and transported to storage sites via pipeline and tankers (e.g. marine vessels or road or rail tankers).
- This methodology applies to $CO_2$ storage in well-selected, designed and managed geological storage sites, including saline formations, depleted oil & gas reservoirs, or deep coal seams.
- This methodology applies to projects utilising $CO_2$ for enhanced hydrocarbon recovery, including but not limited to the following activities:
  - enhance oil recovery (EOR)
  - enhanced gas recovery (EGR)
  - enhanced coal bed methane (ECBM)

- This methodology is not applicable to projects capturing $CO_2$ and transferring it for uses other than geological storage.

The issues explored in the remainder of this report are based on projects meeting these criteria.

# 3 PROJECT BOUNDARY

## 3.1 BACKGROUND

Under the Marrakesh Accords (1) a CDM project boundary…

> *…shall encompass all anthropogenic emissions by sources of greenhouse gases (GHG) under the control of the project participants that are significant and reasonably attributable to the CDM project activity.*

Project boundary has been highlighted as a key issue for CCS projects in the CDM by a number of observers, including the CDM EB, CDM Meth Panel and several Parties inputting into the SBSTA24 workshop.

The major concerns raised can be broadly split into two issues:

- CDM-specific methodological issues, and;
- Other general legal/regulatory issues.

These are reviewed in greater depth as follows.

## 3.2 METHODOLOGICAL ISSUES

A CDM project boundary is a difficult proposition to define, as the definition offered by the Marrakech Accords provides for considerable ambiguity. For example:

- Is it defined by the project participants? CCS project could involve multiple sources and storage sites, thus requiring many project participants. In such cases, do all operators need to be project participants?
- Is it also defined by the emissions sources? For a CCS project the storage site is only a *potential* emission sources, so should it be inside the project boundary?
- Is there a temporal aspect to the definition of project boundary? In CCS projects, emissions could occur after the crediting period due to seepage of $CO_2$ from the storage site, and they could still be under the project participant's control. Should these be considered as leakage (see *Section 6* below)?

Notwithstanding such ambiguities, the purpose of this report is not to consider the legal interpretations of Marrakesh Accords with regards to project boundaries, but rather discuss them in the context of CCS activities. As such, the working assumptions adopted in preparing this report are:

(1) Decision 17 CP.7 , Annex, Article 52 which define the modalities and procedures for a clean development mechanism

- That in any CCS CDM project, operators across all parts of the CCS chain could be project participants, although there may be other permutations for project ownership depending on specific circumstances.
- That all sources of $CO_2$ across the whole CCS chain be considered to be within the project boundary, including the *potential* emissions from the storage site (see *Section 3*).
- The definition is that of a spatial boundary.

Based on this interpretation, there are a number of emission sources associated with a CCS CDM project activity that could be considered as within the project boundary including:

- *Fugitive emissions*: resulting from items such as imperfect capture at the source, emissions from solvent stripping operations, $CO_2$ transport pipeline leaks and maintenance activities, operational and emergency venting; losses during injection etc.;
- *Indirect emissions*: resulting from the use of bought-in electrical energy required for the project e.g. at pipeline booster stations;
- *Seepage emissions*: gradual emergence of small quantities of $CO_2$ to the surface – detected by site monitoring - which do not constitute site failure but must be debited against the quantity of $CO_2$ stored in the site;
- *Storage site breach*: arising as a result of major containment failure of the $CO_2$ storage site and emergence of $CO_2$ into the atmosphere (highly unlikely if site selection and permitting review have been done correctly) – in this instance the CDM project would be deemed non-operational and any past credits awarded would be void since amounts stored for past credit have now re-entered the atmosphere.

Consequently, all of these emissions will need to be monitored and accounted for in a CCS CDM project activity. However, on the whole these should not present any new considerations in the context of the CDM, with the exception of seepage emissions or storage site breach (1).

Important components that can be considered to be within the project boundary include:

- Above ground installations;
- Well(s);
- Sub-surface storage formation(s) or "storage complex" (2);
- Zones surrounding the sub-surface storage formation(s) where the areal extent and "separation distance" takes into account other users' activities e.g.:

(1) These types of emissions sources present new complications in the context of the CDM. Principally this relates to the temporal disjoint between when the emissions are originally mitigated, and when they might occur in the future.
(2) The report uses the term "storage complex" to introduce a concept of a safe-storage container which is analogous to an engineered storage system such as a tank farm. In a tank farm, there is a primary vessel and primary seal (the tank & tank walls), there is also a secondary containment system comprising a concrete apron and bund-wall, there may be subsequent aprons & barriers & controlling drainage systems. These secondary & tertiary systems are safety features designed in such a way that seepage from primary containment does not lead to emissions to sensitive domains but does allow for management choices and changes to the filling mechanism. In the subsurface, a primary injection zone & primary top-seal might have several overlying reservoir-seal pairs within the brine geosphere. Seepage of $CO_2$ into these does not constitute loss of containment, but does provide considerable operating safety margin.

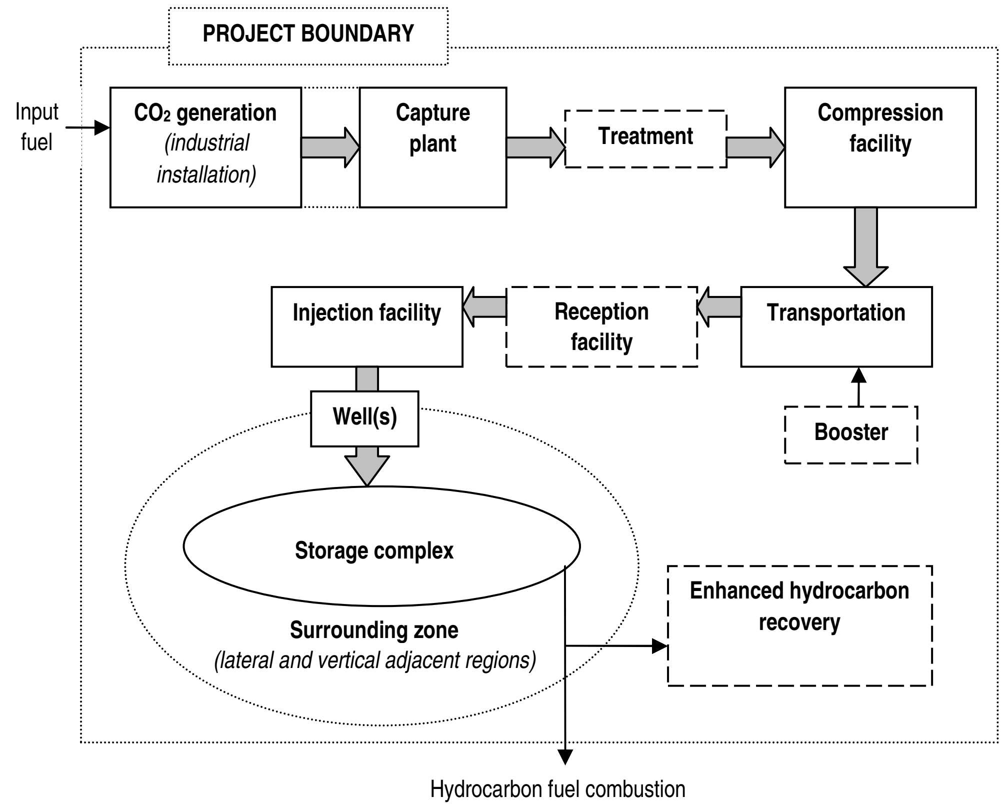
- Oil & gas fields
- Deep mines
- Activities in the "hydrosphere" such as
  - Gravel extraction;
  - Potable/agricultural water extraction;
  - Land-fill etc;

- Emissions associated with enhanced hydrocarbon recovery using $CO_2$ ($CO_2$-EHR). (*Figure 3.1*)

Each of these items is reviewed in greater detail below.

It is important to also note that the definition of a CDM project boundary is generally interpreted to refer to a *spatial* boundary, not a *temporal* boundary, which is a key distinction when considering permanence and the definition of leakage. This issue is considered further in *Sections 6* and *8*.

***Figure 3.1*** ***Components of a CCS project within the CDM boundary***




Note: Boxes with broken lines represent items that may not be common to all CCS projects

### 3.2.1 *Above ground installations*

The project boundary should encompass all components in the CCS chain of operations occurring above ground, including the industrial installation where the $CO_2$ is generated (e.g. a power plant or synfuel plant), the capture plant, any additional $CO_2$ treatment facilities (e.g. sulphur removal plant; dehydration facilities), the compression facility, the transportation equipment (pipeline or tanker), any booster stations along a pipeline (1), any reception facilities or holding tanks at the injection site, and the injection facility.

These items present similar technical elements of any typical CDM project, and as such emissions from these components can be calculated based on monitoring techniques and approaches applied in other CDM project activities.

It is important to note that in some complex industrial installations (e.g. chemical plants; synfuel production, LNG plants, refineries) there are often multiple $CO_2$ sources arising from a number of different combustion plants or processes (2), not of all of which may be part of the CCS scheme. Typically, this will occur where $CO_2$ capture at smaller combustion plant is not considered economically attractive, and are therefore omitted from the CCS project. In such situations, it may be beneficial to consider such units outside of the project boundaries for the purpose of reducing monitoring requirements.

### 3.2.2 *Well(s) and other "bridges"*

Injection, observation and any other abandoned wells form a bridge between the above ground components of a CCS project, and the sub-surface storage complex. Other bridges might include mine shafts, boreholes etc. which will also need to be considered. Well bore failure and or seepage of $CO_2$ from well casings and other bridges must be considered as one of the weakest point in the overall containment system, and as such do present a potential source of emissions. Consequently, observation wells, abandoned wells, injection wells and any other bridges must be considered to be within the CDM project boundary and monitored for emissions accordingly. Well-monitoring will also be required during and beyond the crediting period for health, safety and environmental reasons. This issue is covered is greater detail *Section 9* where the CCS CDM monitoring methodology is considered.

### 3.2.3 *Sub-surface storage complex*

The sub-surface storage formation(s) that make up the storage complex, and the plume of injected $CO_2$ in the complex must be considered to be within a project boundary for any CCS CDM project activity.

The project boundary of the subsurface storage complex must be defined by site characterisation and storage performance assessment studies carried out as part of a feasibility study in advance of commencing $CO_2$ injection operations. This will generally be in the form of calibrated and tested static and dynamic sub-surface geological Earth model(s) which are able to define the vertical and lateral extent of the primary formation(s) and the maximum spatial extent of fluid migration (3), and subsequently the project boundary, taking into account the total planned amount of $CO_2$ to be stored.

(1) Including any bought-in gas or electricity used to run the booster facility.

(2) In AM0029, such smaller combustion plant and operations are referred to as *elemental processes*.

(3) In synclinal systems this might be determined by the predicted extent of plume migration through the storage complex, including a safety margin of error in the modelling.

The definition of the project boundary for this component will be dependent on two key factors contained in the static and dynamic geological Earth model(s):

i) The geological, stratigraphic, geomechanical, and geochemical characteristics of the reservoir–seal complex into which $CO_2$ is to be injected, and project specific engineering factors, including:
    - The nature of the $CO_2$ trapping mechanism(s) including structural/physical trapping, mineral trapping, solubility trapping, ionic trapping, residual trapping and the rate at which these processes might occur;
    - Caprock integrity;
    - Lateral sealing;
    - Formation(s) permeability and $CO_2$ migration rate;
    - Formation(s) geological homogeneity/heterogeneity;
    - $CO_2$ delivery and injection rate and total anticipated mass/volume;
    - Phase state of the $CO_2$ in the formation(s) (actual and simulated, which depends on a variety of factors such as depth, pressure and temperature); and,

ii) The quality the sub-surface evaluation process including the data available on these factors and the quality of the computer software which is used to build the subsurface simulation models of the storage formation(s).

When sufficient data has been collected and sufficient simulations undertaken using appropriate geological Earth modelling techniques, a reasonable description of the subsurface target '$CO_2$ containment complex' and its associated uncertainties can be made. This process, together with information about other sub-surface users and uses, must be considered to be the fundamental basis for defining the project boundary for the subsurface component of a CDM CCS project activity (1).

Inherently, by using such an approach to define the project boundary suggests that any deviation of such behaviour could be considered as seepage (2) i.e. migration of $CO_2$ outside of the defined target containment complex. Such an interpretation is perhaps not prudent, and seepage should be defined by potential negative effects of migration, rather than deviation from predicted behaviour. Further discussion of this subject is provided in *Section 9*, where issues associated with developing a CCS CDM monitoring methodology is reviewed.

Subsequent to defining the primary $CO_2$ containment complex, as outlined above, ongoing monitoring of the formations and $CO_2$ plume will be necessary in order to:

(1) However, notwithstanding even the most rigorous of analysis, modelling will only provide a simulated picture of the subsurface plume, and in reality deviations from the predicted behaviour can be expected.
(2) Seepage is the term used in this report to refer to physical leakage from $CO_2$ storage sites.

- Gather data on the subsurface plume behaviour in order to verify the permanence of storage of the $CO_2$ in the target formations; and,
- History-match observations with projected behaviour of the $CO_2$ undertaken as part of the initial site characterisation and storage performance assessment. Results can be used to re-calibrate and refine previous model runs, and also assist in identifying any seepage from the target formation(s) (1).

Monitoring of the target formation(s) itself will be useful for assessing permanence of storage, but may not be sufficient to detect seepage from the reservoir, and monitoring of the area surrounding the proposed primary $CO_2$ containment complex will be likely required in order to provide early detection of seepage.

### *3.2.4 Zone surrounding the sub-surface storage formation(s)*

The zone surrounding the defined primary $CO_2$ containment complex must also be considered as a component within a CCS CDM project boundary. It will be this zone where any seepage – or migration - from the proposed primary $CO_2$ containment complex will occur, and as such must be monitored for evidence of migration. However, it is important to note that through careful site selection and containment assessment, such primary "seepage" or migration will likely not lead to emissions of $CO_2$ back to the atmosphere.

Application of continuous and intermittent monitoring techniques in the area around the primary containment complex will be a key part of a CCS project in order to:

- Identify zones around the primary $CO_2$ containment complex which may present the potential risk of seepage of $CO_2$ i.e. a full assessment on potential $CO_2$ "bridges" back the surface and/or other vulnerable media;
- Estimate emissions associated with any seepage of $CO_2$ back to the atmosphere for CDM accounting purposes, as well as allocation of seepage emissions into a country's national GHG inventory. This will form part of the project emissions attributable to the project within the CDM crediting period, as well as for the purpose of managing residual liabilities for any seepage associated with the project after the end of the crediting period; and,
- Monitor and manage the potential localised environmental, health and safety impacts posed by seepage from the storage formation(s) (or from injection well failures), either back the surface or into any adjoining environmental media such as groundwater or soil.

As such, in defining the primary $CO_2$ containment complex, an appropriate monitoring plan will also be determined, designed around specific attributes associated with the specific planned storage site, and based on a risk-based modelling exercise. Key monitoring locations around the primary containment complex might include:

(1) An adaptive learning process whereby greater knowledge of the sub-surface is gained through monitoring, and models are updated to reflect the knowledge gained.

- The caprock(s);
- Spill points at the lateral edges of a geological structural trap;
- Up and down dip at the predicted lateral edges of the primary containment complex;
- Potential pathways for seepage including:
    - Any new or abandoned wells in the storage and surrounding zone;
    - Any geological faults in the system in the proximity of the containment complex;
    - Sub-surface and surface zones where more permeable layers in the overburden interface with the vadose zone (based on regional geology and stratigraphy) in order to take account of potential migration through and seepage from these rocks.
- Potential receptors for any seeped $CO_2$, including:
    - Overlying primary aquifers/reservoir formations still within the brine geosphere;
    - Soil gas;
    - Groundwater and surface springs;
    - Terrestrial and freshwater flora and [micro] fauna;
    - Benthic sediments;
    - Benthic waters;
    - Marine flora and [micro] fauna.
- Application of airborne (aeroplane; satellite) remote sensing techniques able to cover broad swathes of land.

These issues are covered in the greater detail in the context of designing a CDM monitoring methodology in *Section 9* of this report.

### *3.2.5 Enhanced hydrocarbon recovery*

In $CO_2$-EHR (enhanced oil, gas or coalbed methane recovery) operations using anthropogenic $CO_2$ which propose to also operate as CCS projects, several new sources of project emissions are created, including:

- Breakthrough of injected anthropogenic $CO_2$ at extraction wells;
- Emergence of natural reservoir $CO_2$ and/or $CH_4$;
- Additional energy use for hydrocarbon recovery;
- Additional energy use for $CO_2$ stripping and recycling;
- Flare or venting emissions.

Emissions from these sources must be considered within the project boundary of a CDM project activity.

Further analysis of accounting issues for $CO_2$-EHR operations is provided in preceding sections covering baselines, additionality, leakage and project emissions (*Sections 4, 5, 6* and *7*).

### 3.3 *2006 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES*

Volume 2 Chapter 5 of the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (the 2006 GHG guidelines) outlines accounting procedures for GHG emissions from geological $CO_2$ storage sites. Due to the scarcity of actual monitored data from storage sites upon which to develop empirical emissions factors for $CO_2$ storage sites, the proposed accounting approach adopts a Tier 3 methodology.

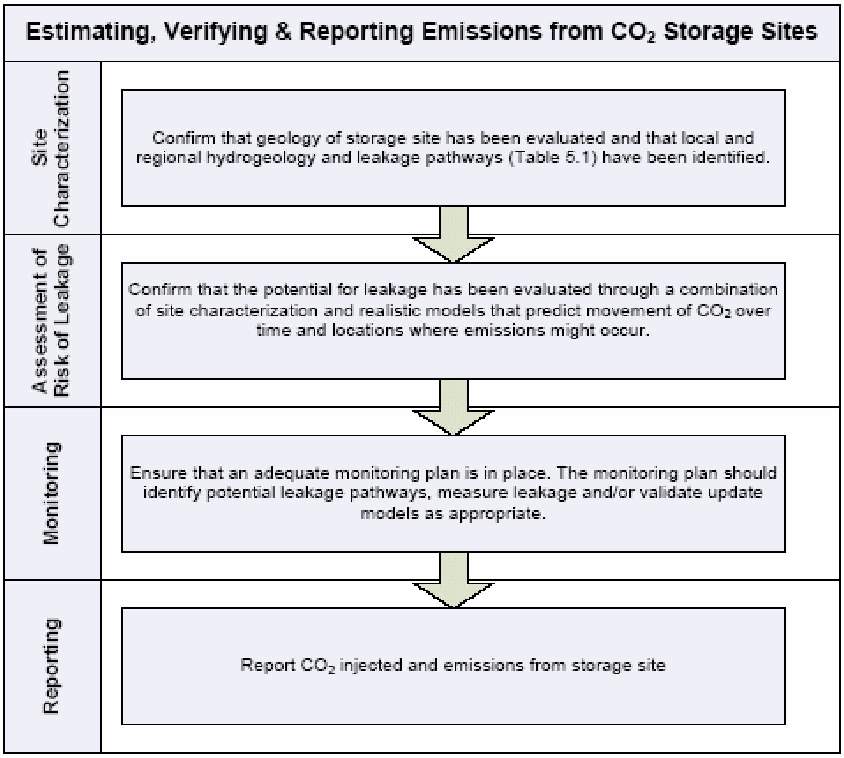
The Tier 3 methodology requires specific monitoring of each project to determine site specific $CO_2$ emissions for any geological storage site. As such, this sets an important precedent for determining the accounting and monitoring methodology for $CO_2$ storage sites in the CDM.

The 2006 GHG guidelines also include accounting methodologies for $CO_2$ pipelines, which can be employed within a CDM methodology.

#### 3.3.1 *GHG accounting methodology for $CO_2$ storage sites*

Within the 2006 GHG Guidelines, a schematic is presented outlining the monitoring procedure for determining storage site emissions (*Figure 3.2*).

***Figure 3.2 Monitoring procedure - 2006 IPCC GHG guidelines***




Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 5

The process outlined involves the development of an assurance-based scheme to demonstrate good storage site selection, evaluation of risks of containment loss, demonstration of a bespoke (or "adequate") monitoring plan, adaptive learning principles, and monitoring and reporting. As such, it creates a *de* *facto* approvals process for appropriate $CO_2$ storage site selection, risk assessment, and monitoring design.

The 2006 GHG Guidelines provide further details on the series of methodological steps that need to be undertaken in to compiling the inventory, including:

1. Identify and document all geological storage operations in the jurisdiction
2. Determine whether an adequate geological site characterization report has been produced for each storage site, including:
    a. Identify and characterise potential seepage pathways such as faults and pre-existing wells
    b. Quantify the hydrogeological properties of the storage system
    c. Include enough data to compile a geological Earth model of the site and surrounding zone
3. Determine whether the operator has assessed the potential for leakage at the storage site, including:
    a. Including likely timing and flux of any fugitive emissions
    b. Demonstration that seepage is not expected
    c. Short-term simulations to predict site behaviour during and beyond the injection (decades)
    d. Long-term simulations to predict the fate of $CO_2$ over centuries to millennia
    e. Sensitivity analysis
    f. Design of the monitoring programme
    g. Update with new data and operational changes
4. Determine whether each site has a suitable monitoring plan (1).
5. Collect and verify annual emissions from each site [and perform history matching].

### 3.3.2 *Relevance of the 2006 Guidelines to CDM*

The scheme presented above for defining the CDM project boundary for the sub-surface component for a CCS project activity is considered to be consistent with the 2006 GHG Guidelines, based on the following:

- *Step 2*: This is consistent with the design of the static Earth model described in *Section 3.2.3*;
- *Step 3*: This is consistent with the dynamic modelling process described in *Section 3.2.4*.
- *Step 4*: This is considered further in *Section 9*, where the design of the CDM methodology for defining the sub-surface monitoring plan is discussed.

As the 2006 GHG Guidelines form the basis for Annex I country reporting of GHG emissions in national inventories, then the process should be considered as appropriate for application in a CDM methodology.

(1) Including, presumably, *a priori* demonstration through forward modelling of responses, that the proposed techniques have a reasonable chance of detecting the possible (Earth modelled) seepage and storage processes.

## 3.4 *OTHER GENERAL LEGAL/REGULATORY ISSUES*

A number of generic legal and regulatory issues have also been identified by Parties and other stakeholders in respect of a project boundary for a CCS projects. The key issues identified include:

i) *Subsurface trans-boundary migration of $CO_2$.* The potential for $CO_2$ migration from one country's' sovereign territory to another creates problems in terms of project approval i.e. which Designated National Authority (DNA) should be responsible for project approval, and for the allocation of any seepage emissions i.e. to which national greenhouse gas (GHG) inventory seepage emissions would be allocated to. There are also legal considerations in this context relating to:

- Whether the adjoining country is a signatory to the Kyoto Protocol;
- Whether the adjoining country(ies) is an Annex I country under the Kyoto Protocol; and;
- Whether the adjoining country(ies) is a signatory to any international conventions relating to the protection of the marine environment (e.g. the London Convention and Protocol) for which the other is not.

ii) *Storage of $CO_2$ beneath international waters.* Activities occurring in international waters are not under the control of any sovereign nation, and are subject to the *United Nations Convention on Law of the Seas* (UNCLOS). As such, any activity would need to be in compliance with UNCLOS. Further issues to consider in this context include:

- Which DNA could provide approval for a project in international waters?
- Does a CCS project in international waters pose any issues for international boundary disputes (e.g. in the South China Sea)?

These issues should be resolved at early stages in a project feasibility study, largely driven by the geological Earth modelling process identified above (in *Section 3.2.3*) which will define the sub-surface project boundary.

Many of these issues are currently under consideration in a number of fora (e.g. the IEA CCS *ad hoc* regulatory group), and largely beyond the scope of CCS CDM methodological issues.

On the whole, the issues raised will principally be concerns of the host country(ies) associated with a specific project, and as such, should be articulated within the appropriate document for host country approval, such as the Environmental Impact Assessment (EIA) component of a CCS CDM project activity. Further analysis of this component is provided below (*Section 10.2.1*) where the role of the EIA in the CDM process (specific to CCS projects) is considered.

Moreover, it is worth noting that many of these issues are typical for oil & gas exploration and production operations, and precedents from these activities could form a useful basis upon which to consider the issues.

### 3.5 *SUMMARY OF ISSUES RELEVANT TO CDM METHODOLOGIES*

The proceeding discussion has attempted to define the various emissions sources that are considered to within a CCS CDM project boundary. Items highlighted include:

- *Above ground installations*: These are considered to present typical engineering components of any CDM project, and as such do not present any new issues in the context of methodology design. All above ground components of a CCS project present the opportunity for $CO_2$ emissions to arise, and consequently, must be considered to be within the project boundary;
- *Wells:* These also present a further potential source of $CO_2$ emissions, and consequently must be considered to be within the project boundary;
- *Subsuface storage formation(s):* Monitoring of the formation(s) and $CO_2$ plume behaviour will be important for verifying permanence of the injected $CO_2$ in the reservoir, and for establishing continued secure $CO_2$ containment for environmental, health and safety reasons. In addition, data collected on plume behaviour will be necessary in order to recalibrate the static and dynamic geological Earth model(s) used to define the storage formation(s) boundary i.e. by identifying deviations from the predicted *dynamic* behaviour – which will be governed by the input parameters in the static geological Earth model(s) and the sensitivity analysis undertaken in dynamic simulations – better knowledge of the subsurface will be gained, which allows the model to be recalibrated (using the principles of history matching and adaptive learning) (1);
- *Area surrounding the sub-surface storage formation(s):* The area around the defined $CO_2$ containment complex must be monitored for the purpose of identifying seepage from the storage formation(s) and to demonstrate separation from other users and uses;
- *Monitoring methodology:* This will be defined by the site characterisation process, the risk assessment, and the definition of the lateral and vertical boundaries of the $CO_2$ containment complex.

These components of a CCS project are critical in defining a monitoring methodology for a CCS CDM project, as discussed below (*Section 9*).

(1) Which is consistent with the approach outlined in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter5 (CCS).

# 4 BASELINE SCENARIO, APPROACH AND EMISSIONS

## 4.1 BACKGROUND

Under the Marrakesh Accords a CDM baseline scenario is defined as…

> *…the scenario which reasonably represents anthropogenic emission that would occur in the absence of the project.*

CDM project proponents must outline a range of different technology investment and deployment scenarios/options associated with a proposed project, and demonstrate the additionality of the proposed project activity ahead of business as usual i.e. that the project activity is not the baseline scenario (1).

The Marrakesh Accords also requires project proponents to select the most appropriate baseline approach to establishing the baseline methodology for the proposed project activity from the following options:

- I. *Existing actual or historical emissions, as applicable;*
- II. *Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment;*
- III. *The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category.*

Upon establishing the appropriate baseline scenario and baseline approach for a project activity, a CDM baseline methodology must be developed. The baseline methodology is a series of accounting algorithms that can be used to estimate baseline emissions i.e. the emissions that would have occurred in the absence of the project. In practice, two methodological approaches can be adopted for the determination of baseline emissions:

- *Ex post*: monitoring of certain parameters relevant to calculating baseline emissions for the determined baseline scenario, post implementation of the project.
- *Ex ante*: preparation of key parameters and calculations relevant to calculating baseline emissions for the determined baseline scenario prior to project implementation.

An *ex ante* baseline methodology will only be necessary where the baseline is independent of the CDM project activity. Typically, this might be the case for afforestation/reforestation CDM project activities; on the whole *ex ante* are not appropriate for energy-related CDM project activities.

(1) The proceeding Section of this report considers additionality in the context of CCS projects.

CCS projects are likely to be suitable for the application of an *ex post* baseline methodology, as changes in performance during the project need to be considered, taking into account annual variations in the plant output and volumes of $CO_2$ captured and stored each year. One exception is likely for EHR projects, where the baseline may need to be calculated *ex ante* based on a scenario of "no further action" (NFA) i.e. what the emissions from the operations would have been under normal operating conditions in the absence of the $CO_2$ flood (see *Section 4.4*).

### 4.2 *METHODOLOGICAL ISSUES*

Taking into consideration the nature of $CO_2$ sources suitable for CCS (*Annex A*), key issues to consider in determining a baseline scenario for a CCS project activity include:

i) *The nature of CCS projects*: CCS projects present a departure from other climate change mitigation technologies, primarily because they are fossil fuel based, they physically reduce emissions at sources that would otherwise be emitted, they can apply to a broad spectrum of activities (including various parts of the fossil fuel cycle), and they can potentially create perverse incentives for higher emitting technologies i.e. perverse incentives could be created for inefficient plant deployment ahead of more efficient technologies, or renewables or biomass technologies (1). Moreover, there is a need to account for the energy penalty presented by CCS applications, which creates additional $CO_2$ per unit output relative to the same process without CCS (see *Annex A*).
ii) *The installation producing the $CO_2$*: Issues associated with determining the baseline scenario will vary greatly between grid-connected power plants and other types of industrial installations. Industrial installations co-capturing combustion and process $CO_2$ streams will also create additional considerations, especially if the $CO_2$ is co-injected with other substances (e.g. $H_2S$ in natural gas sweetening operations).
iii) *New build and retrofit installations*: Baseline scenarios for new-build CCS plants will be different from those determined for retrofit applications, for both power plants and industrial installations. The logical assumption for many would be that the baseline for a CCS project activity should be "avoided $CO_2$" (*Annex A*), however, care must be taken to ensure a level playing field for all emissions mitigation technologies in order to encourage the most cost effective options. There is also an issue around ensuring consistency of incentives for new-build and retrofit CCS applications (2).
iv) *Fuel and technology choices for new build installations*: Appropriate consideration must be given to sufficiently incentivise best available

(1) Notwithstanding this observation, it is facile to consider that fossil fuels will not form the basis of economic development in many countries in the near term. CCS actually presents the only effective option for delivering major cuts in GHG emissions from the power sector in many parts of the world e.g. USA, Europe, China and India (see "The New Face of King Coal" (2005), Zakkour and Cook, Environmental Finance, July 2005. This article outlines that China alone will add 25 GW of new coal plant every year for the next 25 years to meet electricity demand, meaning an additional emissions of 3 $GtCO_2$/yr by 2030. This is some 20 times the UKs current emissions from power plants).
(2) And taking into account type 1 and type 2 baseline approaches. Type 1 (historical emissions of the power plant or installation) would seem logical for retrofits, and a type 2 approach for new-builds (a technology which represents an economically attractive course of action, taking into account barriers to investment).

technology in CCS applications, and avoid creating perverse incentives for fuel switching in certain markets and geographical locations. CCS projects should not be unduly incentivised ahead of other grid-connected zero-emission generating technologies.

v) *Characteristics of retrofits*: Retrofit application of CCS technologies will be complicated by a range of factors including: whether it is an integrated or stand-alone dedicated capture plant with a capacity extension, the nature of the retrofit (integrated or "end-of-pipe"), and whether the power plant was built "capture-ready" (1). Given the interest in deploying capture-ready power plants in many parts of the world, it is probably sensible for the CDM to offer an incentive for these type of plants to be deployed now, if possible.

vi) *Issues for the 2nd and 3rd crediting period*: Due consideration will be necessary as to whether – in retrofit applications – the baseline conditions should be altered after the first crediting period to avoid perversely incentivising retrofits ahead of new-build CCS projects in the longer-term (2). Although this can be undertaken where best-in-class plant or combined margin approaches are taken, it is less clear how this is applicable in the case of a historical emissions based approach (3). As such, it may be necessary that baselines for retrofit projects in the 2nd and 3rd crediting periods default to the new-build approach using the latter. Alternatively, for some new-build industrial installations (such as GTL plants), in order to optimise the overall capture system process, more emissions intensive technologies may be employed than would be in the absence of $CO_2$ capture (4). Thus, in these cases the baseline would need to reflect the best-available technique design in the absence of $CO_2$ capture. In assessing the continued validity of the baseline, a change in the relevant national and/or sectoral regulations between two crediting periods must also be examined at the start of the new crediting period, although it is unlikely that mandatory CCS controls could be in place within the foreseeable future.

A framework for considering these issues is presented below (*Figure 4.1*). The view presented is based on issues i) to vi) outlined above, and provides a useful basis for considering baseline issues for different types of CCS projects.

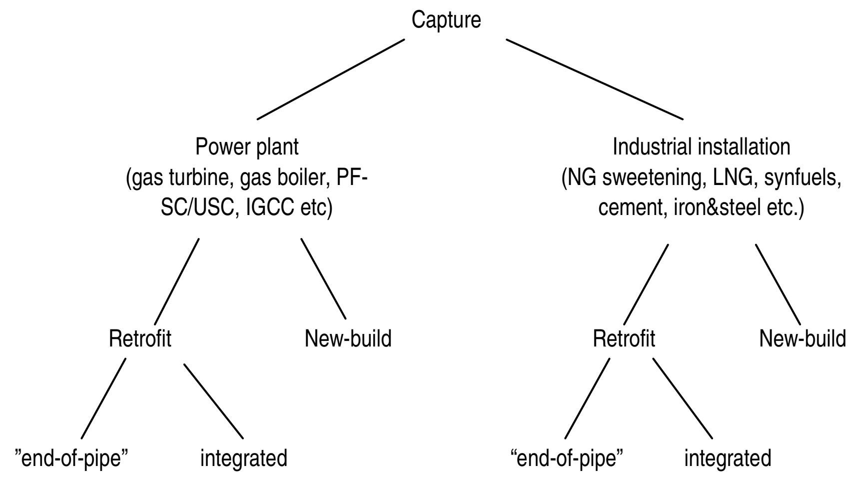
(1) There is no universally accepted definition for a new-build "capture-ready" power plant. Suffice to say that they typically require some extra land to be left aside for installing the capture plant, and require some additional manifolds and steam and $CO_2$ take-off points to be integrated into the plant design.

(2) Assuming that retrofit projects would use a historical emissions approach whilst new-builds will incorporate a dynamic baseline based on the grid to which the project is connected, or best-in-class reference plant approaches.

(3) For a CCS project, readjusting the baseline to reflect the average of the 3 or 4 most recent years of operations would result in the baseline = project emissions i.e. zero emissions reductions.

(4) Such as replacing CCGTs onsite with gas-fired boilers with steam turbines, which delivers overall efficiency savings on the capture side due to the more concentrated stream of $CO_2$ in the boiler flue gas.

*Figure 4.1 Framework for considering baseline scenarios, approaches and accounting*




Based on the framework presented, baseline scenarios, approaches and accounting issues are considered in subsequent parts of this Section, as outlined below (*Section 4.3*).

Precedents already adopted within the CDM which are relevant to these issues must also be taken into consideration (*Annex B* provides detail in this context).

## 4.3 APPROACHES TO BASELINES ACCOUNTING IN CCS PROJECTS

### 4.3.1 Baseline scenario

In determining the baseline scenario for a CCS project, it is important to consider the reasons for deployment of CCS technologies. Currently there are five major drivers for deployment of nascent CCS projects worldwide:

i) *$CO_2$-EHR*: As carried out in places such as the Permian Basin in West Texas, where royalty relief on tertiary produced oil creates an enabling economic environment for $CO_2$-EHR;
ii) *Gas disposal*. As carried out in Canada, where $CO_2$ is co-injected as a by-product with $H_2S$, the latter requiring safe disposal for health, safety and environmental reasons. Injection of $H_2S$ is a cheaper option than its removal as elemental sulphur; $CO_2$ storage is an incidental benefit of these activities;
iii) *Tax avoidance*: As carried out in hydrocarbon production operations on the Norwegian continental shelf (at Sleipner) to avoid the Norwegian $CO_2$ Discharge Tax (currently around €40 per tonne $CO_2$ emitted). BP's planned Peterhead-Miller project is expected to be appropriately incentivised by the EU's GHG Emissions Trading Scheme;
iv) *License to operate*: potential CCS project (Gorgon in Australia) would be deployed as part of the field development license conditions, albeit with sufficient forms of incentives to ensure reasonable or full cost recovery by the developer;

v) *Research and demonstration:* Some small-scale CCS projects (e.g. Frio Brine; Ketzin, RECOPOL) have been deployed for R&D purposes.

In practice, therefore, with the exception of these conditions – which must be considered in demonstrating project additionality (see *Section 5*) – the only reason for CCS project deployment in non-Annex I countries will be the generation of CERs via the CDM coupled with the good will of the project developer to act responsibly toward the environment (since the current value of CERs may not cover the whole cost of the CCS project) [(1)].

As such, the CDM baseline scenario must be considered to be the deployment of the underlying project without CCS. Therefore, contingent on appropriate demonstration of additionality for specific projects, the baseline scenario which reasonably represents the most likely course of action in the absence of the CDM project activity will be venting of generated $CO_2$ direct to the atmosphere.

### 4.3.2 *Baseline approaches*

The framework presented above (*Figure 4.1*) outlined two design approaches to deploying CCS projects:

- Retrofits to existing installations, and
- New-build projects

Sub-elements were also presented covering end-of-pipe and integrated retrofits, the latter essentially representing a new build project (i.e. replanting or repowering).

Based on this framework, the following baseline approaches are considered appropriate for CCS CDM project activities:

- Retrofits – Existing actual or historical emissions, as applicable;
- New builds - Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment;

For some new build projects, it may also be appropriate to consider type III baseline approaches, as follows:

- The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category.

Essentially, this would involve applying a benchmark approach and will be appropriate where a radical departure from standard project design is adopted in order to optimise the system for CCS. An example case might be

(1) Note that for gas processing in high $CO_2$ fields, $CO_2$ capture will be an integral part of the project with or without $CO_2$ storage i.e. the $CO_2$ would be captured and vented in order to meet LNG feed quality or pipeline specifications (see *Section Annex A*).

the deployment of new build LNG train with a centralised CCGT with $CO_2$ capture on the knockout *and* power plant emissions sources.

### *4.3.3 Baseline accounting*

Whilst issues associated with baseline scenarios and baseline approaches for CCS projects can be considered to be straightforward, the baseline accounting methodologies for CCS projects need to carefully consider the range of issues presented above (in *Section 4.2*).

In this respect, a range of CCS project types – and the baseline issues they present – are outlined below (*Table 4.1*).

*Table 4.1 Project types, baseline issues and proposed approaches*

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [P] Power plant | [R] Retrofit | [E] End of pipe | [1] Installation of a post-combustion $CO_2$ capture plant at an existing facility, with power to the capture plant provided by the existing plant with no capacity extension. | This type of project will result in a reduction of the overall thermal efficiency (electrical and/or heat output per unit energy input) of the power plant compared with the baseline scenario, as additional auxiliary power to run the capture facility etc will be required. Whilst the power plant would still create the same amount of $CO_2$ as in the baseline scenario, the reduction in thermal efficiency (loss of output) from the plant would need to be reflected in the baseline accounting methodology. As such, the baseline emissions will need to be calculated based on the historical emission factor per unit output of the plant prior to installation of the capture facility.<br><br>In some cases, this type of project might involve the deployment of a $CO_2$ capture plant at a capture-ready power plant. This would deliver similar ranges of efficiency as for an integrated retrofit project, which will probably need to be based on the precedent set in ACM0002, where the combined margin approach is adopted. This will likely lead to a lower baseline than the historical emissions of the plant. However, given a need to incentivise the deployment of capture-ready technologies now ahead of integrated retrofits that may occur further into the future (1), it may be best to consider the historical emissions as the baseline accounting methodology. This approach would likely need to be redressed at the end of the first crediting period. |

(1) See G8 Gleneagles Plan of Action on Climate Change at: http://www.fco.gov.uk/Files/kfile/PostG8_Gleneagles_CCChangePlanofAction.pdf

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [P] Power plant (cont.) | [R] Retrofit (cont.) | [E] End of pipe | [2] Installation of a post-combustion power plant at an existing facility, including a capacity extension (i.e. new auxiliary power plant) to meet additional load for the $CO_2$ capture facility, but not a replanting project. | In this type of project the electrical and/or heat output of the plant would remain the same as in the baseline scenario, although the overall emissions from the installation would increase (i.e. specific emissions per unit output would increase relative to the baseline). In addition, some projects may also capture $CO_2$ from the new dedicated auxiliary power plant, whilst others may not. This will largely be dependent on project specific scale and economic factors.<br><br>The baseline accounting methodology should be based on the emissions of the plant excluding the emissions from the auxiliary power plant. Emissions from the new auxiliary power plant need to be considered as project emissions where the $CO_2$ is not captured. Where auxiliary plant emissions are captured, then the baseline and project emissions need to take account of these extra emissions. Additional emissions arising from the transport and injection of these emissions will be accounted for in the calculation of project emissions. |
| | | [I] Integrated | [1] Replanting of an existing power plant, using either pre- or post-combustion or oxyfuel capture technology | An integrated retrofit is likely to increase the overall thermal efficiency of the CCS scheme compared to an end-of-pipe retrofit. Essentially the baseline accounting methodology for this type of retrofit should be the same as for new builds (outlined below). |
| | | [I] Integrated | [2] Installation of a coal gasifier with pre-combustion capture on a natural gas turbine. | There is a possibility that some projects could involve retrofitting of natural gas fired turbines (CCGT) with a coal gasifier upfront of the turbine so that the turbine fires coal syngas as opposed to natural gas. This would involve the application of pre-combustion $CO_2$ capture technology at the plant. For these project types, the baseline accounting methodology could be based on the equivalent emissions of the coal gasifier or the equivalent emissions from a natural gas turbine (e.g. based on the thermal efficiency presented by the OECD best-in-class technology, or the most representative technology given local market conditions). To avoid such as dilemma, it may be best to consider the use of the combined margin (as for new-builds) for these types of projects. |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [P] Power plant (cont.) | [N] New build | [-] | [1] Post-combustion capture – coal or natural gas | Post-combustion capture processes are likely to be the most widely deployed CCS technology for fossil fuel powered plants in the near term due to technology maturity and ease of installation and operation.<br><br>The baseline accounting methodology for these projects should be based on the combined margin of the electricity grid to which the project is connected, weighted based on the position in the merit order which the plant might be in the grid to which it is connected (which is most likely to be baseload). |
| | | [-] | [2] Pre-combustion capture – coal or natural gas | Pre-combustion capture processes are an emerging technology as gasifier technology improves. In many cases these will deliver better thermal efficiencies than post-combustion capture because of the efficiency gains that can be made on the capture facility (i.e. the energy penalty in pre-combustion processes is lower than for post-combustion capture technologies)<br><br>The baseline accounting methodology for these projects should be based on the combined margin approach based on the electricity grid to which the project is connected, weighted based on the position in the merit order which the plant might be in the grid to which it is connected (which is most likely to be baseload). |
| | | [-] | [3] Oxyfuel firing – coal | Oxyfuel firing technologies are presently at a research stage (see *Annex A*).<br><br>The baseline accounting methodology for these projects should be based on the combined margin approach based on the electricity grid to which the project is connected, weighted based on the position in the merit order which the plant might be in the grid to which it is connected (which is most likely to be baseload). |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| | | [-] | [4] Other emerging capture technologies | Embryonic capture technologies have not been considered in detail (see *Annex A*).<br><br>The baseline accounting methodology for these projects should be based on the combined margin approach based on the electricity grid to which the project is connected, weighted based on the position in the merit order which the plant might be in the grid to which it is connected (which is most likely to be baseload). |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [I] Industrial Installations | [R] Retrofit | [E] End-of-pipe | [1] Capture of $CO_2$ in natural gas production & processing installations | Production of natural gas from high $CO_2$ (also know as low BTU) gas fields usually requires processing of the gas to remove some or all of the $CO_2$. In sour gas fields, acid gas ($H_2S$) will also be removed and can be co-injected with $CO_2$ (if present). The $CO_2$ and $H_2S$ (or a portion of it) is usually removed near the well-head to reduce transportation costs and reduce corrosion risks in pipelines. The process produces a relatively pure $CO_2$ stream (see *Annex A*).<br><br>Natural gas production & processing facilities will also have natural gas fired combustion plants present for powering operations. In the vast majority of cases it is unlikely that $CO_2$ produced from this component of the facility will be captured due to the costs (which are similar to capture at power plants)(1). However, it is important to note that the power requirements for $CO_2$ injection operations (even for the processing emissions) will create additional emissions from the power plant on the installation; these must be taken into account as project emissions.<br><br>In the absence of capture from the power plant, the baseline accounting methodology should be based on the amount of processing $CO_2$ captured and stored i.e. the amount of $CO_2$ that would be vented in the absence of the project. Project specific factors should also be taken into account in respect of the contracted delivery quality of the natural gas (2). Where $H_2S$ removal processes are dispensed with in the project scenario, i.e. co-injection of the $H_2S$ with $CO_2$, emissions from the $H_2S$ processing unit should be included in the baseline. |

(1) Note: The Sliepner project only reinjects $CO_2$ from gas processing, but not the combustion emissions.

(2) For example, gas turbines in some locations can be modified to fire on natural gas with up to 17% $CO_2$ content. It is also worth noting, however, that it will be easier to remove the $CO_2$ at this stage in the fuel cycle than at a power plant using the produced natural gas.

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| | | | [2] Capture of $CO_2$ in LNG production installations | Retrofit end-of-pipe capture of $CO_2$ at LNG facilities presents similar issues as for capture in natural gas processing, with the main difference for LNG facilities being that even low levels of $CO_2$ must be removed to avoid dry-ice forming in the liquefaction plant (see *Annex A*). Issues for the baseline and project emissions accounting methodology are the same as for natural gas processing (1). |
| [I] Industrial Installations (cont.) | [R] Retrofit (cont.) | [E] End-of-pipe (cont.) | [3] Capture at refineries | End-of-pipe capture at refineries would involve the capture at $CO_2$ produced in gas and oil fired heaters, cogeneration plant, and from gasifiers or thermal reformers producing hydrogen for use on the refinery (see *Annex A*). Retrofit applications will involve the application of pre- and post-combustion capture technologies on the appropriate point sources of $CO_2$ in the installation; the sources subject to retrofit capture will be determined by the project specific economics of capturing each source stream. Some projects may also include $CO_2$ capture from onsite power plant used to generate process steam and/or power, depending on scale and economics factors. Some projects may also require a capacity extension (employing a new auxiliary power plant to power the capture facility).<br><br>The baseline accounting methodology for end-of-pipe retrofit refinery projects should be based on historical emissions from the relevant sources included in the project. Emissions arising from the additional power required for the capture facility will need to be considered as project emissions in the accounting methodology. |

(1) Note: Neither Statoil's Snohvit LNG project or Chevron's Gorgon LNG Project – both of which will employ CCS for $CO_2$ removed from the natural gas, but not for combustion sources.

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| | | | [4] Capture in synfuel production installations | End-of-pipe capture at synfuel plants will likely involve the addition of a $CO_2$ capture facility on the gasifier off-gas stream. Some projects may also include $CO_2$ capture from onsite power plant used to generate process steam and/or power, depending on scale and economic factors. Some projects may also require a capacity extension (employing a new auxiliary power plant to power the capture facility).<br><br>The baseline accounting methodology for end-of-pipe retrofit synfuel production projects should be based on historical emissions from the relevant sources included in the project. Emissions arising from the additional power required for the capture facility will need to be considered as project emissions in the accounting methodology. |
| | | | [5] Capture at cement installations | Installation type specific factors need to be considered. Due to the constraints of this study, specific issues relevant to cement plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |
| [I] Industrial Installations (cont.) | [R] Retrofit (cont.) | [E] End-of-pipe (cont.) | [6] Capture iron & steel production installations | Installation type specific factors need to be considered. Due to the constraints in this work, specific issues relevant to iron & steel plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |
| | | | [7] Chemical installations | Installation type specific factors need to be considered. Due to the constraints in this work, specific issues relevant to chemical plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [I] Industrial Installations (cont.) | [R] Retrofit (cont.) | [I] Integrated | [1] Capture of $CO_2$ in natural gas production & processing installations | An integrated retrofit at a gas processing facility might involve the installation of a CCGT natural gas power plant or a gas thermal reformer with $H_2$ fired turbines, and the application of mechanical drives for power requirements. This could result in the creation of a large point source of $CO_2$ which is more suitable for the application or pre- or post-combustion capture on the combustion emissions source.<br><br>The baseline accounting methodology for this type of project could be based on the historical emissions for the installation prior to project implementation. If the retrofit results in a minor capacity extension, historical emissions could still be considered as appropriate (e.g. for a capacity extension of less than fifteen percent (<15%; equal to the maximum energy penalty one might expect)). If the retrofit involves a major repowering or capacity extension to the plant (e.g. >15%), the project should be considered as a new build project and be subject to the baseline accounting methodology applicable to new build projects (see below). |
| [I] Industrial Installations (cont.) | [R] Retrofit (cont.) | [I] Integrated (cont.) | [2] Capture of $CO_2$ in LNG production installations | An integrated retrofit at an LNG facility could involve the conversion from multiple OCGTs or aero-derivative power trains to a single centralised CCGT plant (see *Annex B*). A further option could involve the deployment of gas boilers with steam turbines as replacement for gas turbines, which, whilst reducing the thermal efficiency of the installation, would deliver overall efficiency savings on the capture side. This is because the $CO_2$ concentration in flue gas from a natural gas boiler is around 10%, as opposed to 3-4% from a gas turbine, making the flue gas more amenable to $CO_2$ capture.<br><br>The baseline accounting methodology approach is considered to be the same as outlined for natural gas production and processing above. |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| | | | [3] Capture at refineries | An integrated CCS retrofit at a refinery would likely consist of re-powering some or all of the gas and oil fired heater units. Modification or efficiency improvements to gasifiers, including per-coke gasification, may also be a feature.<br><br>The baseline accounting methodology approach is considered to be the same as outlined for natural gas production and processing above. |
| | | | [4] Capture in synfuel production installations | An integrated CCS retrofit at a synfuel plant would likely involve a major redesign of the plant to optimise overall plant efficiency. This could involve a change in syngas forming technology, F/T plant design, or hydro-processing in order to optimise systems and produce more concentrated $CO_2$ sources at certain points in the system to facilitate capture.<br><br>The baseline accounting methodology approach is considered to be the same as outlined for natural gas production and processing above. |
| [I] Industrial Installations (cont.) | [R] Retrofit (cont.) | [I] Integrated (cont.) | [5] Capture at cement installations | Installation type specific factors need to be considered. Due to the constraints of this study, specific issues relevant to cement plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |
| | | | [6] Capture iron & steel production installations | Installation type specific factors need to be considered. Due to the constraints in this work, specific issues relevant to iron & steel plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |
| | | | [7] Chemical installations | Installation type specific factors need to be considered. Due to the constraints in this work, specific issues relevant to chemical plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [I] Industrial Installations | [N] New-build | [-] | [1] Capture of $CO_2$ in natural gas production & processing installations | New build gas production & processing installations utilising CCS technologies will present similar issues as for retrofits, as essentially most of these project types involve the capture and injection of process $CO_2$ that would otherwise be vented. There is a need to avoid creating a perverse incentive to develop more marginal high $CO_2$ gas fields ahead of other gas field development projects in the near term (see *Section 5* on *Additionality* for a discussion of this issue).<br><br>Assuming appropriate demonstration of additionality, then the baseline accounting methodology for these types of projects should be the emissions that are captured and stored i.e. the emissions that would have been vented direct to the atmosphere in the absence of the project. Additional power plant emissions arising as a consequence of deploying CCS need to be counted as project emissions. Where capture is employed at onsite power plants (which is a possibility but seems unlikely under present project economics), then the baseline emissions must be adjusted accordingly to take account of the capture penalty associated with CCS operations. |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [I] Industrial Installations (cont.) | [N] New-build (cont.) | [-] | [2] Capture of $CO_2$ in LNG production installations | New build LNG installations utilising CCS technologies will present similar issues as for retrofits, as essentially most of these project types involve the capture and injection of process $CO_2$ that would otherwise be vented. However, there is a need to avoid creating a perverse incentive to develop marginal high $CO_2$ gas fields ahead of other gas field development projects in the near term (see *Section 5* on *Additionality* for a discussion of this issue).<br><br>The same baseline accounting methodology outlined for new build natural gas production & processing installations are appropriate. The exception to this could be where there is a departure from conventional LNG plant design (for example using a single CCGT with $CO_2$ capture for power generation). In these situations, project proponents should select whether to develop a baseline using either:<br>• A modelling approach to estimate $CO_2$ emission per unit output based on construction of the same installation without CCS; or,<br>• A benchmark approach to estimate $CO_2$ emission per unit output based on a review of the five most recently constructed LNG trains around the world.<br>This approach would only be applicable to calculating the baseline emissions associated with the combustion plant emissions in the LNG facility; calculation of process emissions using the approach outlined above (i.e. captured and stored emissions) would still be applicable. |
| | | | [3] Capture at refineries | In new build refineries utilising CCS consideration must be made of the design philosophy adopted at the refinery. Gathering of emissions from disparate fired-heaters and other off-gas sources (e.g. from $H_2$ production plants) into a single capture plant is likely to be expensive due the costs of pipework, and therefore, innovations in overall design schemes can be expected in systems optimised for CCS applications. As such, the baseline accounting methodology should follow that proposed for the combustion emissions in new build LNG production installations, as outlined above. |

| Installation type | CCS application | Design approach | Option | Baseline accounting issue |
|---|---|---|---|---|
| [I] Industrial Installations (cont.) | [N] New-build (cont.) | [-] | [4] Capture in synfuel production installations | There are a number of different technology options for syngas formation technology in a new-build synfuel plant, including: steam reforming, partial oxidation, autothermal reforming and combined or two-step reforming. The choice of the syngas former will be dictated by scale and economic factors. The choice of syngas former will have an influence on the overall thermal efficiency of the synfuel plant, and therefore overall emissions. Presently, there is no widely accepted best-available-techniques for synfuel production, whilst many designs are subject to patents. As such, baseline accounting methodologies for new build synfuel installations with CCS will need to be considered on a project specific basis, taking into account project size, local circumstances, and appropriate articulation by project participants of the baseline in the same way as for the combustion emissions in new build LNG production installations, as outlined above. |
| | | | [5] Capture at cement installations | Installation type specific factors need to be considered. Due to the constraints of this study, specific issues relevant to cement plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |
| | | | [6] Capture iron & steel production installations | Installation type specific factors need to be considered. Due to the constraints in this work, specific issues relevant to iron & steel plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |
| | | | [7] Chemical installations | Installation type specific factors need to be considered. Due to the constraints in this work, specific issues relevant to chemical plants have not been considered and should be subject future research. A place holder for this work should be included in the methodology developed. |

In addition to the methodological approaches proposed above, other factors that need to be considered in developing a CCS CDM baseline accounting methodology also include:

- Issues relating to the extension of the lifetime of a plant in retrofit projects; and,
- Changes in the baseline in the 2nd and 3rd crediting period

Some thoughts in this context have been outlined above (*Section 4.2*) and also under *Leakage* (*Section 6.2*).

### *4.4* *BASELINE ACCOUNTING ISSUES FOR EHR PROJECTS*

As outlined previously, application of an *ex ante* baseline methodology may be necessary for EHR projects, where the $CO_2$ flood operation serves to increase the field life compared to the "no further action"(NFA) scenario, or other secondary or tertiary (1) recovery techniques not employing anthropogenic $CO_2$ (e.g. naturally occurring [mined] $CO_2$, nitrogen, or steam). In other words, what the emissions from the operations would have been under normal operating conditions in the absence of the $CO_2$ flood.

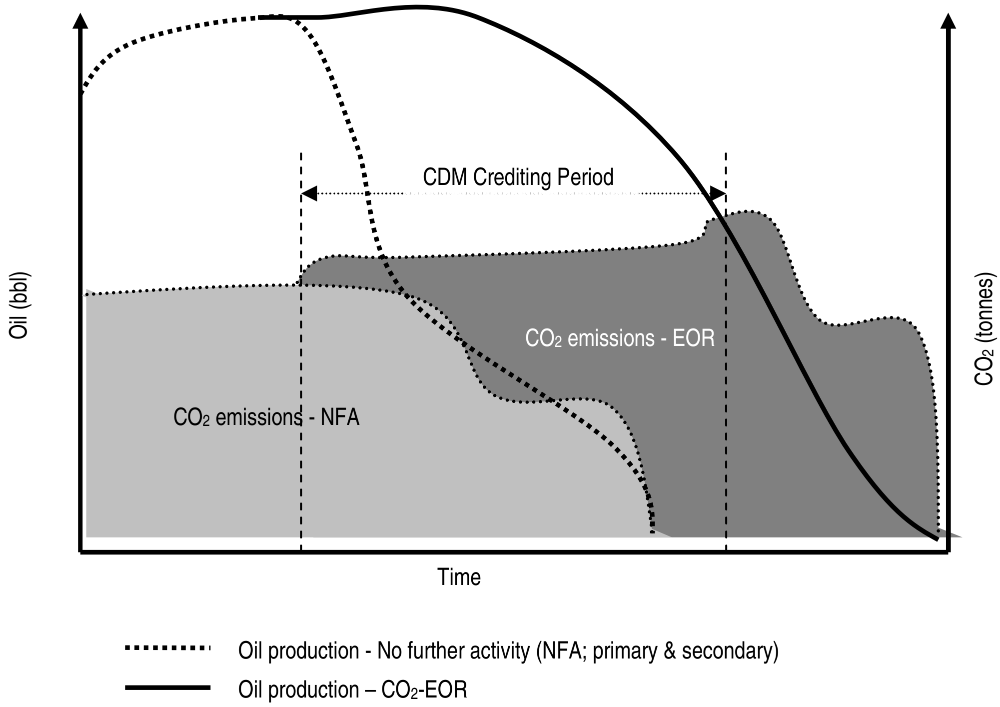
Under these circumstances, project proponents should adopt a two step process to determining firstly the baseline scenario, and subsequently the baseline emissions, as follows:

- *Step 1:* As part of the demonstration of additionality, project proponents would need to outline how the field might be developed in the absence of the anthropogenic $CO_2$ flood. They will also need to demonstrate financial additionality and barrier analysis to demonstrate why anthropogenic $CO_2$ flooding is not the baseline. Further discussion in this context is provided below (*Section 5*).
- *Step 2:* On establishing the appropriate baseline scenario, project proponents would need to then estimate the emission baseline associated with the relevant option identified in Step 1.

An example of how the baselines might look in a NFA scenario relative to a $CO_2$-EOR operation scenario are illustrated below (*Figure 4.2*).

(1) Around 25-35% of the original oil in place can be recovered using secondary techniques, such as water flood or mechanical lift (pumping). A further 5-15% of the original oil in place can be recovered using tertiary techniques (thermal recovery [steam], nitrogen, carbon dioxide etc.)

*Figure 4.2 Relative baseline for $CO_2$-EOR projects*




In the figure, the total $CO_2$ emissions associated with operations under the NFA scenario are shown in light grey; the dark grey shows the emissions profile under the EOR scenario. This suggests that higher emissions are generated as consequence of the $CO_2$-EOR operation relative to the NFA baseline.
Note: the figure is only illustrative

Source: Based on analysis undertaken by Peter Marsh, Shell.

Based on *Figure 4.2*, for $CO_2$-EOR projects, part of the baseline could consist of the emissions under the NFA scenario or the baseline employing other credible alternatives for tertiary oil recovery excluding anthropogenic $CO_2$ flooding, whilst project emissions associated the $CO_2$-EOR operation must be accounted for.

The additional emissions occurring beyond the CDM crediting period are considered under *environmental additionality* reviewed below (*Section 5.3.2*).

## *4.5 SUMMARY OF RELEVANT BASELINE METHODOLOGIES*

*Table* 4.2 below summarises recommended baseline accounting methodologies for the range of CCS projects considered in this report, based on those issues discussed in this section.

*Table 4.2 Summary of baseline methodologies*

| Project module | Description | Baseline accounting methodology |
|---|---|---|
| P.R.E.1 | Installation of a post-combustion $CO_2$ capture plant at an existing facility, with power to the capture plant provided by the existing plant with no capacity extension. | Baseline emissions are calculated based on the historical emissions factor per unit electrical output in the absence of the $CO_2$ capture process. Careful consideration may be needed where $CO_2$ capture is deployed at "capture-ready" power plants. |
| P.R.E.2 | Installation of a post-combustion power plant at an existing facility, including a capacity extension (i.e. new auxiliary power plant) to meet additional load for the $CO_2$ capture facility, but not a replanting project. | Baseline emissions are calculated based on historical emissions of plant *excluding* new auxiliary plant emissions. If emissions from auxiliary plant are captured, baseline and project emissions must account for this new emissions source. |
| P.R.I.1 | Replanting of an existing power plant, using either pre- or post-combustion or oxyfuel $CO_2$ capture technologies | Baseline emissions calculated based on combined margin of the electricity grid to which the project is connected. |
| P.R.I.2 | Installation of a coal gasifier with pre-combustion $CO_2$ capture on an existing natural gas turbine. | Baseline emissions calculated based on best-in-class or locally representative technology for coal gasifier or natural gas turbine. |
| P.N.1 | Application of post-combustion $CO_2$ capture – coal, lignite or natural gas at a new-build power plant | Baseline emissions calculated based on combined margin of the electricity grid to which the project is connected. |
| P.N.2 | Application of pre-combustion $CO_2$ capture – coal, lignite or natural gas at a new-build power plant | As for P.N.1 |
| P.N.3 | Application of oxyfuel firing with $CO_2$ capture– coal or lignite - at a new-build power plant | As for P.N.1 |
| P.N.4 | New build power plant utilising other emerging $CO_2$ capture technologies | As for P.N.1 |
| I.R.E.1 | Retrofit of $CO_2$ capture an existing natural gas production & processing installation without any change in plant configuration. | Baseline emissions calculated based on amount of processing $CO_2$ captured and stored. Where $CO_2$ is also captured from power generation units, Power [P] module approaches apply as appropriate. |
| I.R.E.2 | Retrofit of $CO_2$ capture at an existing LNG production installation without any change in plant configuration. | As for I.R.E.1 |
| I.R.E.3 | Retrofit of $CO_2$ capture at an existing refinery without any change in plant configuration. | Baseline emissions calculated based on historical emissions from all relevant capture points prior to project implementation. |
| I.R.E.4 | Retrofit of $CO_2$ capture at an existing synfuel production installation without any change in plant configuration. | As for I.R.E.3 |

| Project module | Description | Baseline accounting methodology |
|---|---|---|
| I.R.E.5 | Retrofit of $CO_2$ capture at an existing cement production installation without any change in plant configuration. | Installation type specific factors need to be considered. |
| I.R.E.6 | Integrated retrofit of $CO_2$ capture at an existing iron & steel production installation without any change in plant configuration. | Installation type specific factors need to be considered. |
| I.R.E.7 | Integrated retrofit of $CO_2$ capture at an existing chemical installation without any change in plant configuration. | Installation type specific factors need to be considered. |
| I.R.I.1 | Integrated retrofit of $CO_2$ capture an existing natural gas production & processing installation, including changes in plant configuration | Baseline emissions calculated based on historical emissions from all relevant capture points prior to project deployment. Where retrofit involves >15% capacity extension or re-powering, the project should be considered a new build project (see I.N.1.7 below) |
| I.R.I.2 | Integrated retrofit of $CO_2$ capture at an existing LNG production installation , including changes in plant configuration | See I.R.I.1 |
| I.R.I.3 | Integrated retrofit of $CO_2$ capture at an existing refinery, including changes in plant configuration | As for I.R.I.1 |
| I.R.I.4 | Integrated retrofit of $CO_2$ capture at an existing synfuel production installation, including changes in plant configuration | As for I.R.I.1 |
| I.R.I.5 | Integrated retrofit of $CO_2$ capture at an existing cement production installation, including changes in plant configuration | Installation type specific factors need to be considered. |
| I.R.I.6 | Integrated retrofit of $CO_2$ capture at an existing iron & steel production installation, including changes in plant configuration | Installation type specific factors need to be considered. |
| I.R.I.7 | Integrated retrofit of $CO_2$ capture at an existing chemical installation , including changes in plant configuration | Installation type specific factors need to be considered. |
| I.N.1 | Capture of $CO_2$ at a new-build natural gas production & processing installation | Baseline emissions calculated based on amount of processing $CO_2$ capture and stored i.e. the emissions that would have been vented direct to the atmosphere in the absence of the project. Where capture is deployed at onsite power generation units, baseline emissions must be adjusted accordingly to take account of the capture penalty associated with CCS deployment. |

| Project module | Description | Baseline accounting methodology |
|---|---|---|
| I.N.2 | Capture of $CO_2$ at a new-build LNG production installation | As for I.N.1; in some cases where there is a departure from conventional LNG design, project proponents should select whether to develop a baseline (for combustion plant emissions only) using either (a) a modelling approach to estimate $CO_2$ emissions per unit output based on construction of the same installation without CCS; or (b) a benchmark approach to estimate $CO_2$ emissions per unit output based on a review of the five most recently constructed LNG trains world-wide. |
| I.N.3 | Capture of $CO_2$ at a new-build refinery | As for I.N.2 |
| I.N.4 | Capture of $CO_2$ at a new-build synfuel production installation | No widely accepted BAT for synthetic fuel production. Baseline emissions should be considered on a project-specific basis, taking into account project size, local circumstances etc as for I.N.2 (a) or (b) above. |
| I.N.5 | Capture of $CO_2$ at a new-build cement production installation | Installation type specific factors need to be considered. |
| I.N.6 | Capture of $CO_2$ at a new-build iron & steel production installation | Installation type specific factors need to be considered. |
| I.N.7 | Capture of $CO_2$ at a new-build chemicals installation | Installation type specific factors need to be considered. |

# 5 ADDITIONALITY

## 5.1 BACKGROUND

Under the Marrakesh Accords, a CDM project activity is additional …

> *… if anthropogenic emissions of greenhouse gases by sources are reduced below those that would have occurred in the absence of the registered CDM project activity.*

As explained in the discussion above regarding baseline scenarios for CCS projects, the typical baseline for a CCS project in both Annex-I and non-Annex I countries is the $CO_2$ emissions emitted to the atmosphere by the underlying project activity without CCS.

Thus, demonstration of additionality for CCS projects should be reasonably straightforward. Specific items to consider in demonstrating additionality for CCS projects will include:

- Options for alternatives to the project in order to determine the baseline scenario;
- Consideration of national or sectoral policies relevant to CCS and/or EHR;
- Financial additionality;
- Barriers to deployment.

In addition, there is likely to also be a need to consider two other issues, covering:

- Avoidance of perverse incentives for deploying CCS as a CDM project activity; and,
- Possible demonstration of *environmental additionality*.

The items and issues outlined above are considered in greater detail in the preceding sections.

## 5.2 KEY ADDITIONALITY CONSIDERATIONS

### 5.2.1 *Identifying and evaluating alternatives*

There are really only a handful of options to consider as alternatives for any CCS project, covering:

i) Emitting – or venting – the $CO_2$ directly to the atmosphere;
ii) Capturing and exporting the $CO_2$ for use in industrial applications e.g. for food and beverage production (1);

(1) Although supply will greatly outstrip demand for these types of applications.

iii) Incidental capture and injection of $CO_2$ into geological formations as part of a waste disposal strategy, without consideration of the climate change mitigation benefits (e.g. acid gas injection);
iv) Capturing and injecting the $CO_2$ into geological formations purely for EHR purposes (i.e. without consideration of the climate change mitigation benefits); or,
v) Capturing and injecting the $CO_2$ for climate change mitigation benefits not as a CDM project activity (e.g. for research and demonstration); and,
vi) For EHR projects, the undertaking of tertiary oil recovery using another form of solvent to flush the reservoir (e.g. water, steam or nitrogen).

A summary of the key drivers for undertaking CCS activities not as a CDM project activity was provided above when baseline scenarios were reviewed (*Section 4.3.1*). Based on this analysis, project proponents would need to demonstrate that none of those drivers were present in the region where the project is proposed, or drivers are present but barriers exist to deploying such activities. This would form the basis for the demonstration of additionality for any CCS project.

### 5.2.2 *Consideration of national or sectoral polices*

At present no jurisdiction anywhere in the world enforces mandatory requirements to capture and store large point source $CO_2$ emissions from power plants or industrial installations. Similarly, there are no laws in place which mandate the use of $CO_2$ for enhanced hydrocarbon production, although tax relief may be available for tertiary recovered oil (1).

In most jurisdictions, acid gas ($H_2S$) disposal is mandated by law and also for health and safety reasons. Typically operators apply thermal incineration or sulphur mineralisation technologies. Both of these are emissions intensive activities, and do not result in any emission reductions benefits. In locations where acid gas injection is practiced, then incidental climate change benefits can be realised. However, operators will generally try to avoid co-injection of $CO_2$ as this creates additional volumes of gas to be handled, increasing overall costs.

Therefore, in demonstrating additionality for acid gas co-injection projects, project proponents should assess the range of options for financial and other barriers in demonstrating the additionality of the project.

For all other scenarios, assessment of local laws and regulations for $CO_2$ emissions for different installation types should be considered (2).

(1) This could be driven by the license agreement for the field and the conditions around ultimate recovery of original oil in place (in %). High ultimate recoveries may only be achievable using tertiary recovery, such as $CO_2$-EOR.
(2) It is unclear whether R&D projects could qualify as CDM project activities.

### 5.2.3 *Financial additionality in EHR and acid gas co-injection projects*

In any CCS project other than an EHR or acid gas co-disposal projects, demonstration of financial additionality will not be required, as inherently there is no economic benefit involved with capture and storing the $CO_2$.

In the case of EHR and acid gas co-disposal projects, project proponents should demonstrate financial additionality using IRR to demonstrate that the project would not take place in the absence of CER revenues.

In many cases, barrier analysis will also likely be required in order to demonstrate additionality.

### 5.2.4 *Barriers analysis*

Although the IRR of some EHR or acid gas injection projects could appear attractive, there are likely to be technical barriers to deployment in many circumstances. For example, presently common practice in many parts of the world for acid gas disposal is not injection. Similarly, $CO_2$-EOR has never been carried out offshore, or in certain types of reservoirs or certain grades of crude oil. As such, the technology is unproven under many conditions. EGR and ECBM activities are largely unproven, even at a demonstration level.

There are also likely to be significant technical barriers with regards to different $CO_2$ capture technology applications, and also in transporting $CO_2$ from source to storage location. Whilst many of the component parts for CCS capture at power plants have been demonstrated in other industries – albeit at a smaller scale – application of large scale $CO_2$ capture to flue gas streams has yet to be fully proven (see *Annex A*).

All of these factors should be considered in a barriers analysis, taking into consideration the range of alternatives for $CO_2$ management outlined above.

## 5.3 *FURTHER ADDITIONALITY CONSIDERATIONS*

Two other potential items exist that should be subject to additionality considerations, as reviewed below.

### 5.3.1 *Avoiding perverse incentives*

In some exceptional circumstances, there may be perverse incentives presented by CCS projects in the CDM. This covers two potential scenarios:

i) incentivising low-efficiency technologies ahead of more efficient ones, or
ii) development of projects with high $CO_2$ offgas streams ahead of other less $CO_2$ intensive projects.

To avoid type *i)* scenarios, full consideration of the technology choices employed in the project should be made in order demonstrate that the project will involve use of best available techniques for the particular application, taking into account regional circumstances i.e. applying common-practice analysis. This will also form an important consideration in assessing technology transfer.

Type *ii)* scenarios apply to natural gas processing streams. To avoid incentivising the development of high $CO_2$ gas fields ahead of other options, project proponents should demonstrate that the field would have been developed without CCS in the absence of the CDM.

### 5.3.2 *Assessing environmental additionality*

Several challenging emission accounting issues are posed by CCS projects involving $CO_2$-EOR [(1)] under the CDM. In particular, the following issues present complexities in project accounting:

- *The timespan over which EOR projects operate relative to CDM crediting*: $CO_2$-EOR projects generally operate over long time frames (30-40 years), which is in excess of the maximum CDM crediting period (21 years). Consequently, the project will continue to generate emissions beyond the CDM crediting period (see *Figure 4.2*);
- *The nature of emissions from EOR towards the end of the project*: As $CO_2$-EOR projects reach the end of their life, greater volumes of $CO_2$ will be generated relative to the hydrocarbon recovered [(2)], meaning that higher emissions will occur in the final stages of the project (see *Figure 4.2*). This will likely only be evident beyond the end of the CDM crediting period;
- *Incremental oil produced by the project*: $CO_2$-EOR projects result in incremental hydrocarbon production above a NFA baseline (see *Section 4.4*), which may need to be accounted for. Problematically, accounting for these emissions presents significant challenges as it is unclear whether such incremental production will affect demand for hydrocarbon at the margin. There are also other factors to consider, such as which production it could displace at the margin [(3)]. Whilst these emissions could be considered as *leakage*, it will be virtually impossible to measure and attribute these emissions to the project activity.

Therefore, this report has introduced the concept of *environmental additionality* – as referred to in several sections – as one possible means by which such emissions occurring outside of a project's temporal and spatial boundary might be accounted for.

Under this proposed concept, the project proponent might be required to outline and quantify a full carbon balance across the whole life-cycle of the project – including estimates of the emissions associated with combustion of the incremental hydrocarbons produced – to demonstrate that the project delivers a net emission reduction [(4)].

(1) This Section refers only to EOR projects. Other types of enhanced hydrocarbon recovery (EGR, ECBM) are still at demonstration phases of development.

(2) As more $CO_2$ breaks-through, oil recovery decreases, and greater energy is required to removed and re-inject the breakthrough $CO_2$.

(3) These are considered further in the discussion on Leakage (see *Section 6.3.3* and also in *Annex C*).

(4) These sorts of analysis have been carried out for nascent CCS EOR projects such as BP's DF1 project.

Furthermore, the project should demonstrate that the net emissions reduction calculated exceeds the emissions reductions estimated for the CDM component of the project activity. Where this cannot be demonstrated – taking into account error margins in the analysis – then the project could be rejected on the basis of not being additional in terms of emission reductions, and therefore not registered as a qualifying CDM project activity.

This is just one possible proposed approach to tackling these issues. There may be other options which have not been considered

# 6 LEAKAGE

## 6.1 BACKGROUND

Under the Marrakesh Accords leakage in the CDM is defined as…

> *…the net change of anthropogenic emissions by sources of greenhouse gases (GHG) which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity* (1)*.*

Leakage has been highlighted as a key issue for CCS projects in the CDM by a number of observers, including the CDM EB and by various Parties submitting comments to the SBSTA24 workshop on CCS in the CDM.

## 6.2 METHODOLOGICAL ISSUES

Key issues to consider in respect of leakage emissions attributable to a CCS project activity include:

i) *Upstream fuel-cycle emissions*: Covering upstream emissions due to a CCS project activity and in particular any extra emissions created due to additional energy consumption as a result of the energy penalty imposed by $CO_2$ capture and transportation to the storage site.
ii) *Biomass leakage*: In projects involving biomass co-firing, leakage emissions may be created through transportation of the biomass, and also removal of biomass from the market place which could lead to the use of fossil fuels at another location that was previously using the biomass.
iii) *Enhanced hydrocarbon recovery*: Covering emissions arising from the combustion of hydrocarbon fuels produced by the project activity, which will occur outside of the project boundary.
iv) *Additional materials consumption*: Covering power plant or industrial installation construction, materials use specific to the CCS project activity e.g. chemical solvents used for $CO_2$ capture in pre and post-combustion systems, and disposal of any spent solvent waste material.
v) *Project lifetime issues*: Covering any additional resource consumption created by the project activity that may occur beyond the CDM crediting period e.g. ongoing $CO_2$ recycling that may occur in a $CO_2$-EHR project, and enhanced production in the periods beyond the last CDM crediting year.
vi) *Electricity market effects*: Application of CCS at power plants will increase the specific cost of electricity production, which could have a secondary effect of increasing electricity prices.

Note that when considering above ground installations within the project boundary, any bought-in gas or power used to run components of the CCS

(1) Leakage in the CDM has a *spatial* interpretation, not a *temporal* interpretation (Sudhir Sharma, UNFCCC Secretariat, *pers comm.*, 7th August 2006). Consequently, seepage from storage reservoirs beyond the crediting period for a CDM project activity cannot be considered as a type of leakage.

project are considered to be within the project boundary (see *Section 3.2.1*), and thus must be accounted for as project emissions (see *Section 7*).

There are also certain other leakage accounting issues that must be considered including:

- Approaches for accounting for leakage already applied in the CDM;
- Adoption of the principles of transparency and conservativeness;

Precedents already within the CDM relevant to leakage issues presented by CCS projects are reviewed in *Annex C*.

### 6.3 *APPROACHES TO LEAKAGE ACCOUNTING IN CCS PROJECTS*

The analysis provided in *Annex C* highlights the range of approaches adopted to date to account for leakage in approved CDM methodologies. The review also demonstrates the divergence in approaches in different methodologies. Consequently, in the absence of clear guidance and precedents to similar issues so far, it is difficult to identify specific approaches that can be directly applied on a CCS CDM methodology. However, suffice to say that any approach must be coherent with the principles of transparency and conservativeness.

Notwithstanding this divergence, suggested approaches to handling leakage in a CCS CDM project methodology are outlined below (*Table 6.1*).

***Table 6.1 Proposed approaches to accounting for leakage in CCS projects***

| Issue | Approach |
|---|---|
| Upstream fuel cycle emissions | CCS projects utilising fossil fuel should account for leakage as a result of any increases in upstream fuel cycle emissions, covering:<br>• Fossil fuel combustion in extraction and processing:<br>• Fugitive emissions in extraction and processing<br>• Fossil fuel combustion in fuel transportation<br>• Fugitive emissions in fuel transportation:<br>The accounting methodology must only account for any incremental increases in emissions relative to what the upstream emissions would have been in the absence of the project, based on the appropriate baseline scenario for the project. These will be different for new build projects compared to retrofit projects which do not change the input fuel. This is not applicable to installations that form part of the fuel cycle (e.g. gas processing facilities). |
| Biomass leakage | CCS projects utilising biomass either straight firing or in co-firing must account for leakage due to biomass use, covering:<br>• Emissions from fossil fuel combustion in the biomass supply chain<br>• Emissions arising from offsite preparation of the biomass<br>• Emissions arising from fossil fuel combustion at other facilities<br>Emissions of $CH_4$ arising from anaerobic decay of biomass are excluded for reasons of conservativeness.<br>The accounting methodology must be based on the existing methodology outlined in ACM0006. |
| Enhanced hydrocarbon recovery | CCS projects including the application of $CO_2$-EHR techniques do not need to account for leakage arising from additional hydrocarbon production. However, one possible option might to require the project proponent to demonstrate the *environmental additionality* across the whole project life-cycle, in addition to financial additionality and barriers tests (see *Section 5.3.2*). |

| Issue | Approach |
|---|---|
| Additional material consumption | CCS projects should not account for leakage arising due to materials consumption as these cannot be easily calculated. This would likely require a full analysis of various manufacturing and/or fabrication processes related to the CCS project, which would be extremely complex to account for. Precedents in the CDM suggest that these emissions be excluded from leakage calculations. |
| Project lifetime issues | CCS project proponents could be required to demonstrate the environmental additionality of the proposed project across its full life-cycle. This would allow emissions beyond the last crediting period to be taken into account on decisions relating to project Registration. Where the project is unable to demonstrate environmental additionality, then the project could be considered as not eligible for CDM Registration. |
| Increased electricity consumption | CCS projects are likely to increase levelised generation costs at power plants, which in turn will increase electricity prices. This could lead to a decrease in electricity consumption. This form of *negative* leakage should not be accounted for in a CCS project.<br>Although CCS projects involve the monetisation of stored $CO_2$, which could create a perverse incentive for profligate electricity use, the differential between specific operating costs and specific revenues is unlikely to less than one [< 1] i.e. lower operating costs than specific revenues. |

# 7 PROJECT EMISSIONS

## 7.1 BACKGROUND

Under the CDM, project emissions can be defined as:

> *…emissions of greenhouse gases occurring inside the project boundary under the control of project participants, and which are significant and reasonably attributable to the CDM project activity* (1).

CCS projects, by definition, involve the long-term reduction of $CO_2$ emissions at source through capture, transport and injection of the emissions source into secure underground geological formations.

However, new types of emission sources are created as a consequence of a CCS project which will need to be accounted for as project emissions in a CCS CDM project activity. Sources of emissions include:

- *Combustion emissions* arising from the energy (steam, electricity) used to capture, transport and inject $CO_2$;
- *Fugitive emissions* arising across the CCS chain from the source to the point of injection;
- *Fugitive emissions* from seepage, if any, from the underground storage site, and
- *If* the project involves Enhanced Hydrocarbon Recovery (EHR) then the combustion emissions associated with the additional energy required to operate the EHR operation, plus any fugitive emissions arising from breakthrough $CO_2$ that re-emerges with the additional hydrocarbons produced.

Project emissions, therefore, must encompass all emissions that arise as a consequence of the project inside the project boundary (as outlined in *Section 3*).

Since in most cases the baseline for the CCS project is assumed to be the underlying activity without the application of CCS, then the project emissions outlined above do not affect the baseline since they only occur as a result of carrying out the CCS project activity. However, care must be taken when designing an accounting methodology to avoid double counting of emissions in both the baseline and as project emissions (in particular with regards to the energy penalty associated with powering a capture plant which may or may not be present in the baseline (2)).

A brief review of the different sources of project emissions in a CCS project is provided below.

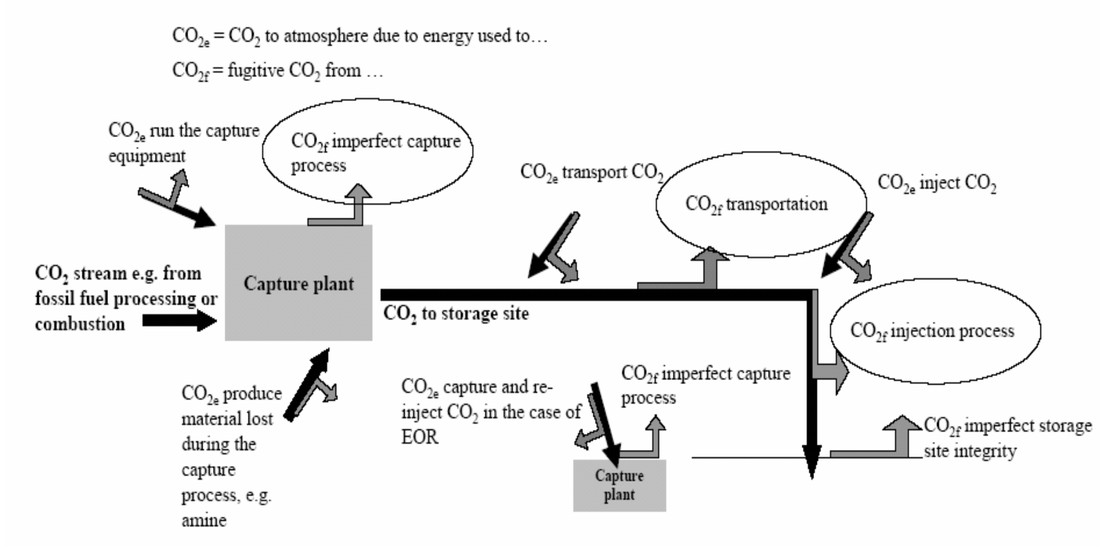
(1) This is the author's definition.

(2) For gas processing and LNG plants, as outlined previously, $CO_2$ capture will be an integral part of many plants in the baseline scenario, but this will not be the case for power plants.

## 7.2 *SOURCES OF EMISSIONS ACROSS A CCS PROJECT*

Emissions sources across a CCS chain have been summarised by Haefeli *et al* (2003) as shown below (*Figure 7.1*).

***Figure 7.1 Potential sources emissions to be monitored across a CCS chain***




Source: Haefeli, S., Bosi, M., and C. Philibert. *Carbon Dioxide Capture and Storage Issues – Accounting and Baselines under the United Nations Framework Convention on Climate Change.* IEA Information Paper, International Energy Agency, May 2003.

These are reviewed further below.

### 7.2.1 *Fugitive emissions*

Fugitive emissions of $CO_2$ could occur as part of routine *operational* activities involved with CCS. Reasons might include:

- inefficiencies and imperfections in $CO_2$ capture from the flue gas stream;
- emissions from solvent stripping operations, including imperfect stripping of the solvent;
- pipeline maintenance, repair or blowdown;
- venting due to overpressure in the pipeline or injectivity problems at the storage facility, and;
- inefficiencies and imperfections in $CO_2$ capture and reinjection at the extraction wellhead in EHR activities.

Other sources of fugitive emissions could include *background* emissions due to:

- leaking seals on blowing equipment required to force the flue gas into the adsorption tank;
- leaking seals on solvent stripping tanks;
- leaking seals on compression equipment at the pipeline head;
- pipeline fracture or rupturing;

- leaking seals on pipeline joints and pipeline booster stations;
- leaking seals on injection wellhead compressors, and;
- leakage from improperly sealed injection wellheads.

These emissions can be effectively calculated by conducting a mass balance across the CCS project chain using high quality (fiscal) metering data and gas analysis.

### 7.2.2 *Seepage from storage reservoirs*

Post-injection *seepage* of $CO_2$ back to the atmosphere from the storage site can potentially occur through subsurface processes such as diffusion through caprock or migration along fault lines, fissures or operational or abandoned wells. The capacity for long-term storage depends strongly on the specific characteristics of the storage reservoir into which the $CO_2$ is being injected. Although short-term leakage could occur in some storage sites during early phases of injection due to changing parameters in the reservoir such as pressure, properly selected reservoirs should be able to store $CO_2$ securely for very long periods of time. Certain unforeseeable events could – of course – potentially lead to large-scale release of $CO_2$ from a storage reservoir (e.g. unanticipated seismic activity).

In the context of the CDM, there are three key strands to consider for storage site emissions:

i) *Short-term potential emissions* occurring within the CDM crediting period, which can be accounted for as project emissions;
ii) *Short-term potential emissions* occurring after the end of the CDM crediting period, but before the CCS operation is terminated; and,
iii) *Long-term potential emissions* that could occur some time in the distant future following decommissioning of the $CO_2$ storage project.

Although emissions occurring inside the crediting period (type *i)*) can be dealt with in same way as in conventional CDM project accounting methodologies (i.e. deducted from the baseline as project emissions), seepage emissions of type *ii)* and *iii)* present the greatest challenge to developing accounting methodologies for CCS projects; this is essentially what is termed as the *permanence* issue. A more detailed discussion of approaches to handling permanence is provided in the next Section (*Section 8*), and is not considered further here.

Emissions from $CO_2$ storage sites can be detected and estimated by employing a range of above-ground and subsurface monitoring techniques, as outlined below (*Section 9*).

### 7.2.3 *Indirect emissions*

These relate to those emissions created by a CCS project, but actually occur outside its immediate boundaries. Principally these relate to any imported electricity or materials used for the activity, and will include:

i) Bought-in grid electricity for compression at booster stations along the pipeline or cooling of $CO_2$ for cryogenic ship transport, and for injection of the $CO_2$ at the storage reservoir;
ii) There could be additional energy associated with the manufacture, distribution, and disposal/incineration of $CO_2$ stripping equipment and agents, which would not have occurred in the absence of the activity.

With regards to type *i)* indirect emissions, these must be measured and calculated as project emissions within a CCS accounting methodology. Emissions associated with imported grid-electricity will need to be measured based on the amount of electricity consumed multiplied by the grid-average emissions factor for the grid from which electricity is taken. Combustion emissions associated with the direct use of other fuel types (e.g. gas for gas compressors; marine diesel) must also be measured and accounted for as project emissions.

With regards to type *ii)* indirect emissions, these should not be accounted for within the project accounting methodology (see *Annex C*).

# 8 PERMANENCE

## 8.1 BACKGROUND

Whilst permanence has been raised as a key issue for considering CCS as a CDM project activity, there is presently no official definition of permanence. In a recent presentation by the UNFCCC Secretariat, permanence was described as:

> *A qualitative term to characterize whether the carbon dioxide removed stays out of the atmosphere for a long time. Not defined in 19/CP.9 and Dec 17/CP.7. Dec 19/CP.9 defines how to address non-permanence* (1).

A definition has also been proposed by the authors, as follows:

> *…the ability of a CDM project activity to achieve long term reductions in emissions of greenhouse gases to the atmosphere below levels that would occur in the absence of the project activity*

CCS projects could, in some cases, experience re-emergence of a fraction of the $CO_2$ back to the atmosphere some time in the future, and as such pose challenges for accounting in emissions trading schemes.

## 8.2 METHODOLOGICAL ISSUES

The essence of the problem is whether rewards are provided today for emissions that might occur in the future, and whether there is a mechanism to suitably account for these future emissions. Furthermore, there are several other issues which affect the way in which permanence is considered, including:

- It is unclear what constitutes a long-period of time, or permanent emissions reductions in the context of CCS projects and climate change mitigation (2);
- It is unclear how to account for these emissions, particularly as CCS projects are widely agreed to present emission reductions at source (3);
- It is unclear whether it is truly feasible to try and attach present day values to emissions that may occur 1000's of years into the future, if ever.
- It is unclear on what basis the permanence issue should prevent CCS being recognised an emissions mitigation technology.

(1) Presentation by Sudhir Sharma, UNFCCC Secretariat, 2nd IEA GHG workshop on CCS in the CDM, Vienna, 7th August 2006.
(2) Many interpretations of permanence have revolved around the figure of 1000 years cited in the IPCC Special Report on Carbon Dioxide Capture and Storage (2005). The report proposes that *"..the fraction retained in appropriately selected and managed reservoirs is very likely to exceed 99% over 100 years, and likely to exceed 99% over 1000 years"*. However, these figures are principally a statistical quotient developed to describe storage across a global portfolio of sites. This is based on the principle that most sites won't leak if correctly selected and managed, but some might leak due to stochastic events e.g. well-bore failure etc.
(3) As opposed to sink enhancement projects, which are subject to temporary crediting. Views based on SBSTA24 workshop on CCS in the CDM.

In many ways, the argument is theoretical in nature, primarily as today's situation for nearly all fossil derived $CO_2$ sources is 100% impermanence i.e. 100% of emissions are released directly to the atmosphere. Furthermore, it is impossible for all stored $CO_2$ to be released back to the atmosphere under nearly any circumstance because pressure equilibrium will be reached well in advance of all the $CO_2$ being released i.e. the motive force pushing $CO_2$ from storage formations will be diminished prior to all the $CO_2$ being released. Moreover, permanence of geologically stored $CO_2$ is a function of good site selection, risk management and appropriate closure, and not an inherent feature of all projects.

The proceeding Section outlines some thoughts and perspectives on the permanence issue [(1)].

### 8.3 *APPROACHES TO ACCOUNTING FOR PERMANENCE*

The handling of permanence in CCS operations is a critical factor in maintaining the environmental integrity of the CDM and international emissions trading. If seepage of $CO_2$ occurs during the crediting period, these emissions can be monitored and reported as *Project Emissions*, and accounted for by deducting the amount from the project *Baseline* for that year as outlined above (*Section 7*). This issue is considered to be consistent with the modalities and procedures for the CDM, and is not considered further here

If seepage from the storage reservoir occurs after the crediting period, then liability for the emissions needs to be effectively managed in order to maintain the environmental integrity of the CDM over the longer-term.

Seepage emissions beyond the crediting period could be managed within the CDM by either:

i) Creating longer-term liability for project developers/operators to buy GHG compliance units such as CERs in the event of seepage emissions as part of a CCS project approvals process (e.g. a permitting/licensing regime for $CO_2$ storage operations which includes an offset obligation);
ii) Flagging CCS-specific CERs or issuing temporary CERs etc which would be cancelled and require replacement, *pro rata*, in the event that seepage occurred. This would pass liability for seepage emissions on to the buyer of the CERs ("buyer liability"); or,
iii) Applying a default or discount factor to account for future seepage emissions so that either a portion of CERs are not issued, a portion are set aside in a credit reserve, or a portion of the revenue from CERs sales is set aside in a contingency fund etc. This could serve to essentially cap liability for all actors in the market at the chosen default or discount rate.

Whatever the approach, the most important consideration is that the structure of liability provisions need to be practical and predictable for both project developers and the wider GHG market.

(1) These broadly align with those views presented by IETA members to SBSTA24 in May 2006.

Approach *i)* is considered to be most appropriate as it decouples the liability for any seepage emissions from the CERs issued from any project, meaning that CERs from CCS projects would be fungible with other commodities in the GHG market. Moreover, liability for any seepage emissions would lie in the hands of those most able to take actions to rectify the seepage i.e. the project developer/operator.

Approaches *ii)* and *iii)* could create difficulties for inclusion of CCS in the CDM: creating flagged or temporary CERs will affect their fungibility in GHG markets, creating marketability issues, whilst; applying generic discount or default factors is likely to be a highly complex and contentious process as there is no scientific basis for setting such factors (1). Furthermore, approach *ii)* could also create integrity problems for the CDM, as liability would essentially be capped at the discount rate selected, and it is unclear how any seepage emissions greater than discount/default factor applied would be handled.

In the context of approach *i)*, the evolution of a robust permitting/licensing process for $CO_2$ storage sites should be a critical factor in ensuring appropriate site selection, as well as site operation, decommissioning, remediation, liability and longer-term stewardship arrangements etc. for all CCS projects across any jurisdiction, regardless of whether the project is a CDM project or not. H

However, recognising the need to maintain the environmental integrity of the CDM, it is suggested that a $CO_2$ storage site permit/license for a CCS CDM project, and the associated monitoring and remediation plan, include a commitment for the operator to make up the level of any seepage emissions calculated to have occurred at that time i.e. the operator would be liable (subject to *force majeure* qualifications) to purchase CER equivalent compliance units equal to the amount of seepage emissions determined to have occurred (i.e. a legally binding offset obligation). In order for this approach to work, the operator would need to manage contingent liability for any seepage. This could be achieved through establishment of *inter alia*: insurance, indemnities, escrow or contingency funds, and/or credit reserves.

## *8.4 COMMERCIAL APPROACHES TO MANAGING LIABILITY*

The process for establishing the mechanism for managing contingent liability for remediation of *potential* future emissions – including offsetting – could either be:

- established multilaterally via a standardised CDM approach for all projects within an approved CDM methodology. This may need to be in the form of guiding principle rather than prescriptive approaches, taking into consideration the difficulties in developing generic factors (e.g. the scientific challenges presented in trying to establish generic discount or default factors for CCS projects); or,

(1) The IPCC SRCCS highlights that: "Today, no standard methodology prescribes how a site must be characterized. Instead, selections about site characterization data will be made on a site-specific basis, choosing those data sets that will be most valuable in the particular geological setting." IPCC SRCCS, Chapter 5, Section 5.4.1.1, pg. 225.

- negotiated bilaterally with the host country regulator prior to project approval via the Environmental Impact Assessment part of a CDM Project Design Document, which should form part of the overall storage site permitting/licensing requirements. In practice, this could take the form of an agreed *de facto* default factor where CERs are set aside in a credit reserve, a share of the proceeds of CER sales are placed in a ring-fenced contingency fund, or by insurance providers pooling risk across a portfolio of projects (e.g. through issuance of bonds).

For either process, in the absence of certainty over future CER prices, there is a critical need to cap the contingent liability on the requirement to purchase any CERs in the event of seepage emissions. Without a cap on liability, investment decision-making would be impossible as the project would involve the taking-on of unquantifiable contingent liabilities, which would be commercially unworkable.

## 8.5 HOST COUNTRY APPROVAL AND REGULATORY REQUIREMENTS

In the context of the bilateral negotiation process, national governments may adopt a mandatory requirement for the undertaking of an EIA for CCS projects - including CCS projects in the CDM. The EIA would include full consideration of site selection and characterisation, monitoring, remediation, decommissioning and longer-term stewardship (1). In order to ensure robustness of such a process, the CDM EB and associated bodies could develop guiding principles for undertaking EIAs for CCS projects within the CDM, with reference to best practice principles for site selection, operation, monitoring, decommissioning, longer-term stewardship and remediation (2). In this respect, there is likely to be capacity building needs to ensure that an effective arrangement is in place in host countries. For example, the establishment of a CCS Expert Panel (either independent from or within the CDM EB process) setting out and disseminating industry best practices to support capacity-building in countries that need the expertise, would serve to enhance the robustness of CCS project development around the world.

Host country approval of the EIA, coupled with validation of the PDD and EIA by a DOE accredited specifically to validate CCS projects, could provide an approvals mechanism to ensure appropriate $CO_2$ storage site selection consistent with the modalities and procedures of the CDM.

(1) Currently a precedent for $CO_2$ storage site approval is that of the Gorgon Project in Western Australia, where an environmental impact assessment (EIA) and an environmental impact statement (EIS) have been produced. The Gorgon EIS outlines a range of issues relevant to the proposed CCS part of the project, including site selection criteria, site characterisation, permanence, stewardship and liability. See www.gorgon.com.au

(2) An EIA would require project developers to outline how they would manage any environmental impacts associated with a CCS projects. One of these impacts would include 'global environmental impacts' of seepage emissions, to which the developer could commit to remediate this damage by purchasing GHG compliance units such as CERs. Also in this context, a useful guide to the types of principles that could be developed have been produced for CCS in the EU ETS. See Zakkour, P. *et al*. UK DTI Report R277: Developing Monitoring Reporting and Verification Guidelines for $CO_2$ Capture and Storage in the EU ETS. 2005. Environmental Resources Management (ERM).

## 8.6 *APPROACHES FOR HANDLING PERMANENCE IN CCS CDM PROJECTS*

On the basis of the discussion outlined above – and supported by the approach outlined in the 2006 GHG guidelines (*Sections 3.3* and *9.3*) – the level of permanence achieved by a CCS project is an inherent function of good site selection, application of risk assessment, risk management practices (including an effective sub-surface monitoring programme), remediation commitments, abandonment and liability procedures, and offsetting of any emissions occurring beyond the crediting period.

Consequently, permanence is really a function of regulation, and therefore all these components must form part of an appropriate regulatory regime for CCS projects, regardless of whether they are CDM project activities or otherwise. Presently, in the absence of any international regulatory standards for CCS projects, the CDM must ensure a level playing-field for all potential CCS CDM projects by requiring adherence to these principles as a pre-requisite for registration as CDM project activity.

# 9 MONITORING METHODOLOGY

## 9.1 BACKGROUND

According to the *Technical Guidelines for the Development of New Baseline and Monitoring Methodologies* (1), a CDM monitoring methodology needs to:

> *…provide detailed information on how to establish the monitoring plan related to the collection and archiving of all relevant data needed to:*
>
> *(a) Estimate or measure emissions occurring within the project boundary,*
> *(b) Determine the baseline emissions, and*
> *(c) Identify increased emissions outside the project boundary.*

Furthermore, the monitoring methodology should

> *…provide a complete listing of the data that needs to be collected for the application of the methodology. This includes data that is measured or sampled and data that is collected from other sources (e.g. official statistics, expert judgment, proprietary data, IPCC, commercial and scientific literature, etc.).*

For a CCS project as a CDM project activity, the monitoring methodology must be designed to determine four key components of the project:

i) Monitoring of various energy and $CO_2$ flows within the project boundary (see *Section 3*) which will form the basis upon which to measure *project emissions* for above ground installations related to the project (see *Section 7*);
ii) Monitoring of various energy and $CO_2$ flows within the project boundary, which will form the basis upon which to measure *baseline emissions* using an *ex post* approach (i.e., how much $CO_2$ was produced *before* it was captured, transported and stored under the CCS project; see *Section 7*);
iii) Monitoring of various data and/or use of reference or emissions factor based approaches to estimate *leakage emissions* outside of the project boundary that are reasonably attributable to the project activity (see *Section 6*); and,
iv) Monitoring of various parameters within the subsurface component of the project boundary in order to estimate the *permanence* of storage i.e. that the $CO_2$ remains in the reservoir, and to estimate whether there has been any *seepage* from the reservoir i.e. re-emergence of $CO_2$ back to the atmosphere from the geological storage site or surrounding media. This component of the monitoring methodology is relevant to:
    - accounting for project emissions during the CDM crediting period for the project activity;
    - accounting for emissions from the storage site beyond the CDM crediting period;

(1) Available from the UNFCCC, at http://www.unfccc.int/cdm

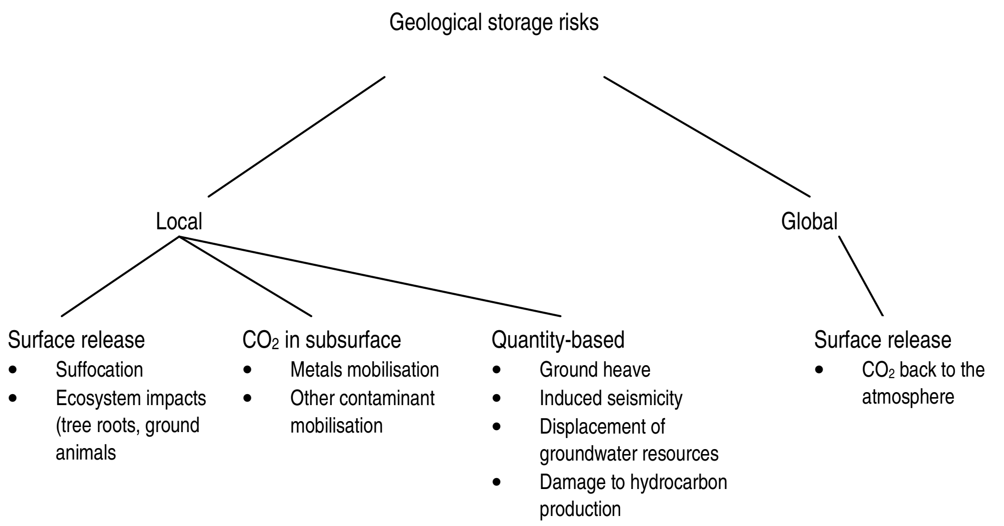
- inclusion of emissions estimates in National Greenhouse Gas Inventories; and,
- ongoing management of the risk of potential localised health, safety and environmental impacts posed by seepage from the storage site.

Components *i)*, *ii)* and *iii)* relating to the project, baseline and leakage emissions do not present new challenges in the context of CDM methodologies. Issues and approaches to calculating these parameters have been discussed in previous sections of this report, and therefore are not considered further in this *Section*.

Component *iv)* relating to estimation of emissions from the sub-surface presents new issues in the context of a CDM monitoring methodology, and forms the focus of the remainder of this *Section* (1).

The objectives of a $CO_2$ storage site monitoring plan is two-fold, dictated by the risks posed by the operation, as summarised below (*Figure 9.1*). In this context, the primary concern for the CDM component is the *global* branch of the taxonomy diagram. However, surface release is also a *local* environmental, health and safety concern, and thus the objectives should be combined in the monitoring plan. Indeed, in the absence of the CDM, health and safety concerns would dictate that surface release be monitored and reported.

***Figure 9.1 Taxonomy of possible risks of geological storage***




Source: Wilson, E., and D. Keith. *Geologic Carbon Storage: Understanding the Rules of the Underground.* In Gale, J and Y. Kaya (eds). *Proc. Of the 6th Int Conf. on Greenhouse Gas Control Techs (Vol I).* October, 2003. Pergamon

(1) It is important to note that there are close interactions between the design of the monitoring methodology, and definition to the project boundary, as reviewed in *Section 3*.

## 9.2 METHODOLOGICAL ISSUES

The key issues to consider in the design of CDM CCS monitoring methodology include:

i) *The project- specific characteristics of any sub-surface monitoring plan*: Because of the heterogeneous nature of the sub-surface environment, each CCS CDM project activity will need a project specific monitoring plan and technologies tailored to the characteristics of the primary storage formation(s) and the surrounding environment, and the inherent risk of seepage.
ii) *The need to take a risk-based approach*: Different $CO_2$ storage formations will pose different seepage risk potential, based on the nature of the primary $CO_2$ storage containment complex, potential seepage pathways in the zone around the primary containment complex, the surrounding environment, the attendant magnitude of potential exposure, and sensitivity of potential receptors.
iii) *The range of monitoring techniques available*: There are a range of sub-surface monitoring techniques that are able to detect the presence and vertical and lateral spread of $CO_2$ in the subsurface (e.g. 2-D, 3-D and time lapse (4-D) seismic) and migration and seepage from the primary containment complex (within limits of detection; e.g. soil gas and groundwater monitors, accumulation chambers, infra-red laser gas analysis).
iv) *The frequency of application*: Some techniques may involve continuous monitoring, whilst others may only be periodically applicable (e.g. environmental constraints may mean that seismic surveys are only carried out every 3-5 years or so);
v) *The embryonic and innovative nature or monitoring techniques:* Many monitoring techniques are presently under refinement, with new concepts and applications also being under development at the time of writing;
vi) *The aim and objective of the monitoring plan:* The key objective of a monitoring plan for a $CO_2$ storage site in the CDM is to account for seepage of $CO_2$ back to the atmosphere, both during the CDM crediting period (to account for emissions as project emissions), and beyond the CDM crediting (to account for offsetting post crediting). Both elements will be required in order to allocate seepage emissions in the host-country National Greenhouse Gas inventory. A monitoring plan for a $CO_2$ storage site must also be designed in order to manage potential environmental, health and safety risks posed by seepage from the storage site;
vii) *The 2006 IPCC Guidelines for National Greenhouse Gas Inventories:* The 2006 guidelines include guidance on accounting for emissions from $CO_2$ storage.
viii) *The need for quality assurance and quality control*: Any proposed $CO_2$ storage complex monitoring plan will require careful assessment by suitable expertise. Sub-surface $CO_2$ monitoring is an emerging area of study, and specific worldwide expertise is limited, although oil & gas exploration activities have some important analogues.

To date, these issues have not been fully explored in the CDM. They must be addressed and dealt with in an acceptable manner in order to complete the process of elaborating a new methodology for CCS under the CDM.

*Annex D* provides a brief review of the two sub-surface monitoring methodologies submitted to date (NM0167 and NM0168).

### 9.3 2006 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES

Details on the 2006 GHG guidelines were presented above (*Section 3.3*). The approach proposed by the IPCC confirms two key issues presented above, namely that:

- Site specific monitoring design will always be required as the suitability and efficacy of monitoring technologies can be strongly influenced by the geology and potential emission pathways at a specific site, and;
- Monitoring technologies are advancing rapidly, and good practice suggests that monitoring technology applications should be updated to keep abreast of developments.

In addition, the 2006 GHG guidelines also outline a multi-step process to compilation of the emissions inventory form $CO_2$ storage sites, as follows:

1. Identify and document all geological storage operations in the jurisdiction
2. Determine whether an adequate geological site characterization report has been produced for each storage site.
3. Determine whether the operator has assessed the potential for leakage at the storage site.
4. Determine whether each site has a suitable monitoring plan. This includes:
    a. Measurement of background fluxes at the storage site and potential emission points in the surrounding zone
    b. Continuous measurement of the mass of $CO_2$ injected
    c. Monitoring to determine emission from the injection system
    d. Monitoring to measure fluxes through the seabed or ground surface, including wells and springs
    e. Post injection monitoring
    f. Incorporation of improved monitoring techniques
    g. Periodic verification
5. Collect and verify annual emissions from each site.

With respect to the design of a CDM monitoring methodology for CCS project activities, the critical challenge is to operationlise Step 4 of the procedure outlined above, namely the design of an adequate monitoring plan. Following sections of this report set out a proposed design of a monitoring programme for a $CO_2$ storage site which is consistent with approach outlined in Step 4 (1).

(1) Note: Steps 2-3 have been considered in the discussion presented in Section 3, where the definition of a CCS project boundary is outlined.

## 9.4 *DESIGN OF A SUB-SURFACE MONITORING METHODOLOGY FOR CCS PROJECTS*

The key objectives of a $CO_2$ storage site monitoring plan are to:

- Detect the presence, location and migration paths of $CO_2$ in the subsurface in order to provide assurance regarding the permanence of storage; and,
- Detect the seepage and the effects thereof of $CO_2$ migrating from the primary $CO_2$ containment complex, and potentially re-emerging at the surface i.e. atmospheric release.

The heterogeneity of the sub-surface means that a bespoke approach will be required based on the particular characteristics of an individual site, covering the site specific potential risk of $CO_2$ seepage, the number and size of potential pathways and therefore the potential magnitude of seepage events, and the sensitivity of receptors in the zone surrounding the storage site.

Consequently, as suggested in previous *Sections*, a CDM monitoring methodology for the sub-surface will have to be dynamic enough to be applicable to a range of different CCS projects. The alternative would be the development of a highly prescriptive approach, which in essence would mean that under the current CDM regime, a new CDM monitoring methodology would have to be proposed for every planned CCS project in the CDM.

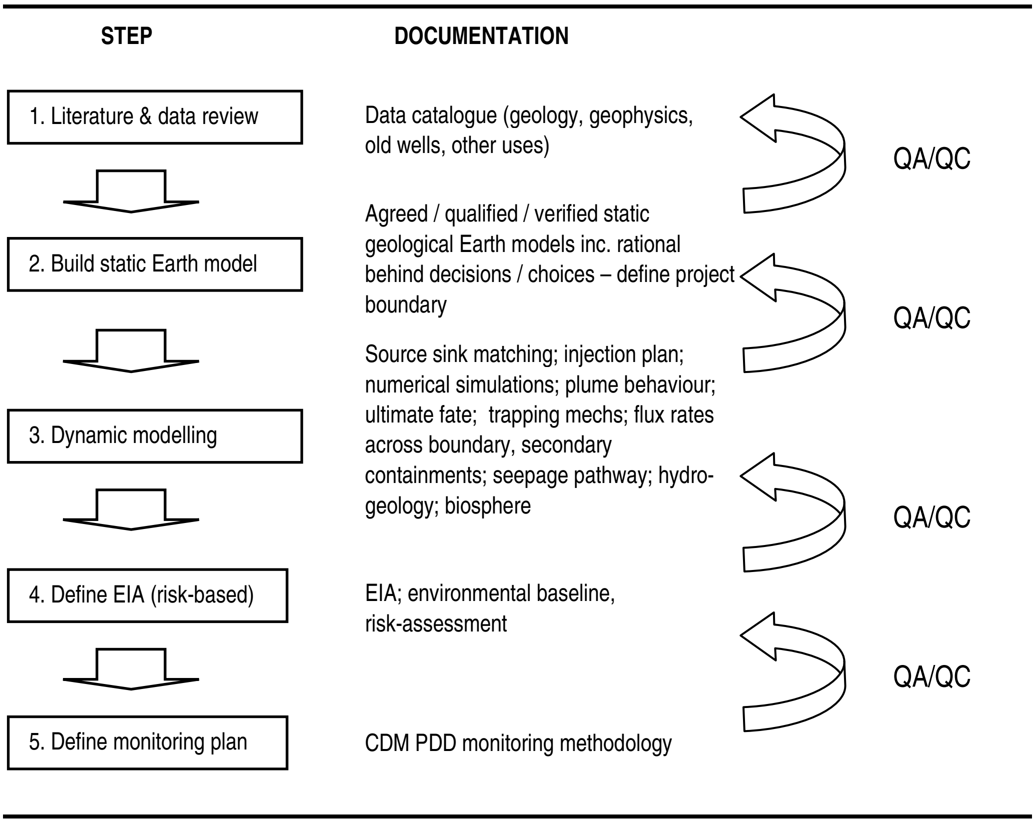
Therefore, an appropriate methodology needs to outline a common set of principles and procedures which can be adopted by project proponents in order to arrive at a consistent design philosophy for a $CO_2$ storage site monitoring plan; this will be driven by a comprehensive storage site performance assessment, as outlined in *Section 3* and the following *Sections*.

A further key component in the design of the methodology will be the rigorous application of appropriate quality assurance and quality control procedures (QA/QC). QA/QC will serve to minimise the risk of selecting poor storage sites, and also the implementation of inappropriate monitoring plan.

As such, the following section highlights the key steps, information requirements, and procedures relevant to the design of a CCS CDM monitoring methodology for the $CO_2$ storage site, based around a comprehensive storage performance assessment.

The proposed approach is summarised below (*Figure 9.2*).

*Figure 9.2 Key steps in designing a $CO_2$ storage site monitoring plan*




### 9.4.1 *Step 1 - Literature and Data review*

The preliminary step in identifying a $CO_2$ storage site is the collection and collation of various subsurface literature and data sources. These data and literature can be used to identify potential storage formations in the province under study. Potential storage formations (1) will be sedimentary structures that indicate the presence of potential $CO_2$ trapping mechanisms (physical / structural trapping; mineral trapping; hydrodynamic trapping etc) at sufficient depth (generally >800m, although this will partially be temperature dependent). This will be based on the following types of sub-surface information:

- Geology (stratigraphy, petrology, mineralogy, faults, folding, heterogeneity etc);
- Geochemistry (dissolution rates, mineralisation rates);
- Geomechanics (permeability, fracture pressure);
- Hydrogeology;
- Temperature (phase state);
- Pressure (phase state);
- Vertical and lateral sealing (physical trapping);
- Caprock integrity (basal unit information such as pore size, capillary entry pressure, facies change etc.)
- Presence of man-made "bridges" (wells, mine shafts etc)

(1) It is probably more sensible to think in terms of storage complexes, a paradigm that includes consideration of the surrounding strata, and helps to frame ideas around potential migration pathways and secondary containment formations.

Key data sources might include:

- Geological maps;
- Regional geological reports;
- Well core analysis data;
- Well logs;
- Reservoir fluid analysis;
- Injection tests;
- Geomechanical tests;
- Seismic reports and data;
- Other province level data (e.g. regional seismicity) etc.

Suitable quality data of this type will assist in provisional screening of potential storage sites.

Initial environmental, health and safety considerations will also need to be made at this stage, as these may preclude certain storage locations. Economic considerations will also need to be taken into account in terms of:

- Proximity to valuable natural resources (potable groundwater, hydrocarbons etc.)
- Proximity to the $CO_2$ source which is planned for storage;
- $CO_2$ delivery rate;
- $CO_2$ purity;
- Permeability / formation(s) injectivity;
- Life span (i.e. ultimate storage capacity);

Where insufficient geological and geophysical data is available, then additional exploration activities may be necessary, involving acquisition of new seismic data, and/or the drilling of exploration wells, injection testing etc.

### 9.4.2 *Step 2 – Build static Earth model(s) (scenarios)*

Using the data collected in Step 1, 3-D static geological Earth model(s) will need to be built in computer reservoir simulators. The static geological Earth model(s) will serve to characterise the potential site in terms of:

- Geological structure of the physical trap;
- Geomechanical properties of the reservoir;
- Geochemical properties of the reservoir;
- Presence of any faults or fractures;
- Fault / fracture sealing;
- Pore space volume;
- Porosity etc.

Essentially, the building of a 3-D static geological Earth model combines the parameters described in Step 1 into a set of unified models of the geological reservoir and surrounding domains.

In reality, there will be degree of uncertainty about each of the parameters used to build the model, and a range of scenarios for each parameter should be contained in the model, and appropriate confidence limits attached.

All rationale and assumptions used to build the model must be appropriately documented, and should ideally be agreed through expert panel decision-making (subject to appropriate QA/QC; see below) before proceeding to Step 3.

Where agreement on the rationale and confidence assumptions cannot be reached, there may be a need to acquire additional data to improve data resolution etc i.e. return to Step 1

### *9.4.3 Step 3 – Undertake dynamic modelling*

Dynamic modelling involves the running of various time-step simulations of $CO_2$ injection into the 3-D static geological Earth model(s) in the reservoir simulator constructed under Step 2. Factors to consider will include:

- Injection rates and $CO_2$ properties (based on source characteristics);
- The efficacy of coupled process modelling (i.e. the way various single effects in the simulator(s) interact);
- Reactive processes (i.e. the way reactions of the injected $CO_2$ with *in situ* minerals feedback in the model);
- The reservoir simulator used (multiple simulators may serve to validate certain findings);
- Short and long-term simulations (to establish $CO_2$ fate and behaviour over decades and millennia)

The dynamic modelling should be able to provide insight to:

- The nature of $CO_2$ flow in the reservoir;
- Storage capacity and pressure gradients in the primary containment complex;
- The risk of fracturing the storage formation(s) and caprock;
- The point when overspill may occur (in physical traps);
- The rate of migration (in open-ended reservoirs);
- Fracture sealing rates;
- Changes in formation(s) fluid chemistry and subsequent reactions (e.g. pH change, mineral formation, and inclusion of reactive modelling to assess affects);

Multiple simulations will be required, based on altering parameters in the static geological Earth model(s), and changing rate functions and assumptions in the dynamic modelling exercise (sensitivity analysis).

*Risk assessment*

A key component of the dynamic modelling exercise will to assess the potential risks (likelihood and consequences) posed by the storage operation, based on the scenarios generated in the modelling exercise. Application of appropriate simulation techniques and scenarios should allow provisional understanding of the:

- Potential seepage pathways;
- Potential magnitude of seepage events (flux rates);
- Potential receptors for seeped $CO_2$;
- Critical parameters affecting potential seepage (e.g. maximum reservoir pressure, maximum injection rate, sensitivity to various assumptions in the static geological Earth model(s) etc.);

These data can be used to assess the overall risk-profile of the project, and influence the framework of risk management measures and ultimately the decision as to whether to commence with the project. The data and outputs generated will also be used to inform an environmental, social, and health & safety impact assessment (ESHIA).

### 9.4.4 Step 4 - Define risk-based ESHIA

Based on the dynamic modelling exercise undertaken in Step 4, an assessment will possible of the potential environmental, health & safety risks posed by the storage operation [1].

The ESHIA will be based on detailed understanding of the:

- *$CO_2$ sources*: The storage site or potential secondary containment features in the storage complex from which $CO_2$ could migrate or seep to the surface;
- *Pathways*: The potential "bridges" (such as faults or abandoned wells) which could join the sources of $CO_2$ to the surface or other sensitive secondary containment domains (e.g. groundwater resources), and the modelled flux rate;
- *Receptors*: The environment and organisms that will potentially be exposed to the seeped $CO_2$, including consideration of potential maximum seepage rates, and the sensitivity of the receiving environment. This will need to include consideration of any future planned uses of the exposed zones.

The ESHIA should also outline how these potential risks will be managed, including a remediation commitment and plan in the event of seepage.

The ESHIA should also include appropriate commitments for post-closure monitoring, safe site abandonment, provisions for handling long-term liability, and inclusion of contingency measures (e.g. insurance, escrow fund) in order to ensure ongoing stewardship in the event of insolvency of the

(1) "Risk" here refers to the combination of the likelihood of certain events or incidents together with their consequence.

operator or transfer of liability to the host government (see *Sections 8.5* and *10.2.1*).

Part of the risk component also includes the potential impact (climate consequences) on the global atmospheric environment i.e. the risk of partially impermanent storage. As such, remediation commitment might also include commitment to make this damage by the purchase of appropriate GHG compliance units to offset these impacts (see *Section 8.3*).

The ESHIA issue is covered in greater depth below (in *Section 10.2.1*).

### *9.4.5 Step 5 - Design monitoring plan*

Dynamic modelling will serve to illustrate the following key facets of the storage site:

- $CO_2$ trapping mechanisms and rates (including spill points and lateral and vertical seals);
- $CO_2$ migration rates through the formation(s) (to illustrate when the $CO_2$ might reach the planned vertical and lateral edges of the defined $CO_2$ containment complex; see *Section 3.2*);
- Potential weak points in the overall containment system, and potential sealing mechanisms;
- Secondary containment systems in the overall storage complex;

These form the basis for the design of a monitoring plan that is able to detect the modelled/predicted seepage (most likely and worst case) and the effects thereof of $CO_2$ migrating from the target $CO_2$ containment complex, and potentially re-emerging at the surface.

Other elements of the monitoring plan may also include:

- Technologies which can provide a wide areal spread in order to capture information on any previously undetected potential seepage pathways (e.g. airborne remote sensing technologies); and,
- Technologies that can detect the presence, location and migration paths of $CO_2$ in the subsurface in order to provide assurance regarding the permanence of storage (e.g. seismic, well bore logs, gravity surveys etc);

In addition, continuous or intermittent monitoring of the following items must also be included:

- Fugitve emissions of $CO_2$ at the injection facility;
- $CO_2$ mass flow at injection wellheads;
- $CO_2$ pressure at injection wellheads;
- Chemical analysis of the injected material; and,
- Reservoir temperature pressure (needed to determine $CO_2$ phase behaviour and state);

*Elaboration of the monitoring plan in the Project Design Document*

The precise choice of technology employed should be based on best practice available at the time, and subject to change going forward (see *Section 10.5*).

As a minimum, project proponents should demonstrate in the CDM PDD, that all the technologies outlined in Annex 1 of Volume 2, Chapter 5 of the 2006 GHG Guidelines have been considered, and justification of selection [or not] of each should be provided. Additional technologies are likely to emerge in the intervening period between the publication of IPCC Inventory Guidelines, and project proponents should consider additional sources of best practice, such the *IEA GHG R&D Programme* monitoring tool (1).

The final monitoring plan should outline specific details in *Section D.2.1.2* of the PDD form including:

- Technology employed (2);
- Technologies excluded (non-exhaustive);
- Justification for technology choices;
- Monitoring locations and spatial sampling rationale;
- Frequency of application and temporal sampling rationale;

Project proponents should also provide an indicative assessment of the efficacy of the monitoring plan proposed, including assumed detection levels and evaluation of "important" or "significant" threshold levels in various sub-surface zones and domains.

## 9.5 QUALITY ASSURANCE AND QUALITY CONTROL

Each of the steps outlined above must be subject to appropriate quality control, preferably by the following in order of importance:

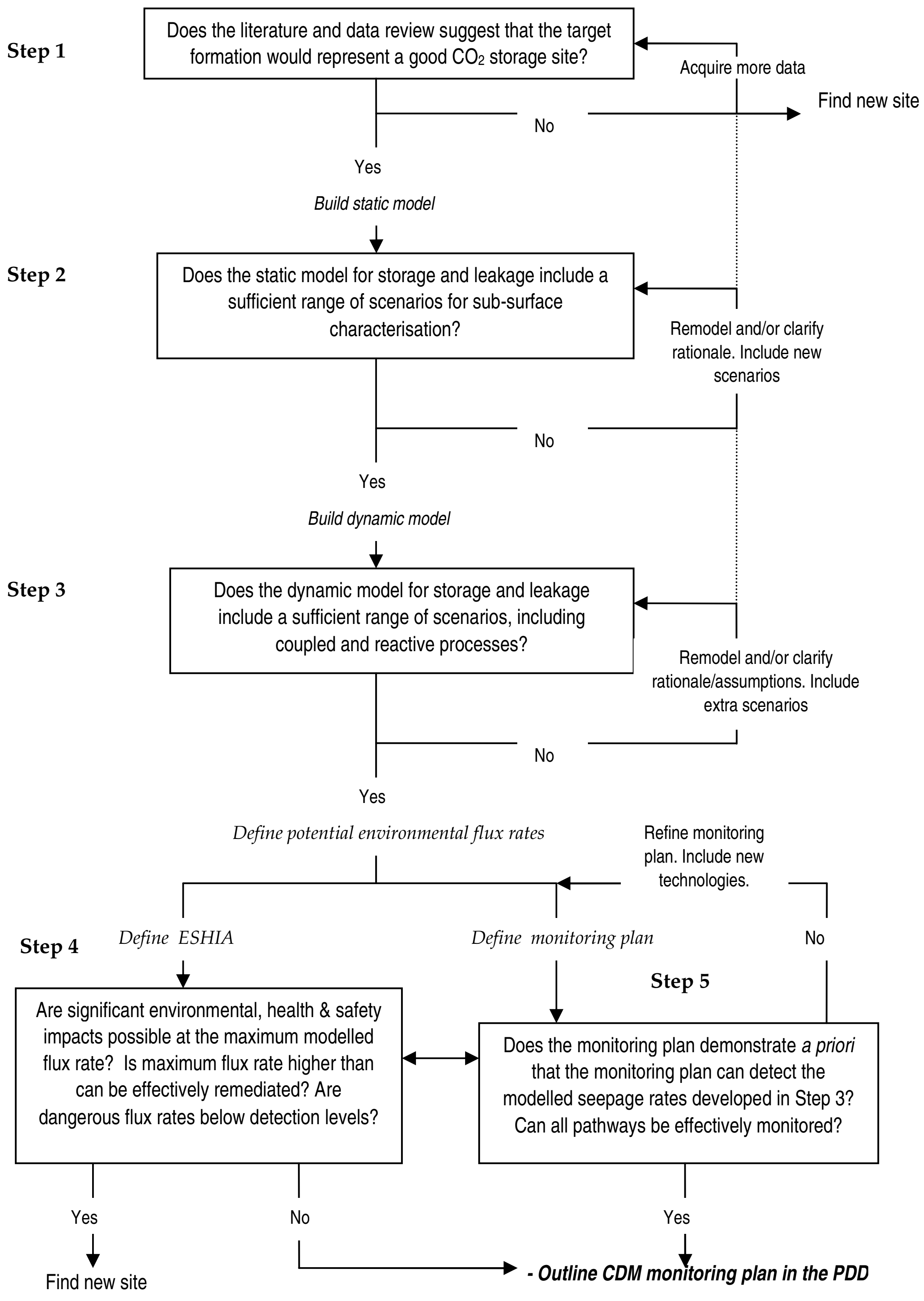
- Project proponent;
- Host country regulators; and,
- DOE validating the PDD.

A proposed schematic for the QA/QC procedure is outlined below (Figure 9.3).

(1) Available here: www.co2captureandstorage.info/co2monitoringtool

(2) In this context, specific notation for different monitoring technologies should be developed in order to assist PDD development.

*Figure 9.3 QA/QC procedure for storage site selection and monitoring plan*

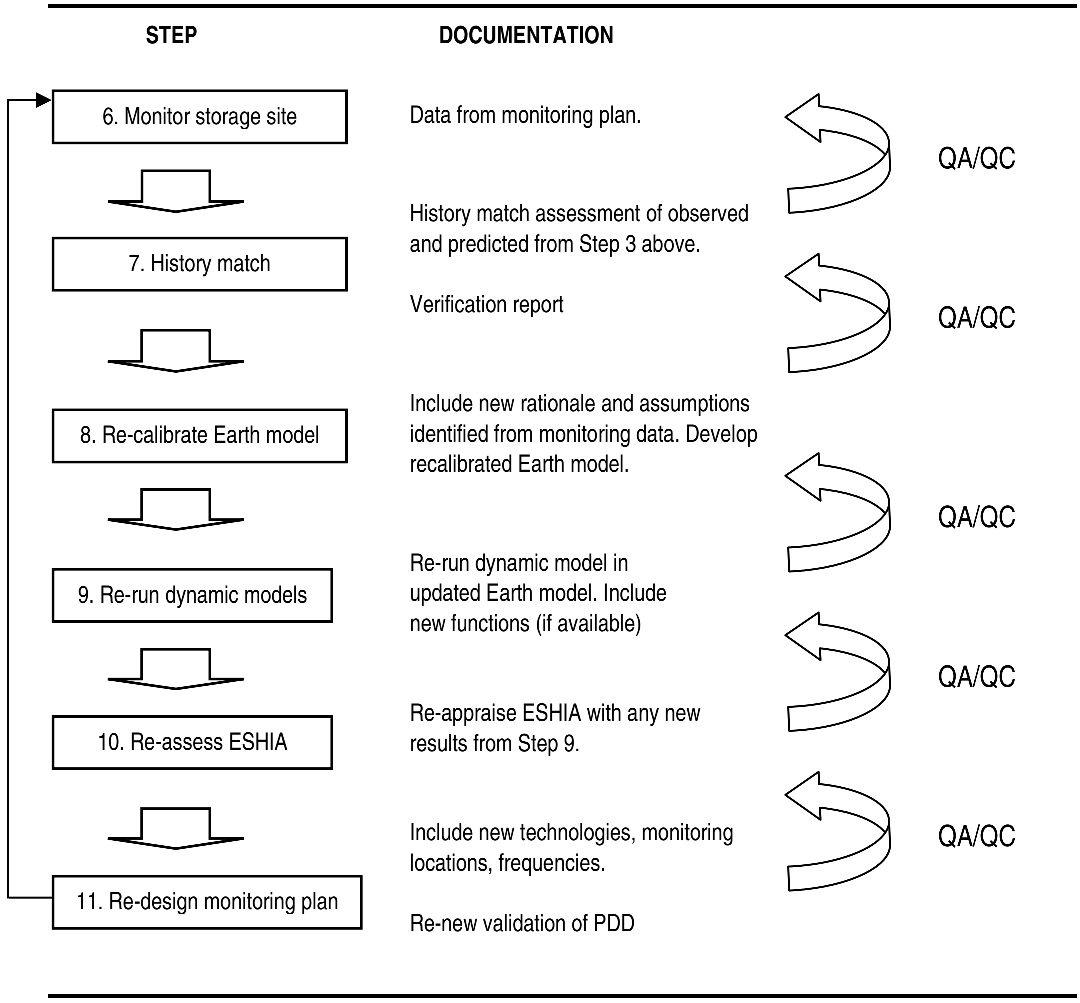



## 9.6 ADAPTING THE MONITORING PLAN POST-INJECTION

Even with the most rigorous of static and dynamic geological Earth model(s) design and analysis, deviations from predicted behaviour post injection can be expected. As such, it will important to adopt an adaptive learning process based around iterations of the procedure: model → predict → monitor → update → [repeat] etc.

As such the following additional steps are added to the sequence outlined above (*Figure 9.2*)

*Figure 9.4* ***Key steps in updating a $CO_2$ stroage site monitoring plan***




### *9.6.1 Step 6 - Collect monitoring data*

This involves the collection and collation of the data collected from monitoring.

### *9.6.2 Step 7 - History-match*

History-matching involves comparing observed results from the storage site monitoring with the behaviour predicted in dynamic Earth modelling undertaken in Step 3.

Appraisal and comparison of monitored behaviour will allow new assumptions to be developed about the characteristics of the sub-surface, based on the new data received. These can be used to re-calibrate the static geological Earth model(s), including new rationale, assumptions etc.

### *9.6.3 Step 8 - Re-calibrate static Earth model(s)*

The static Earth model(s) should be re-calibrated based in the results of history matching.

### *9.6.4 Step 9 - Re-run dynamic models*

New seepage scenarios and flux rates should be generated in the dynamic modelling exercise, based on the recalibrated geological Earth model(s) prepared in Step 8.

### *9.6.5 Step 10 - Re-assess environmental impacts*

The new scenarios produced in Step 9 should be used to re-assess the previous ESHIA prepared.

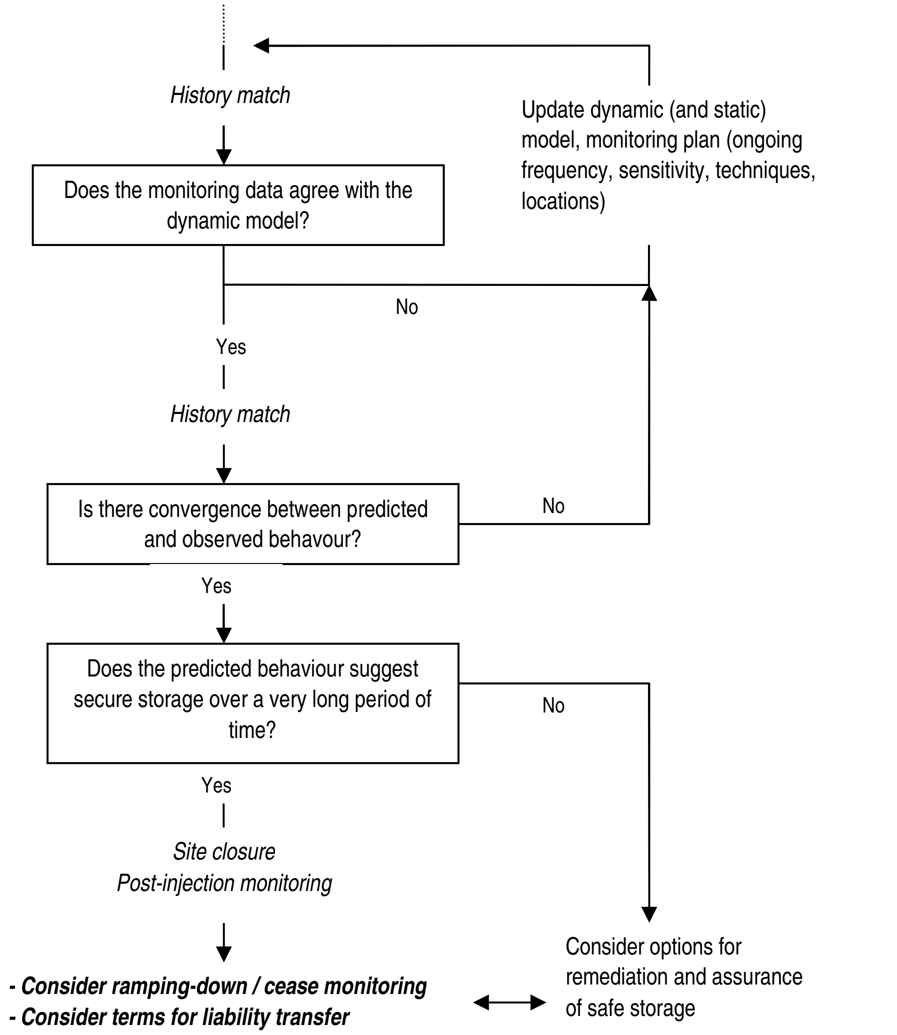
### *9.6.6 Step 11- Re-design monitoring plan*

The re-running of the dynamic models will generate new insights into the sub-surface characteristics of the storage containment complex and behaviour of the injected $CO_2$. Consequently, where new $CO_2$ sources, pathways and flux rates are identified, the monitoring plan may need to be adjusted according. This could serve to provide better resolution of observation, and better detection of migration and or potential seepage.

### *9.6.7 Step 12 - Reapply QA/QC*

Relevant parts of the QA/QC process outlined above will then need to be re-applied. In addition, other QA/QC requirements will be presented at this stage of the project, as outlined below (*Figure 9.5*).

*Figure 9.5 Additional QA/QC procedure for ongoing injection recalibration*




QA/QC will also involve indicatively verifying that the mass of $CO_2$ captured does not exceed the mass of $CO_2$ stored (according to injection records and detected from seismic surveys etc) plus the reported fugitive emissions in the inventory year. This is in accordance with the IPCC 2006 Guidelines.

## 9.7 LONGER-TERM STEWARDSHIP

Any CCS operation undertaken as a CDM project activity will require continued monitoring of the storage site beyond the end of the CDM crediting, as the site may either still be operating (1) or it is closed by the operator. In either case monitoring will be required to the point when certain performance criteria have been met post closure i.e. the sub-surface $CO_2$ plume has demonstrably reached a stable and secure state and the stored $CO_2$ can be reasonably expected to remain isolated from potential receptors for a very long-period of time. Reference is made to this condition in the proposed

(1) This might be the case for EHR projects, although for pure storage operations, in the absence of incentives beyond the crediting period, it is unclear whether operators would begin venting $CO_2$ to the atmosphere or be obliged to continue storage operations.

QA/QC protocol outlined above (*Figure 9.5*). This is consistent with the IPCC 2006 Guidelines.

This will likely require a risk assessment to be carried out which is able to define whether the level of risk is below an acceptable minimum level. The risk assessment will need to be informed by reservoir simulations of predicted behaviour of the $CO_2$ over the long-term (1000 years +). Assurance regarding the accuracy of these predictions will only be possible if convergence between the observed and predicted behaviour is achieved, suggesting that the operator has good understanding of the storage site geology (*Figure 9.5*).

There will also be a need to ensure that all wells are plugged using appropriate corrosion resistant cement, and other best practices for site closure are adopted at the time of post-injection.

A legally-binding commitment to the host country to fulfil these requirements will be needed upfront, which could be achieved through host-country approval of the environmental impact assessment component of the CDM documentation (see *Section 9.4.4* and *Section 10.2.1*).

### 9.7.1 *Handling liability post-closure*

Private entities are not able to take on unlimited liability as this is commercially unacceptable i.e. the company would not be able to balance its books to requisite standards. Moreover, as the storage of $CO_2$ is a societal good, then liability must be shared across society. Therefore, at some point following closure, liability will need to be transferred back to the host government.

In the intervening period, operators would remain liable for any *in situ* damage caused by seepage from the storage site, as well as for offsetting any emissions that remerge back to the atmosphere. They would also remain liable for remediation of the site in the event of seepage. Consequently, they would also need to maintain financial responsibility to cover the costs for these potential activities. In this context, a discussion of the potential mechanisms for handling contingent liabilities was set out previously (*Section 8.4*)

## 10 PROJECT APPROVALS

### 10.1 BACKGROUND

CDM projects are subject to a series of approval stages including:

- *Host country approval* by the designated national authority (DNA)
- *Validation* of the PDD by a designated operational entity (DOE)
- *Registration* of the project with the CDM EB
- Buyer country (Annex I) DNA approval, and;
- *Verification* by a DOE of emission monitoring and reporting.

This robust approvals framework should be suitable to ensure only high standard CCS CDM projects can be accepted, although there is likely to be a need to review certain elements in light of the unique characteristics of CCS project activities. In particular, there could be a need to establish a CCS technical group or expert panel to help define and support project approvals procedures.

A more detailed analysis of the approvals process as it might apply to CCS project activities is outlined below.

### 10.2 HOST COUNTRY APPROVAL

A CDM project must receive a Letter of Approval (LoA) from the host country in which the project is located. Approval will be based on a range of different aspects associated with a project including *inter alia*:

i) The contribution the project or activity type makes to the host country sustainable development objectives or priorities;
ii) The contribution the project or activity type makes to the country's technology transfer objectives, which might include promotion or otherwise of certain mitigation project or technology types (e.g. as with China's 65% tax on HFC-23 incineration CDM project activities); and,
iii) The environmental (or potentially social and health) impacts created by the proposed project.

Items *i)* and *ii)* provide non Annex I countries with the sovereign right to reject specific CDM projects or activity types. Alternatively, taxation can be applied as a means of discouraging certain activity types.

Item *iii)* can provide the basis for rejecting projects if unacceptable impacts might be expected, or alternatively, form the basis for project approval against certain commitments to manage potential impacts. This latter element can provide for certain regulatory controls on particular activity types, which is useful for ensuring sound deployment of CCS project activities, as reviewed below.

### 10.2.1 *Environmental Impact Assessment*

A proposed process for defining the potential environmental impacts posed by a CCS under the CDM is outlined above (*Section 9.4*). The scheme outlined requires a range of tasks to be performed by project proponents. As outlined in Step 4 of the scheme (*Figure 9.2*), this process defines the ESHIA. Whilst these steps are included as part of the monitoring scheme design, in fact, many of these components may best reside in the EIA section of the PDD, and the monitoring plan in the PDD should focus on Step 5 – defining the actual techniques to be applied.

Under this proposal, the EIA would need to include the following

- A site performance assessment (covering Steps 1 – 3 of the design of the monitoring plan, plus relevant QA/QC considerations)
- A risk-based assessment of the potential environmental impacts, covering analysis of possible $CO_2$ pathways and receptors (Step 4)

This analysis can be used to define the monitoring plan for the project (*Figure 9.2*). In addition, the ESHIA would also need to include the following elements:

- A commitment to remediate any *in situ* local damages caused by seepage, including method statements for dealing with potential seepage events (e.g. how well-bore blow outs will be rectified) etc.
- A commitment to remediate any global impacts of seepage through purchase of offsets or other mechanisms (e.g. establishment of a credit reserve or use of insurance); and,
- A commitment to continue monitoring post crediting until liability might be transferd (as discussed above; *Section 9.7*).

An approvals scheme of this type should serve to ensure a high level of environmental integrity for a CCS operation in the CDM.

### 10.2.2 *Host country approvals capacity*

Problematically, whilst the scheme outlined would provide a high level of assurance regarding the integrity of a proposed project, it would also pose a significant approvals burden for host country regulators. Moreover, it is likely that many regulators have little or no technical knowledge of CCS operations [(1)], and would therefore be severely compromised in their ability to discharge their duties. Consequently, it is likely that technical support to approve CCS projects would be required, perhaps through appointment of an Expert Group, Roster of Experts or a CCS Technical Group under the CDM EB.

(1) Although countries with active oil & gas operations would be likely have evolved a good level of residual regulatory knowledge on sub-surface engineering and regulation in relevant petroleum ministries.

### 10.2.3 *Stakeholder consultation*

Stakeholder consultation is a mandatory requirement for project validation. Engagement with project stakeholders should be considered as an opportunity for project proponents to undertake community outreach and education in respect of the role of CCS in mitigating climate change.

## 10.3 *VALIDATION*

Assuming acceptance of an appropriate and adequate CDM methodology applicable to CCS, and resolution of other outstanding issues, following completion of a PDD and receipt of host country approval a CCS CDM project will be ready for validation.

Validation is undertaken by a DOE – a DOE accredited to undertake validation for the specific sectoral scope applicable to the project. For CCS projects, designation of a new sectoral scope category will be needed.

Validation is a process involving a thorough check on all the information and data presented in the PDD (e.g. baseline assumptions, additionality, monitoring methodology etc.), as well as ensuring all other permits and approvals are in place (e.g. the LoA, the EIA etc.).

For a CCS project, several new aspects would need to be validated by a DOE relative to other CDM projects. These include:

- Validation of the sub-surface monitoring plan, which will require a good understanding of geology, reservoir simulation techniques, and monitoring technologies; and,
- Review of the project approvals, including the key information contained in the EIA such as the storage site performance assessment, and the risk-based environmental impact assessment.

Because of the new components posed by CCS projects, a new sectoral scope is likely to be needed under the CDM [(1)]. Validating these elements of a PDD would present significant responsibility on the DOE to ensure safe and effective deployment of the project, based on their assessment of complex preparatory evidence provided by the project proponent. Essentially, a certified DOE would need to be able to fully understand and make reasoned judgement as to the efficacy of the QA/QC procedure applied to a CCS project, as outlined above (*Figure 9.3*). As such, there will be a need to ensure appropriate competencies are in place within any certified DOE. These competencies will also extend to verification capabilities, as reviewed below.

## 10.4 *REGISTRATION*

The registration stage of approval would present additional opportunities to review a particular CCS CDM project submission. Following validation but

(1) CDM sectoral scopes can be found here: http://cdm.unfccc.int/DOE/scopelst.pdf. DOE certification can be seen here: http://cdm.unfccc.int/DOE/scopes.html

prior to final registration, a request for review for can be made by either 3 members of the CDM EB, or one of the Parties (host or buyer) involved in the project, within 8 weeks of a request for registration.

There are no CCS specific considerations in the registration stage.

### *10.5 VERIFICATION*

Verification is needed for any CDM project in order for CERs be credited for the emission reductions delivered by project activity. As with validation, verification of the subsurface monitoring component of a CCS CDM project activity will be a specialist activity. Based on the scheme outlined above (*Figure 9.4*), verifiers will need to be able to *inter alia*:

- Understand the monitoring technologies employed in the project;
- Interpret sub-surface data, such as well logs, seismic surveys, gravimetric surveys etc. as well as other data gathered from other sources e.g. airborne remote sensing techniques, soil gas analysis etc.
- Understand the objectives, resolution and limitations of different technologies;
- Interpret the data to recognise evidence of *permanence* of storage (i.e. is the $CO_2$ still in the target formations) and of *seepage* (i.e. do the monitoring data suggest that some of the $CO_2$ has seeped from the reservoir?);
- Interpret reservoir simulation outputs and correlate with monitoring data in order to achieve this;
- Provide expert judgement as to the quantity of $CO_2$ that might have seeped where evidence suggests a seepage event may have occurred;
- Confirm that remediation actions have been carried out by the operator in the event of seepage; and,
- Understand the rationale behind any changes in the monitoring plan originally outlined in the PDD at validation stage e.g. the ability to verify and re-validate any changes to the agreed monitoring plan (as outlined in *Figure 9.4*).

DOEs could only be certified where such competencies are proven (*Box 10.1*).

***Box 10.1 DOE certification***

In order to ensure relevant competencies are in place, the CDM EB could appoint an Expert Group to define the criteria against which a CCS certified DOE could be assessed. The Expert Group would need to define typical expertise and processes that would need to be in place in the relevant DOE to handle the issues laid out for validation and verification.

An organisation such as the *Society of Petroleum Engineers* – whose membership possesses considerable skills in this area – could support the development of such criteria.

Annex A

# CCS Technologies and Applications

## *A1 INTRODUCTION*

This *Annex* begins with a description of major sources of $CO_2$ across a range of power generation technologies (e.g. pulverised coal steam plant, gas turbine, integrated gasification etc) and industrial installations (e.g. gas processing, cement, iron and steel, chemicals production etc), focusing on the main process characteristics, sources of $CO_2$ emissions, and CCS potential.

The principal technologies available for $CO_2$ capture are then described, along with consideration of the implications for changes to plant performance and project emissions. This is followed by a review of $CO_2$ transport and geological storage options. This review provides the basis for the methodology title and applicability criteria highlighted in *Section 2*. It also provides the basis for the discussion of Baselines provided in *Section 4*.

### *A1.1 MAJOR SOURCES OF $CO_2$*

Capture of $CO_2$ is only economically feasible from large point sources of emissions. Power plants, which account for around one third of global $CO_2$ emissions, offer the most likely sources; other source include gas processing, liquefied natural gas (LNG) and synfuel production facilities, oil refineries and other industrial processes such as cement, iron and steel, and chemicals production. A brief synopsis of each is provided below.

#### *A1.1.1 Power generation*

The principal technologies used to generate power from fossil fuels worldwide are, currently pulverised coal-fired steam cycles and natural gas combined cycles. Integrated Gasification Combined Cycles (IGCC) are an emerging option for power generation, although they are not widely deployed due to the complexity of plant operation. $CO_2$ capture could be incorporated in all of these types of plant.

*Pulverised coal-fired generation*

Coal-fired steam cycle is the most common form of power generation technology deployed worldwide. Pulverised coal is burned in a boiler to raise high pressure steam, which is then passed through a steam turbine, generating electricity.

The efficiencies of modern coal fired power plant range from around 25% to around 40% for new build. 'Super-critical' plant with efficiencies of around 47% have been built using higher steam temperatures and higher steam pressures, and ultra-supercritical plant with efficiencies in excess of 50% are under research. The key requirement in the development of higher efficiency steam cycle plant is the development of new materials (e.g. nickel and chromium alloys) that are able to tolerate higher pressures and temperatures. Research is ongoing to develop materials that can tolerate steam conditions up to 375bar/700°C, which would result in efficiencies of up to 55% at favourable sites [(1)]. In many parts of the world, coal-fired power plant are the mainstay of the power generating fleet, and because of the start-up times involved they generally operate as base load plant with availability [(2)] usually in excess of 85%.

An alternative to pulverised coal combustion is fluidised bed combustion; the efficiencies, emissions and costs of fluidised bed combustion power plants are broadly similar to those of pulverised coal plants and the way in which $CO_2$ capture would be introduced is very similar.

*Gas boilers and turbines*

In a natural gas combined cycle plant electricity is generated by the combustion of natural gas in a gas turbine; the hot exhaust gases are used to further raise steam in a boiler which drives a steam turbine, creating additional electricity (hence the term 'combined' cycle).

Natural gas combined cycle plants have been largely introduced during the last 15 years, as the market for natural gas for power generation has become deregulated. Worldwide, gas turbine based systems are taking well over half of the market for new power plant. Large, commercial gas turbine combined cycle plants can often achieve thermal efficiencies of up to 55-60% and higher efficiencies are expected to be achieved in future.

As gas-fired power plant can be fired up relatively quickly, they can be turned on and off to meet peak electricity demand ('peak-shaving') as well as providing base-load power generation.

*Integrated gasification technology*

In an integrated gasification combined cycle (IGCC) plant, fuel is reacted with oxygen and steam in a gasifier to produce a fuel gas consisting mainly of carbon monoxide, $CO_2$ and hydrogen ('syngas'). This is then cleaned and burned to generate power in a gas turbine combined cycle plant. The IGCC concept enables coal and heavy oils to be combusted at similar efficiencies as achieved in conventional pulverised coal plant (at around 45-50%). Although the efficiency of IGCC technology will increase in future in line with those of gas turbine combined cycles, the efficiency of IGCC plants will always be constrained by the energy losses associated with gasification and gas cleaning.

Over 300 gasifiers are reported to be in operation, mostly producing syngas as an intermediate stage in chemicals production. Commercial-scale coal IGCC demonstration plants have been built in the USA, Netherlands and Spain. There is also an interest in the oil industry in gasification of refinery residues to produce electricity and/or hydrogen, and three large plants are currently being built in Italy. IGCC has been successfully demonstrated but capital costs require further reduction, and the reliability and operating flexibility

(1) IEA GHG R&D Programme, 2001
(2) The rate at which plant operates at full load capacity

needs to be improved to make it widely competitive in the electricity market [3].

*Biomass power generation*

Biomass refers to organic matter other than fossil fuels (i.e. oil, gas, coal) used for energy generation, and includes solid biomass (energy crops, crop residues and animal waste), biogas (methane-rich gas produced by anaerobic digestion of organic waste), and liquid bio-fuels (usually used as alternative fuel in transport).

Solid biomass may be combusted in boilers to produce electricity or heat (or both in the case of combined heat and power; CHP) and can also be co-fired with coal in conventional thermal power stations. Because biomass sequesters $CO_2$ as it grows (which is released upon combustion), it is considered as a zero-carbon generation fuel or 'carbon neutral'. However, life-cycle $CO_2$ emissions associated with cultivation, processing and transportation may be significant depending upon project characteristics [4].

A biomass generation plant operating at base load may provide a potential source of $CO_2$ emissions suitable for capture; similarly biomass could be used to co-fire in pulverised coal power plant with $CO_2$ capture. In these cases, net negative emissions may arise from the overall CCS system.

### A1.1.2 Natural gas processing

Depending on its source, raw natural gas extracted from reservoirs often contains varying concentrations of $CO_2$, which, along with hydrogen sulphide ($H_2S$), must be reduced for technical and safety reasons where present (gas 'sweetening'). Pipeline specifications often require that the $CO_2$ concentration be lowered to around 2% by volume (although this amount varies in different places) to prevent pipeline corrosion, to avoid excess energy use in transport and to increase the heating value of the gas [5]. As such, $CO_2$ removal (or "capture") is sometimes an integral part of natural gas field development engineering, regardless of whether the $CO_2$ is stored or not i.e. the $CO_2$ is usually stripped and vented. Appropriate incentives such as the CDM could provide the trigger to mitigate the not insignificant volumes of $CO_2$ emissions form this source which are currently vented worldwide every year.

The IPPC (2005) estimates that about half of raw natural gas production worldwide could contain $CO_2$ at concentrations averaging 4% by volume. Using this assumption, if half of the worldwide production of 2,618.5 billion $m^3$ of natural gas in 2003 is reduced in $CO_2$ content from 4% to 2% mol, the resulting amount of $CO_2$ removed - and therefore the total CCS potential - would be at least 50 $MtCO_2$ per year [6]. Based on recent work undertaken, the

(3) IEA GHG R&D Programme, 2001

(4) Appropriate emissions factors for each biomass type should be deployed as outlined in the AFOLU section of the IPPC 2006 Reporting Guidelines for National Greenhouse Gas Inventories

(5) IPPC Special Report on Carbon Dioxide Capture and Storage, 2005

(6) IPCC Special Report on Carbon Dioxide Capture and Storage, 2005

authors of this report are aware of at least 10 offshore gas platforms worldwide with $CO_2$ storage potential of between 3-8 Mt$CO_2$ per year (presently cold vented).

There are currently two operational natural gas plants storing $CO_2$: BP's In Salah plant in Algeria and Statoil's plant at the Sleipner field in the North Sea, both of which store around 1 Mt$CO_2$ per year.

### *A1.1.3 Liquefied natural gas production*

Liquefied natural gas (LNG) is natural gas that has been processed to remove impurities and heavy hydrocarbons and then condensed into a liquid i.e. 'liquefied' at almost atmospheric pressure by cooling it to approximately -163 degrees Celsius. LNG is around 1/600th of the volume of natural gas at standard temperature and pressure making it much more cost-efficient to transport over long distances where pipelines do not exist.

LNG facilities require a large amount of energy for the liquefaction process, with upwards of 150 MW of installed capacity per LNG train (typical LNG trains are broadly in the range 3-7 millions tonnes per annum; mtpa). Usually power is supplied from a series of separate aero-derivative or open-cycle gas turbines (OCGT). These plants offer greater flexibility ahead of combined-cycle units (CCGT). As a result, LNG operations tend to have a low thermal efficiency in power generation relative to CCGT technologies. Some LNG projects in the future may look to utilize a single CCGT plant and use mechanical drives for compression and refrigeration purposes. This would create an optimised system for the deployment of CCS as it would result in a single large point source of $CO_2$ as opposed to numerous smaller units which would require a $CO_2$ gathering system on site [(7)].

The gas purity specifications for LNG are higher than those required for transport via pipeline. Prior to gas liquefaction, processing must remove impurities from the natural gas (such as oxygen, $CO_2$, sulphur compounds etc.) to avoid solid components being formed during liquefaction (such as dry-ice); the process can be designed to purify the LNG to almost 100% gas (methane, ethane etc.). Because of the high purity levels required (typically 99.9% gas) $CO_2$ removal (or 'knockout') is nearly always required, representing a potentially large point source of emissions suitable for capture. As with natural gas processing (*Section A1.1.2*), the $CO_2$ capture process is thus an integral part of many LNG facilities, with the removed $CO_2$ being vented direct to the atmosphere.

Two planned LNG projects, the Snohvit gas field Norway and the Gorgon field in Australia propose to re-inject the stripped reservoir $CO_2$ into geological formations. The latter will be the largest CCS project in the world to date, with more than 4 Mt$CO_2$ per year re-injected based on two 5 mtpa LNG trains. Both projects re-inject the 'knockout' $CO_2$ only. However, in

(7) The Snohvit installation utilises a central combined cycle gas turbine plant; however, capture is not deployed from this source due to adverse economics.

principle, those emissions associated with the power generation required for refrigeration and compression could also be captured, particularly if system design is optimised, as described above.

### *A1.1.4 Refineries*

Refineries process crude oils, natural gas liquids and synthetic crude oils to produce final refined products (primarily fuels and lubricants). For this transformation to occur, part of the energy content of the products obtained from crude oil is used in the refinery. Refineries manufacture products for fuel and non-energy uses, and in doing so produce hydrogen and other gases, intermediate products and basic chemicals.

Refineries produce large amounts of $CO_2$ emissions, of which about two thirds of the $CO_2$ emissions are from combustion of oil in fired heaters. The flue gas from these heaters is similar to the flue gas in power stations, so $CO_2$ could be captured using the same techniques and at broadly similar costs [(8)]. Where refineries are integrated with other facilities (for example, upgraders or cogeneration plants) significant potential could exist for process optimisation to create more concentrated point sources suitable for $CO_2$ capture.

### *A1.1.5 Synthetic fuel production*

Synfuel plants produce synthetic petroleum products from coal, condensates or natural gas. Coal-to-liquids (CTL) and Gas-to-liquids (GTL) technologies are not yet widely deployed, although these processes are expected to become increasingly used over coming decades, especially if high oil prices (US$70+ barrel) are sustained over the medium term.

The first stage of synfuel production in CTL and GTL technology involves the forming of a syngas from the hydrocarbon input fuel to yield a mixture of hydrogen and $CO_2$. There are four main processes for producing the syngas:

i) Steam reforming
ii) Partial oxidation (POX)
iii) Autothermal reforming
iv) Combined or two-step reforming

The choice of syngas former is usually dependent on scale, ease of operation, cost of fuel etc. and will have an impact on the overall thermal efficiency of the process, as well as the quality of input syngas into the next step. Optimisation with the second step is also a major challenge.

The second step involves the reaction of the produced syngas with a catalyst in a process known as the Fischer Tropsch synthesis, from which a range hydrocarbon products are produced (including gasoline, diesel, solvents, waxes and tars).

(8) IEA GHG R&D Programme, 2001

There are two main categories of natural gas-based Fischer-Tropsch process technology: the high and the low temperature versions [9].

- The *high-temperature*, iron catalyst-based Fischer-Tropsch GTL process produces fuels such as petrol (gasoline) and gasoil that are closer to those produced from conventional crude oil refining. The resultant GTL products are virtually free of sulphur, but contain aromatics.
- The *low-temperature*, cobalt catalyst-based Fischer-Tropsch GTL process, however, produces an extremely clean synthetic fraction of gasoil called GTL Fuel that is virtually free of sulphur and aromatics.

The CTL process produces significant quantities of $CO_2$. Emissions arise from coal combustion to produce process electricity and from also from producing hydrogen feedstock from coal. GTL is produces lower emissions, but also requires significant energy inputs in the Fischer-Tropsch processing.

Capture technology has yet not been applied to CTL or GTL facilities, although these plants represent large point sources suitable for capture, and can be expected to be candidate CCS facilities in the future. Presently there is no optimum process for synfuel production, and the area is under continuous research to improve overall process efficiency and reduce costs.

Several companies are developing and significantly enhancing the original Fischer Tropsch technology, including *Shell*, *Chevron, Sasol* and others, with large plants either planned or in operation in South Africa, North Africa, the Middle East, South East Asia and East Asia.

### *A1.1.6 Cement production*

$CO_2$ emitted in the flue gases from cement production also represents a potential source of emissions for capture; emissions from this sector account for 6% of the total emissions of $CO_2$ from stationary sources worldwide.

In cement manufacture, $CO_2$ is produced during the production of clinker, an intermediate product that is ground to produce cement. During the production of clinker, limestone is heated and 'calcinated' to producing lime, with $CO_2$ as a by-product. The lime then reacts with silica, alumina, and iron oxide in the raw materials to make the clinker. Cement production requires large quantities of fuel to drive the high temperature, energy-intensive reactions associated with the calcination of the limestone. $CO_2$ emissions are directly related to clinker production rates and the fuel combusted. Process $CO_2$ emissions are determined from the weights and compositions of all carbonate inputs from all raw material and fuel sources, the emission factors for the carbonates, and the percentage of calcination achieved [10].

At present, $CO_2$ capture has not been applied at cement plants, although the potential is significant. The concentration of $CO_2$ in the flue gases is between

(9) Royal Dutch Shell website 2006

(10) IPCC Draft Guidelines for National Greenhouse Gas Inventories 2006

15-30% by volume, which is higher than in flue gases from power and heat production (typically 3-15% by volume). However, the high oxygen content (circa 10%) and high level of contaminants make capture from cement plants challenging. In principle, though, post-combustion $CO_2$ capture could be applied to cement production plants, with additional generation of steam required to regenerate the solvent used to capture emissions (11). Oxy-fuel combustion capture systems may also prove feasible (12).

Another emerging option would be the use of calcium sorbents for $CO_2$ capture, as calcium carbonate (limestone) is a raw material already used in cement plants. All of these capture techniques could be applied to retrofit or new plant applications (13).

### A1.1.7 *Iron and steel production*

The iron and steel industry is the largest energy-consuming manufacturing sector in the world, accounting for 10-15% of total industrial energy consumption (14).

There are two main types of iron- and steel-making technologies are in operation today:

- *The integrated steel plant* has a typical capacity of 3-5 million tonnes per year of steel and uses coal as its basic fuel with, in many cases, additional natural gas and oil.
- *The mini-mill* uses electric arc furnaces to melt scrap with a typical output of 1 million tonnes per year of steel and an electrical consumption of 300-350 kWh per tonne of steel.

$CO_2$ emissions per unit of steel production vary widely depending on the method of steel production. Increasingly mini-mills blend direct-reduced iron (DRI) with scrap to increase steel quality. The production of direct-reduced iron involves reaction of high oxygen content iron ore with hydrogen and carbon monoxide to form reduced iron plus water and $CO_2$. As a result, many of the direct reduction iron processes could capture a pure $CO_2$ stream (15).

Two primary opportunities exist at present for the capture of $CO_2$ emissions from the iron and steel industry:

- *$CO_2$ recovery from blast furnace gas and recycle of CO-rich top gas to the furnace.* A minimum quantity of coke is still required and the blast furnace is fed with a mixture of pure $CO_2$ and recycled top gas. The furnace is, in effect, converted from air firing to oxy-fuel firing with $CO_2$ capture. This would

(11) IPPC Special report on Carbon Dioxide Capture and Storage, 2005
(12) The reduction of greenhouse gas emissions from the cement industry. Report PH3/7, May 1999, IEA Greenhouse Gas R&D Programme
(13) IPPC Special Report on Carbon Dioxide Capture and Storage 2005
(14) IEA GHG R&D Programme, Greenhouse gas emissions from major industrial sources III - Iron and Steel Production Report PH3/30, 2000
(15)IPPC Special report on Carbon Dioxide Capture and Storage, 2005

recover 70% of the $CO_2$ currently emitted from an integrated steel plant [16]. It would be feasible to retrofit existing blast furnaces with this process.

- *Direct reduction of iron ore, using hydrogen derived from a fossil fuel in a pre-combustion capture step*. Instead of the fuel being burnt in the furnace and releasing its $CO_2$ to atmosphere, the fuel would be converted to hydrogen and the $CO_2$ would be captured during that process. The hydrogen would then be used as a reduction agent for the iron ore. Capture rates should be 90-95% according to the design of the pre-combustion capture technique [17].

### *A1.1.8 Chemical manufacture*

*Ammonia manufacture*

$CO_2$ is a by-product of ammonia production, which is produced from nitrogen and hydrogen. Around 85% of worldwide ammonia production is produced using steam reforming of a hydrocarbon feedstock to produce hydrogen (with nitrogen provided from air intake). The most common hydrocarbon used is natural gas, although hydrogen can also be obtained from other hydrocarbons (i.e. coal and oil), and water [18].

The production of ammonia represents a significant industrial source of $CO_2$ emissions. The primary release of $CO_2$ at plants using the natural gas steam reforming process occurs during regeneration of the $CO_2$ scrubbing solution with lesser emissions resulting from condensate stripping. In a typical modern plant, the amine solvent process will be used to treat 200,000 $Nm^3$ per hour of gas from the steam reformer, producing 72 tonnes per hour of concentrated $CO_2$ [19].

The rate of $CO_2$ produced in modern ammonia plants using natural gas reforming is about 1.27 $tCO_2$ per tonne ammonia. Therefore, with a world ammonia production of about 100 million tonnes per year, about 127 $MtCO_2$ per year is currently produced [20]. Not all of this total would be available for storage however, as ammonia plants are frequently combined with urea plants, which are capable of utilizing 70-90% of the $CO_2$. Around 0.7 $MtCO_2$ per year captured from ammonia plants is currently used for $CO_2$-EOR in the US [21].

(16) Dongke, M.A., L. Kong, and W.K. Lu, 1988: Heat and mass balance of oxygen enriched and nitrogen free blast furnace operations with coal injection. I.C.S.T.I. Iron Making Conference Proceedings.
(17) Duarte, P.E. and E. Reich, 1998: A reliable and economic route for coal based D.R.I. production. I.C.S.T.I Iron-making Conference Proceedings 1998.
(18) Hocking, M. B. (1998), Handbook of Chemical Technology and Pollution Control, Academic Press USA.
(19) Apple, M. 1997: Ammonia. Methanol. Hydrogen. Carbon Monoxide. Modern Production Technologies. A Review. Published by Nitrogen - The Journal of the World Nitrogen and Methanol Industries. CRU Publishing Ltd.
(20) IPPC Special report on Carbon Dioxide Capture and Storage, 2005
(21) Beecy, D.J. and Kuuskraa, V.A., 2005: Basic Strategies for Linking $CO_2$ enhanced oil recovery and storage of $CO_2$ emissions. In E.S.Rubin, D.W. Keith and C.F. Gilboy (eds.), Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5-9, 2004, Vancouver, Canada. Volume I: Peer Reviewed Papers and Overviews, Elsevier Science, Oxford, UK, 351-360.

*Ethanol manufacture*

Ethanol is made from biomass materials containing sugars, starches, or cellulose. Ethanol production essentially involves a four stage process:

1. Grain receiving, storing and milling
2. Conversion and liquefaction, fermentation and evaporation
3. Distillation and sieving
4. Liquid-solid separation

$CO_2$ is emitted in large quantities during the fermentation stage of production. At present many ethanol plants collect the $CO_2$ and market it as co-product. The $CO_2$ is usually cleaned of any residual alcohol, compressed, and sold to other industries.

A project has been developed in Kansas (US) to utilise $CO_2$ from an ethanol plant for $CO_2$-EOR. Waste heat from a 15 MW gas-fired turbine municipal generator provides heat inputs for a 25 million gallon per year ethanol plant, with $CO_2$ captured for use in a $CO_2$ miscible flood demonstration project. The project is the first to use $CO_2$ emissions from ethanol production in $CO_2$-EOR operations; the full $CO_2$ stream from the plant could supply a small commercial project capable of producing five million barrels of oil and storing 1.5 million tonnes of $CO_2$ over twenty years [(22)].

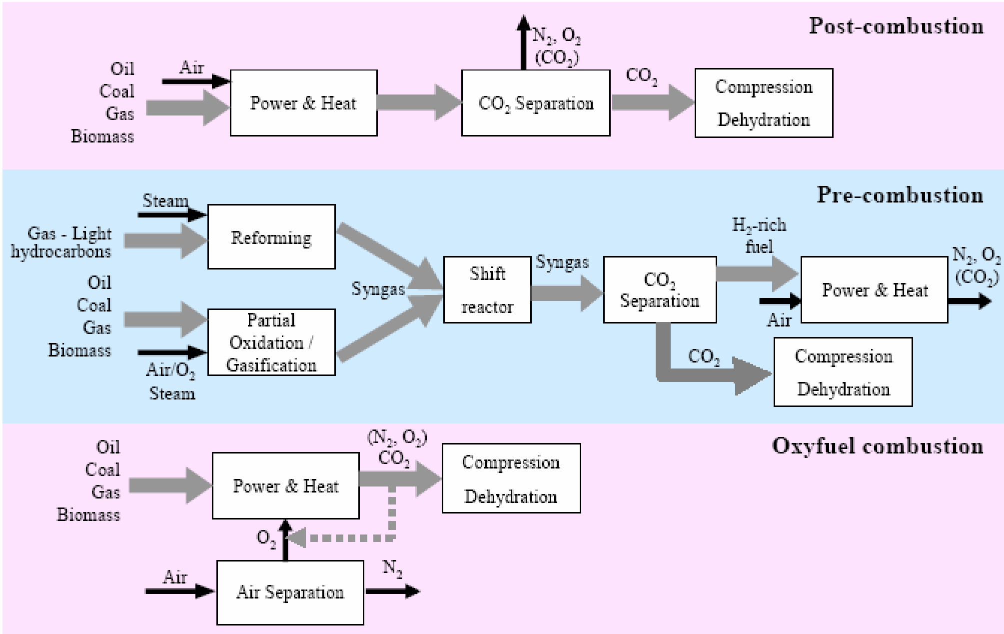
## *A1.2* *CAPTURE TECHNOLOGIES*

Three principal technologies are widely considered as being the most promising for capturing $CO_2$ from large point sources in the near term. Several of these have already ben referred to in the previous *Sections*, and include:

- Post-combustion capture
- Pre-combustion capture; and
- Oxyfuel combustion

(22) American Association of Petroleum Geologists Annual Meeting, March 2002

*Figure A1.1* *$CO_2$ capture systems*




Source: IPPC SRCCS, 2005

### A1.2.1 *Post-combustion capture*

Post-combustion capture involves the passing of the dilute $CO_2$ offgas or exhaust stream through a stripping plant, where $CO_2$ is preferentially adsorbed into a suitable solvent such as amine. The $CO_2$-rich amine is subsequently passed through a stripper, where it is steam heated to release the $CO_2$ from solution. The technology requires significant scale-up to apply to power plants. The largest plant currently operating is at the Trona Soda ash plant (California) which captures around 800 $tCO_2$ per day. Indicative estimates for a 500 MW conventional (pulverised) coal plant suggest that a system able to handle around 10,000 $tCO_2$ per day would be required.

### A1.2.2 *Pre-combustion capture*

In pre-combustion capture the $CO_2$ stream is separated from the fuel carrier before being passed through the stripper by application of gasification to produce a syngas from which the $CO_2$ can be removed. Pre-combustion $CO_2$ capture has significant advantages over post combustion capture, principally because of the higher $CO_2$ concentration and higher partial pressure of the gas train sent to the $CO_2$ removal plant. This means that $CO_2$ capture is possible using lower volumes of solvents, whilst adsorbents which can be expanded at low pressures can be used, avoiding the need to heat the rich solvents line.

### A1.2.3 *Oxyfuel combustion*

Oxyfuel combustion uses either almost pure oxygen or a mixture of almost pure oxygen and $CO_2$-rich recycled flue gas instead of air for fuel combustion. The flue gas contains mainly water and $CO_2$ with excess oxygen required to ensure complete combustion of the fuel. It will also contain any other components in the fuel, any diluents in the oxygen stream supplied, any inert matter in the fuel and from impurities due to combustor air leakage. The net flue gas, after cooling to condense water vapour, contains from about 80 to 98 percent $CO_2$ depending on the fuel used and the particular oxy-fuel combustion process. A high $CO_2$ content flue gas could require minimum treatment prior to injection in the sub-surface.

Although elements of oxyfuel combustion techniques are in use in the iron and steel and glass melting industries today, oxy-fuel technologies for $CO_2$ capture have yet to be deployed on a commercial scale. The largest air separation unit built to date can produce about 5,000 $tCO_2$ per day, suitable for a 300MWe coal-fired plant (23).

### A1.2.4 *Natural gas sweetening*

Depending upon the level of $CO_2$ in raw natural gas, different processes for natural gas processing are available:

- Chemical solvents
- Physical solvents
- Membranes

Natural gas processing using chemical (alkanolamine) solvents is the most commonly used method. The $CO_2$ recovery process from natural gas is similar to that for flue gas treatment by chemical absorption, except that in natural gas processing, absorption occurs at high pressure with subsequent expansion before the stripper column, where $CO_2$ is flashed and separated. When the $CO_2$ concentration in the raw natural gas is high, membrane systems may be more economic (24).

### A1.2.5 *Capture technology development*

Several other technologies for capturing $CO_2$ are under research, including chemical looping, pressure swing absorption and use of membranes (25). However, the principal process likely to be employed in the near-term is amine stripping (pre- or post-combustion), which has been widely deployed for removing $CO_2$ from gas streams for over 50 years, albeit not at the scale required for large power plants. To date, only post combustion flue gas scrubbing has been widely applied at relatively large scales in industry. Pre-combustion technologies have been applied in other applications, principally the production of hydrogen for oil refining and ammonia manufacture and in experimental integrated gasifier systems. Oxyfuel firing technologies are still at an early stage of research and development.

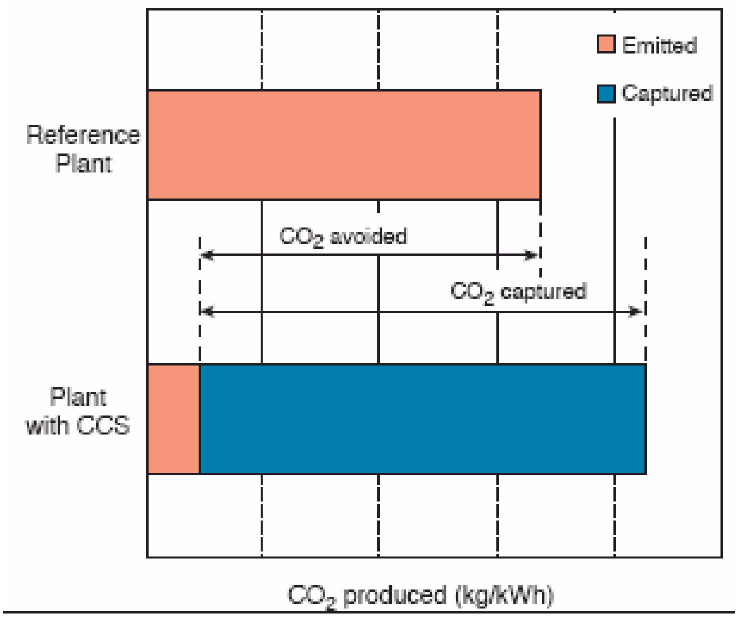
### A1.2.6 *Net reduction of $CO_2$ emissions and performance efficiency*

The atmospheric $CO_2$ emissions avoided with a CCS project is determined by the share of $CO_2$ captured and the efficiency loss in power generation plants

(23) VGB. $CO_2$ Capture and Storage. A VGB Report on the State of the Art. VGB Power Tech e.V., Essen, Germany, 2004.
(24) IPPC Special Report on Carbon Dioxide Capture and Storage, 2005
(25) Membranes are widely used now for stripping $CO_2$ from natural gas.

or industrial processes due to the additional energy required for capture (the 'energy penalty') (26). The emissions avoided (i.e. the net reduction) is shown in *Figure A1.2*.

***Figure A1.2*** ***$CO_2$ capture and storage from power plants***




The loss in conversion efficiency in the capture plant and the additional energy required for transportation and storage result in a larger amount of "CO2 produced per unit of product"(lower bar) relative to the reference plant (upper bar) without capture.

Source: IPPC SRCCS, 2005

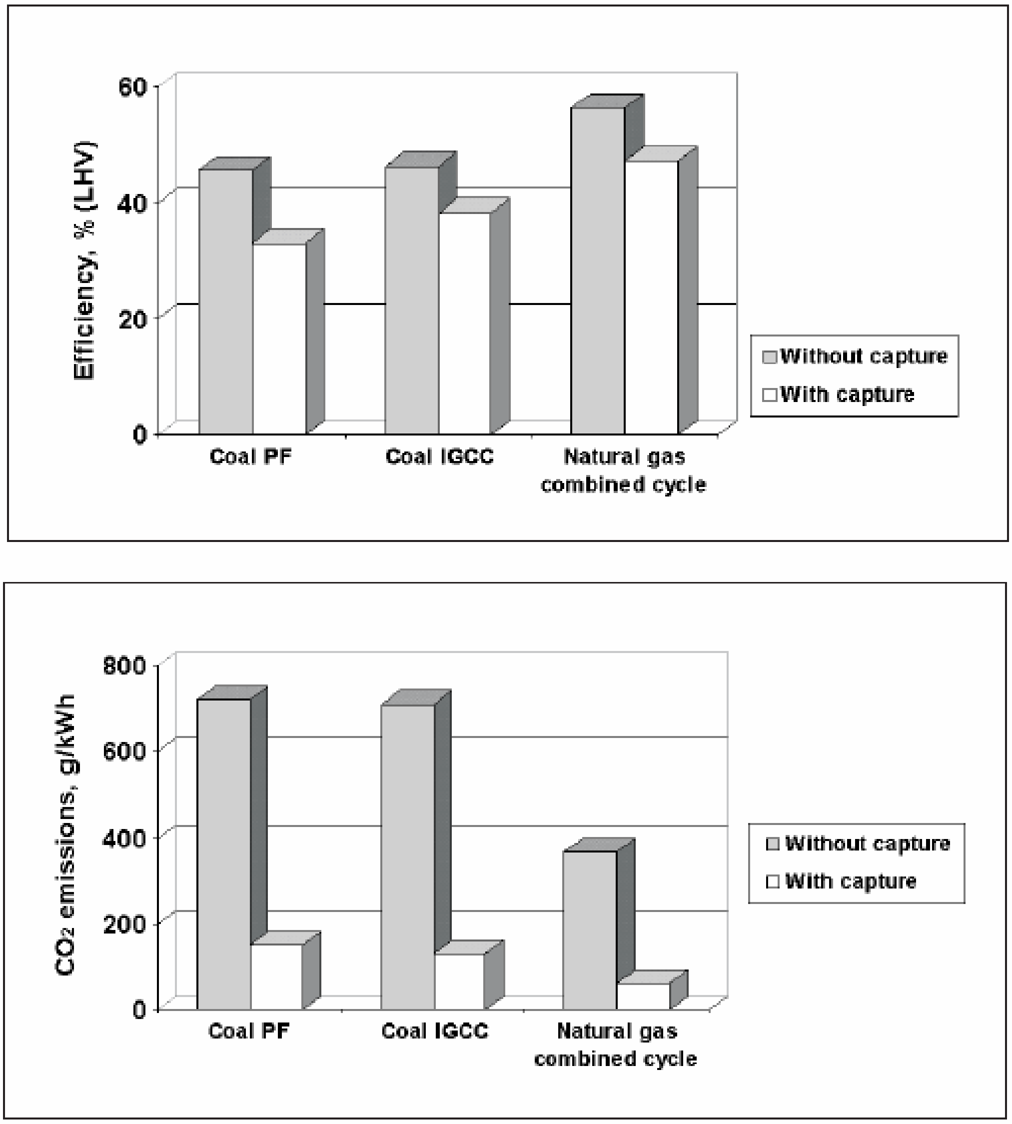
Using currently available technology, around 85 - 95 % of total process $CO_2$ emissions can be captured. A CCS project needs between 8% and 40% more energy than the equivalent project without CCS, most of which is used for capture and compression (27) . *Figure A1.3* shows the results of an *IEA Greenhouse Gas R&D Programme* study that reviewed the performance of new 500 MW gas and coal fired power plants with and without $CO_2$ capture. Comparative $CO_2$ emissions and efficiencies are shown (28).

(26) Other factors include transport and storage, and the fraction of $CO_2$ permanently retained in storage.

(27) Although there is little extra energy penalty imposed on natural gas processing and LNG production as the stripping of $CO_2$ must be undertaken irrespective of whether the $CO_2$ will be stored or vented to the atmosphere.

(28) Power stations with post-combustion capture using amine scrubbing, and pre-combustion capture using Selexol® physical solvent scrubbing were assessed. The coal IGCC uses pre-combustion capture and the pulverised coal and natural gas combined cycle plants use post-combustion capture (the efficiency and emissions would be very similar for a natural gas combined cycle with pre-combustion capture). Compression of the $CO_2$ to a pressure of 110 bar for transportation to storage is included.

*Figure A1.3 Power generation efficiency and $CO_2$ emissions*




Source: IEA GHG R&D Programme, 2001

$CO_2$ capture is found to reduce the overall emissions of $CO_2$ per unit of electricity by around 80%, but with generating efficiency decreases of around 8-13%. The reduction in efficiency is less in the gas fired plant than in the pulverised coal plant, mainly because less $CO_2$ has to be captured and compressed per unit of electricity produced. The 'energy penalty' for $CO_2$ capture is lower in the IGCC plant than in the pulverised coal plant, because less energy is needed for regeneration of the $CO_2$ capture solvent.

## A1.3 TRANSPORTATION

$CO_2$ is in a gaseous form at atmospheric pressure and occupies a large volume, which requires large-scale facilities for transportation. There are two principal methods proposed for transportation of $CO_2$:

- High pressure pipelines; and
- Marine transport using liquefaction

Liquefied gas can also be carried by rail tank-cars and by road tankers, but it is unlikely these will be attractive options for large-scale CCS projects.

### *A1.3.1 High pressure pipelines*

$CO_2$ transportation in high-pressure pipelines is a widely employed technique for transporting $CO_2$ for the purpose of $CO_2$-EOR. Principally, experience has come from the network of $CO_2$ pipelines in operation around the Permian Basin in West Texas. Here $CO_2$ is transported from anthropogenic and naturally occurring $CO_2$ sources (e.g. the McElmo Dome), to mature oil fields around West Texas. In total the Permian Basin has over 2,500 km of high pressure $CO_2$ pipelines, with a total capacity for transporting around 50 M $tCO_2$ per year.

$CO_2$ pipeline operators and regulators have established minimum specifications for composition [(29)]. Once the $CO_2$ has been dried and meets the transportation criteria, the $CO_2$ is measured and transported to the final use site. All the pipelines have fiscal standard metering systems that accurately account for sales and deliveries into and out of each line, and SCADA (Supervisory Control and Acquisition of Data) systems for measuring pressure drops, and redundancies built in to allow for emergencies.

### *A1.3.2 Marine transport using liquefaction*

Marine transport offers a more flexible alternative to $CO_2$ transportation than high-pressure pipelines. Liquefaction is an established technology for gas transport by ship as LPG (liquefied petroleum gas) and LNG (liquefied natural gas), albeit with different conditions e.g. natural gas liquefaction is temperature driven, whilst $CO_2$ liquefaction is pressure driven.

Because $CO_2$ is continuously captured at the plant whilst the cycle of ship transport is periodic, a marine transportation system must include temporary storage on land and a loading facility. The capacity, service speed, number of ships and shipping schedule will be planned considering the capture rate of $CO_2$, transport distance, social and technical restrictions, etc. The delivery process depends on the $CO_2$ storage system: if the delivery point is onshore, the $CO_2$ is unloaded from the ships into temporary storage tanks; if the delivery point is offshore, then ships might unload to a platform, to a floating storage facility to a single-buoy mooring, or directly to a storage system.

Due to limited demand, only small scale $CO_2$ marine transport has taken place to date. Worldwide, there are only four small ships used for this purpose which transport liquefied food grade $CO_2$ from large point sources such as ammonia plants in Northern Europe to coastal distribution terminals in the consuming regions. From these distribution terminals $CO_2$ is transported to the customers either by tanker trucks or in pressurised cylinders. Design work

(29) See: US DOT, 49 CFR 195 Transportation of Hazardous Liquids by Pipeline.

is ongoing in Norway and Japan for larger $CO_2$ ships and their associated liquefaction and intermediate storage facilities [(30)].

### A1.4 STORAGE

Geological storage of $CO_2$ may take place onshore or offshore, in:

- *Depleted or partially depleted oil and gas fields:* Either as part of, or without, enhanced oil recovery ($CO_2$-EOR) or enhanced gas recovery (EGR) operations.
- *Deep saline reservoirs:* These are porous and permeable formations containing saline water in their pore spaces.
- *Coal seams:* Either with or without enhanced coal-bed methane recovery (ECBM) operations.

Additionally, niche opportunities for storage may arise from other concepts such as storage in salt caverns, basalt formations and organic-rich shales.

The three main storage options are described further below.

#### A1.4.1 *Depleted or partially depleted oil and gas fields*

Oil and gas reservoirs are porous formations capped with impermeable cap rock. Worldwide, there are thousands of depleted or partially depleted oil and gas reservoirs which represent potential sites for $CO_2$ storage. Because the geology of these sites are well understood and their ability to hold gases and liquids for millions of years proven, they represent particularly attractive storage media. In addition, there may be the potential to re-use some parts of the hydrocarbon production equipment to transport and inject the $CO_2$.

Injection of $CO_2$ can also be used for $CO_2$-EOR, as $CO_2$ can increase reservoir pressure, increase the mobility of certain oils through miscible flooding [(31)]. $CO_2$ injected into suitable, depleted oil reservoirs can enhance oil recovery by typically 10-15% of the original oil in place in the reservoir; the additional oil production could, in certain circumstances, more than offset the cost of $CO_2$ capture and injection. The injection of $CO_2$ for $CO_2$-EOR purposes is discussed further in *Section A1.4.4*.

A number of depleted gas fields worldwide could be adapted easily for storage of $CO_2$ [(32)]. Temporary underground storage of natural gas has been undertaken in the natural gas industry for many decades; natural gas is routinely injected into, stored and withdrawn from hundreds of underground storage fields.

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(30) IPCC Special Report on Carbon Capture and Storage 2005

(31) The most typical process involves the alternative injection of $CO_2$ and water, with the water used to act as piston to push through the miscible mix of $CO_2$ and water to the extraction well, know as water alternating gas (WAG). Typically is only applicable to certain types light crud (> 25º API).

(32) IEA GHG R&D Programme, 2001

### A1.4.2 *Deep saline formations*

There are many deep saline formations worldwide that could potentially be used for storage of $CO_2$. Injection of $CO_2$ into deep saline reservoirs would use techniques similar to those for disused oil and gas fields. The major challenge for utilising saline formations is the lack of data on site characteristics, relative to oil & gas fields.

Around one million tonnes per year of $CO_2$ is currently being injected into a deep saline formation in *Statoil's* Sleipner gas field in the North Sea in conjunction with gas production. $CO_2$ removed from a natural gas stream, which would otherwise be vented, is stored underground in the Utsira formation, a sand formation extending under a large area of the North Sea at a depth of about 800m. The flows of $CO_2$ injected at the Sleipner field are being monitored and modelled as part of an international project established by *Statoil* with the *IEA Greenhouse Gas R&D Programme*.

### A1.4.3 *Coal seams*

Unminable coal seams represent another potential storage medium. $CO_2$ can be injected into suitable coal seams where it will be adsorbed onto the coal, locking it up permanently. Injection of $CO_2$ can displace methane trapped in the coal beds. Although methane is already extracted from coal seams by depressurisation, this typically recovers only around 50% of the coal bed methane; injection of $CO_2$ enables greater methane recovery rates, at the same time at storing $CO_2$. because coal can adsorb about twice as much $CO_2$ by volume as methane, even if the recovered methane is burned and the resulting $CO_2$ is re-injected, the coal bed can still provide net storage of $CO_2$ (33).

Although a large amount of coal bed methane is already produced worldwide, there is limited experience with $CO_2$ enhanced coal bed methane (ECBM) worldwide, including the RECOPOL project in Poland, and the San Juan project in the Allison Unit in New Mexico, USA. Over 100 000 tonnes of $CO_2$ has been injected at this unit over a three year period. The Alberta *Research Council* is also undertaking an ECBM project using $CO_2$ and nitrogen mixtures under an international research project facilitated by the *IEA Greenhouse Gas R&D Programme* in order to evaluate possible process improvements.

### A1.4.4 *Enhanced Hydrocarbon Recovery*

Enhanced oil recovery (EOR) is the recovery of oil from a reservoir by means other than using the natural reservoir pressure. EOR generally results in increased amounts of oil being removed from a reservoir in comparison to methods using natural pressure or pumping alone, as used in conventional oil extraction. The three major types of enhanced oil recovery operations are:

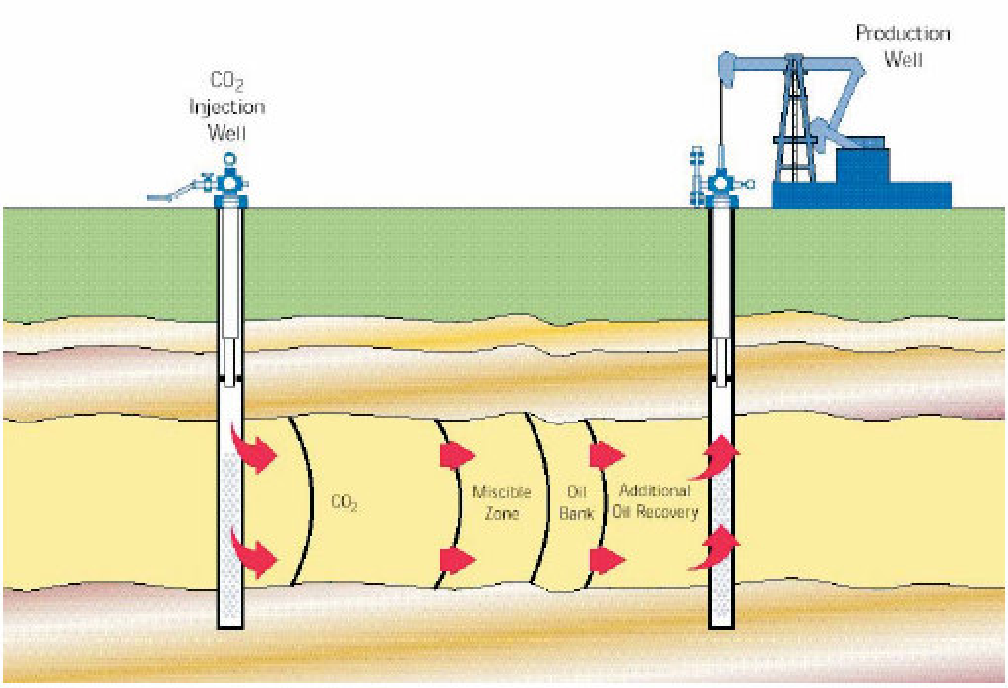
- chemical flooding (alkaline flooding or micellar-polymer flooding);
- miscible displacement ($CO_2$ injection or hydrocarbon injection); and

(33) IEA GHG R&D Programme 2001

- thermal recovery (steam-flood or in-situ combustion)

In $CO_2$-EOR operations (see *Figure A1.4*), $CO_2$ is injected into the oil reservoir and a proportion of the amount injected is then usually produced along with oil, hydrocarbon gas and water at the production wells. The $CO_2$-hydrocarbon gas mixture is separated from the crude oil and may be re-injected into the oil reservoir, used as fuel gas on site or sent to a gas processing plant for separation into $CO_2$ and hydrocarbon gas, depending upon its hydrocarbon content. Enhanced gas recovery (EGR) and enhanced coal bed methane (ECBM) processes generally attempt to avoid $CO_2$ production because it is costly to separate the $CO_2$ from a produced gas mixture [(34)].

***Figure A1.4*** ***$CO_2$ enhanced oil recovery***




Source: IEA GHG R&D Programme, 2001

Depending on the economics of recycling versus injecting imported $CO_2$, the $CO_2$ separated from the hydrocarbon gas may be recycled and re-injected in the $CO_2$-EOR operation, or vented. $CO_2$-rich gas is also released from the crude oil storage tanks at the EOR operation. This vapour may be vented, flared or used as fuel gas.

In 2001, about 33 million $tCO_2$ per year was used at more than 74 $CO_2$-EOR projects in the USA [(35)]. Most $CO_2$ used in $CO_2$-EOR operations is extracted from natural reservoirs but some is captured from natural gas plants and ammonia production.

The most widely published major $CO_2$-EOR scheme using anthropogenic $CO_2$ is the Weyburn project in Canada, which began injecting $CO_2$ in October 2000. $CO_2$ captured in a large coal gasification project in North Dakota, USA is

(34) IPCC Draft Guidelines for National Greenhouse Gas Inventories 2006

(35) IEA GHG R&D Programme, 2001

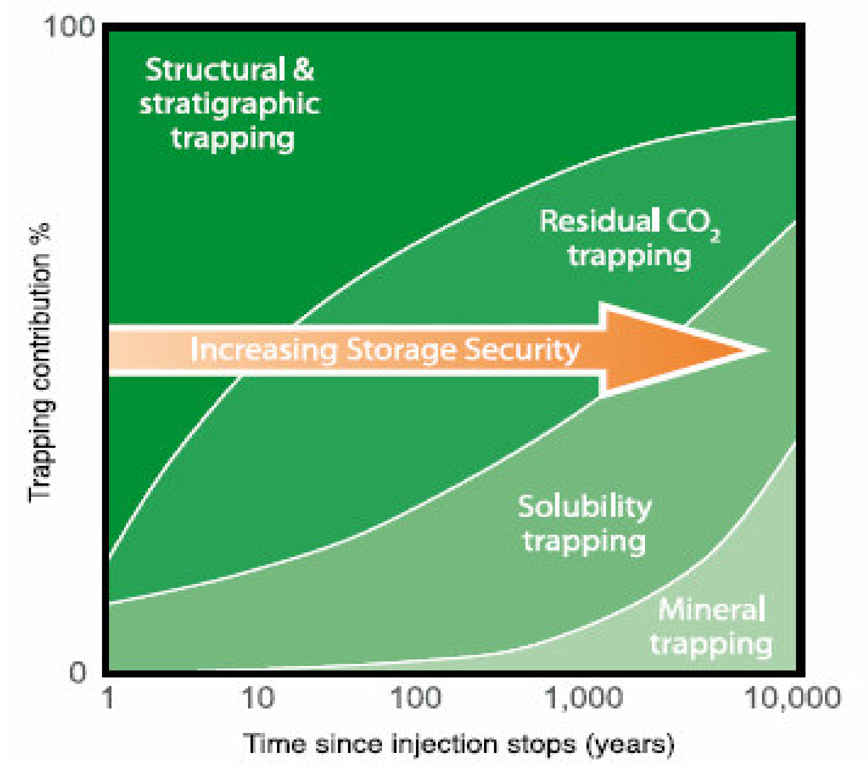
transported 200 miles via pipeline and injected into the Weyburn field in Saskatchewan. During its life, the Weyburn project is expected to produce at least 122 million barrels of incremental oil, through miscible or near-miscible displacement with $CO_2$; this will extend the life of the Weyburn field by approximately 20-25 years.

It is estimated that 50% of the injected $CO_2$ will be permanently sequestered in the oil that remains in the ground, the remainder coming to the surface with the produced oil. From here, it is being recovered, compressed and re-injected. Overall, it is anticipated that a total of 20 Mt of $CO_2$ will be re-injected over a 20 year period. The project will help to assess the technical and economic feasibility of geological storage of $CO_2$ in oil reservoirs and develop implementation guidelines for such projects and identify the risks associated with this method of $CO_2$ storage, especially long-term risks of leakage.

### *A1.5 $CO_2$ TRAPPING MECHANISMS*

Following injection, $CO_2$ is trapped in geological formations by different physical and geochemical mechanisms. The predominant mechanism by which injected $CO_2$ is trapped in storage formations changes over time, with structural trapping being slowly replaced by other geochemical processes. Initially, injected $CO_2$ will be trapped physically by low permeability rocks. Over longer time frames, however, reservoir chemistry will change, with the predominant trapping mechanism moving towards more secure processes, such geochemical methods via formation / rock interactions (*Figure A1.5*). The various physical and geochemical trapping mechanisms are outlined below.

*Figure A1.5 Geological $CO_2$ trapping mechanisms over time*




Source: IPCC SRCCS, 2005.

### *A1.5.1 Physical trapping*

Injected $CO_2$ will initially be physically trapped under a low permeability seal or cap rock (stratigraphic and structural trapping), which the $CO_2$ plume will push up against, acting under buoyancy. Where the $CO_2$ is trapped as a gas above a column of saline water this is known as hydrodynamic trapping.

Other physical trapping methods include:

- *Residual trapping* – $CO_2$ injected into saline aquifers can be trapped as a gas in the pore spaces around grains of rock; and,
- *Absorptive trapping* –where $CO_2$ is adsorbed onto the surface of coal and certain types of shale

Over time, these processes will be replaced with other geochemical mechanisms.

### *A1.5.2 Geochemical trapping*

Over time, $CO_2$ will be increasingly trapped via a sequence of geochemical interactions with the surrounding rock and formation water. These processes will further increase storage effectiveness and security, as well as storage capacity.

In early stages, the predominant geomechanical trapping mechanism is *solubility trapping*, where the $CO_2$ is dissolved into a liquid, such as water or oil that is present in the formations. This reduces the buoyancy of the $CO_2$, preventing further upward migration, and reducing the risk of diffusion into and through the caprock.

Following dissolution, the $CO_2$ can begin to form ionic species and may subsequently be converted to stable compounds/minerals; largely calcium, iron, and magnesium carbonate over periods of several thousand years. Reaction of the dissolved $CO_2$ with carbonate minerals can take only a few days, but the same process is very slow (hundreds to thousands of years) with silicate minerals. This is known as *mineral trapping* and is the most stable storage mechanism.

The ultimate objective of storage site selection – as discussed below (in *Sections 3.2.3, 3.3, 8.2 and 9.5*) – is to find a site which exhibits characteristics which suggest that these mechanisms will be effective over the very long term.

Annex B

# CDM precedents relevant to Baselines

## B1.1 CDM PRECEDENTS FOR BASELINE ACCOUNTING METHODOLOGIES

With respect to the range of issues outlined in the *Section 4.2*, several CDM methodologies can be reviewed for the precedent that they set in terms of determining both baseline scenarios and baseline accounting methods. Key precedents in approved methodologies that are relevant include methodologies covering:

- CCS technologies (in methodologies that have yet to be approved);
- Grid-connected zero and low-emission power plants (similar to power plants with CCS);
- Off-gas emissions abatement e.g. HFC-23 destruction (similar to natural gas production & processing and LNG emissions);
- Retrofits at industrial installations.

The relevant methodologies to consider are summarised below (*Table B1.1*).

*Table B1.1 Summary of approved methodologies relevant to CCS baseline issues*

| CCS leakage issue | Methodology number | Title |
|---|---|---|
| CCS technologies | NM0167 and NM0168 | No precedent actually set. Neither proposed methodology NM0167 or NM0168 consider the unique nature of CCS projects within a sufficiently robust methodological framework. |
| Grid-connected zero- and low emission power plants[A] | ACM0002 ver06 | "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" |
| | AM0029 | "Baseline methodology for Grid Connected Electricity Generation Plants using Natural Gas" |
| Off-gas emissions abatement | AM0001ver04 | "Incineration of HFC-23 waste streams" |
| Retrofits at industrial installations | ACM009 | "Consolidated baseline methodology for fuel switching from coal or petroleum fuel to natural gas" |
| | NM0168 | "The capture of $CO_2$ from natural gas processing plants and liquefied natural gas (LNG) plants and its storage in underground aquifers or abandoned oil/gas reservoirs" |

[A] AM0019 is not considered relevant to CCS projects as it is limited in its scope to unique circumstances which can be covered by alternatives outlined in this report.

Further details on the precedents set in these methodologies are outlined below.

### B1.1.1 CCS technologies

No existing approved CDM methodologies consider the unique issues presented by CCS project baselines. Whilst both NM0167 and NM0168 made useful contributions to considering accounting methodologies for CCS activities, both had some gaps in the approaches to deal with certain items including baseline approaches. The approaches they proposed were:

- NM0167 – which involved the retrofitting of a $CO_2$ capture plant to a newly built gas fired power plant - proposed that the baseline emissions for the project are equal to the amount of $CO_2$ captured and stored in the project activity [(1)], which would otherwise be vented in the absence of the project.

- NM0168 – which involved the retrofitting of a $CO_2$ capture plant to an existing LNG facility to capture knockout $CO_2$ (i.e. capture of reservoir $CO_2$ and $H_2S$ stripped from natural gas prior to liquefaction) – also proposed that the baseline was equal to the amount of $CO_2$ captured and stored, which would have been vented in the absence of the project.

The report of the 22nd CDM Methodologies Panel meeting concluded that neither methodology was adequate or appropriate to address the issues raised by CCS projects. In terms of baselines, both also considered that historical emissions were an appropriate baseline approach by proposing an accounting methodology based on the mass of $CO_2$ captured and stored i.e. they assumed that the baseline is the volume of $CO_2$ captured. As reviewed in *Section 4* of the report, this unlikely to be the case in several applications.

### *B1.1.2 Grid-connected zero- and low emission power plants*

To date, approaches to baseline accounting methodologies for grid-connected power projects have been based on the emissions associated with the type of power plant(s) that the project will displace at the margin (based on the combined margin, which is made up of the build margin and operating margin [(2)] )

- ACM0002 is designed to account for emissions reductions resulting from the deployment of new build grid-connected renewable (zero-emissions) power plants, and uses the combined margin approach. ACM0002 is only applicable to new build greenfield renewables projects, and is not applicable to installations retrofitting renewables at the site of fossil fuel power plants. Indeed, it specifically excludes situations where the "*… project activities […] involve switching from fossil fuels to renewable energy at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site*". This suggests that the baseline accounting methodology for retrofit CCS projects should be based on historical emissions, although this should be limited to "end-of-pipe" retrofits (see *Section 4.3*).
- AM0029 is only applicable to new-build natural gas fired power plants exporting electricity to grids dominated by electricity produced from other more carbon intensive fuels. It is not applicable to repowering or fuel switch projects. It proposes that project participants shall use the lowest for the emissions factor ($EF_{BL,CO2,y}$) for the baseline calculation from among the following three options:
    - *Option 1*. The build margin, calculated according to ACM0002; and

(1) The proposed project boundary in NM0167 did not include the installation producing the $CO_2$.

(2) Build margin = the type of plant that would have been built to add new capacity to the grid in the absence of the project. Operating margin = the type of plant that would have been dispatched to deliver power to the grid in the absence of the project.

- *Option 2.* The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight.
- *Option 3.* The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" in the approved methodology.

More recently, the CDM EB has suggested that project participants using ACM0002 can change the weighting of the OM/BM applied in certain project specific circumstances, to a maximum of 75% either way in the first crediting period (3).

In order to maintain the principle of conservativeness, best practice new-build CCS projects could, therefore, be to utilise the combined margin approach outlined in ACM0002, probably with a 75% weighting on the build-margin as new coal fired plants utilising CCS will likely run at baseload (and therefore have lower impact on the operating margin in a particular grid). New gas-fired power plants utilising CCS might best use a 50/50 weighting as these plants may in some circumstances operate for peak shaving. Project proponents should justify their selection of weightings on a project specific basis, and these should be reviewed in the 2nd and 3rd crediting periods based on actual operating experience.

### *B1.1.3 Off-gas emissions abatement*

HFC-23 destruction projects involve the destruction of off-gas streams from the manufacture of HCFC-22 products. Much concern has been raised about the creation of potential perverse incentives to de-optimise plant operation in order to increase the amount of HFC-23 produced (and subsequently monetise destroyed HFC-23). Therefore, to manage this risk, a narrow scope of applications is defined in the applicability criteria, as follows:

- AM0001 is only applicable to retrofit applications where 3 years of historical HFC-23 emissions data is available in the Period 2000-2004. New-build projects cannot apply for this type of CDM project activity. It also includes a maximum HFC-23 generation rate based on the ratio of HFC-23/HCFC-22, which is capped in the baseline to 3%, or where no historical data are available, 1.5%.

Whilst similar issues could conceivably be posed by bringing on stream very high $CO_2$ gas fields (4), the issues are in fact different for several reasons:

- In HFC-23 projects, each tonne of HFC-23 is equal to 11,700 $tCO_2e$, which is not the case for natural gas processing/LNG production;

(3) Whilst it may seem somewhat perverse to some observers that a CCS power project might need to consider such baseline methodological issues i.e. approaches other than historical emission or emission avoided (as it is highly unlikely that a fossil fuel power project will be built purely for the purpose of monetising stored $CO_2$) it is important that CCS projects are considered the same as other zero-emission technologies.
(4) Some natural gas fields currently under production contain up to 60-70% $CO_2$,.

- The $CO_2$ content of the gas is dictated by natural reservoir conditions, not process modifications (although production rates could theoretically be increased, and more $CO_2$ could be removed in the project scenario in order to increase the baseline in an *ex ante* calculation approach);
- The cost of handling and re-injecting the gas will likely far outweigh the benefits delivered by monetising the injected $CO_2$ under foreseeable carbon market conditions.

As such, there is probably not a need to manage this risk in natural gas and LNG projects. As such, the baseline for the application of CCS to natural gas processing emissions should be the volume captured and stored i.e. the volume of $CO_2$ that would be vented to the atmosphere in the absence of the CDM project activity.

However, in order to ensure completeness, project proponents should consider the following issues when demonstrating *additionality* for natural gas processing projects:

- *New build projects*: that the field would be developed without CCS in the absence of the CDM; and,
- *Retrofit projects*: that there will be no major increases in either $CO_2$ concentration in the field gas or in gas production rates during the crediting period or, if there is, that such increases can be measured and monitored, and accounted for appropriately.

### *B1.1.4 Retrofits at industrial installations*

The relevant methodologies outlined above for retrofit projects (*Table B1.1*) include specific clauses in the applicability criteria to exclude capacity extensions etc. Issue along these lines include:

- ACM0009 is only applicable to existing installations (i.e. retrofits) where the project activity *"does not increase the capacity of thermal output or lifetime of the element processes during the crediting period (i.e. emission reductions are only accounted up to the end of the lifetime of the relevant element process), nor is there any thermal capacity expansion planned for the project facility during the crediting period"* or *"does not result in integrated process change"*. It is not applicable to element processes that generate electricity.
- NM0168 proposes co-injection of $CO_2$ with $H_2S$, and consequently mitigates the need to build and operate an $H_2S$ destruction (incineration) plant. This results in a reduction in the emissions from this particular component in the project scenario relative to the baseline scenario. This is a relevant approach to accounting and must be considered appropriate for the CCS methodology discussed in this report.

The specific applicability limitations identified in ACM0009 are assumed to be a consequence of elements missing from the baseline accounting methodology, rather than strict prohibitions because of CDM eligibility reasons. Many of the relevant issues for CCS projects in this context are reviewed in the main report (*Table 4.1*), and are considered to be workable if the appropriate accounting methodology is applied.

Where additional emission sources may be present in the baseline scenario, but are absent from the project scenario as a consequence of implementing the project e.g. for $H_2S$ destruction versus injection, these emissions should be accounted for appropriately.

Annex C

# CDM precedents relevant to Leakage

## C1.1 CDM PRECEDENTS FOR LEAKAGE ACCOUNTING METHODOLOGIES

With respect to the leakage issues identified for CCS projects (*Section 6.2*), several CDM methodologies can be examined to determine the precedent that they set in terms of determining both leakage scenarios and leakage accounting methods relevant to CCS.

It is important to note that whilst a number of different leakage scenarios have been presented in various CDM methodologies, and some convergence in approaches can be seen, there is presently no consistent approach to dealing with leakage emissions across similar project activity types. As such a comprehensive review of different leakage scenarios and the accounting methodologies presented has been undertaken. The relevant methodologies to consider are summarised below (*Table C1.1*).

***Table C1.1 Summary of approved methodologies relevant to CCS leakage issues***

| CCS leakage issue | Methodology number | Title |
|---|---|---|
| Upstream fuel cycle emissions | ACM0007 | "Baseline methodology for conversion from single cycle to combined cycle power generation" |
| | ACM0008 | "Consolidated baseline methodology for coal bed methane and coal mine methane capture and use for power (electrical or motive) and heat and/or destruction by flaring" |
| | ACM0009 | "Consolidated baseline methodology for fuel switching from coal or petroleum fuel to natural gas" |
| | AM0014 ver 02 | "Natural gas based package cogeneration" |
| | AM0029 | "Methodology for Grid Connected Electricity Generation Plants using Natural Gas" |
| Biomass leakage | ACM0003 | "Emissions reduction through partial substitution of fossil fuels with alternative fuels in cement manufacture" |
| | ACM0006 | "Consolidated baseline methodology for grid connected electricity generation from biomass residues" |
| | AM0007 | "Analysis of the least cost fuel option for seasonally operating biomass cogeneration plants" |
| Enhanced hydrocarbon recovery | ACM0008 | "Consolidated baseline methodology for coal bed methane and coal mine methane capture and use for power (electrical or motive) and heat and/or destruction by flaring" |
| | AM0009 ver 02 | "Recovery and utilization of gas from oil wells that would otherwise be flared" |
| Additional material consumption | ACM0002ver06 | "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" |
| | ACM0007 | "Baseline methodology for conversion from single cycle to combined cycle power generation" |
| | AM0024 | "Baseline methodology for greenhouse gas reductions through waste heat recovery and utilization for power generation at cement plants" |
| | AM0025 | "Avoided emissions from organic waste through alternative waste treatment processes" |
| | AM0026 | "Methodology for zero-emissions grid-connected electricity generation from renewable sources in Chile or in countries with merit order based dispatch grid" |
| Project lifetime issues | - | This issue is currently untested in the CDM. |

| CCS leakage issue | Methodology number | Title |
|---|---|---|
| Electricity market effects | AM0010 | "Landfill gas capture and electricity generation projects where landfill gas capture is not mandated by law" |
| | AM0019 | "Renewable energy projects replacing part of the electricity production of one single fossil fuel fired power plant that stands alone or supplies to a grid, excluding biomass projects" |

The relevance of each is discussed below.

### C1.1.1 *Upstream fuel cycle emissions*

In the relevant methodologies identified above (*Table C1.1*), upstream emissions resulting from fossil fuel combustion in the project activity have been considered as leakage emissions. These types of leakage emissions are associated with the following activities:

i) *Fossil fuel combustion in extraction and processing*: covering $CO_2$ emissions from power plants and mobile plant for various activities at the extraction site e.g. drilling, pumping, mining, coal washing etc.;
ii) *Fugitive emissions in extraction and processing*: covering $CO_2$ and $CH_4$ emissions from flaring and venting in natural gas processing, oil production, $CH_4$ emissions from coal mining etc;
iii) *Fossil fuel combustion in fuel transportation*: covering road transport, pipeline boosters, shipping, liquefaction, regasification, distribution etc.;
iv) *Fugitive emissions in fuel transportation*: covering emissions from leaking pipelines, valves, accidental or operational venting etc.

Accounting for these emissions is only relevant to downstream users of energy products. Where the installation forms part of the fuel cycle (e.g. a gas processing facility) these emissions do not need to be accounted for.

ACM0007, ACM0009, AM0014 and AM0029 all outline similar leakage scenarios related to these activities, and indicate that these emissions could or should be considered as leakage emissions when applying the methodology. Notwithstanding the recognition of these emissions in the appropriate methodology, there are some differences in the way in which they are accounted, as follows:

- ACM0007 indicates that these emissions do not need to be accounted for if the project proponent can demonstrate through estimation that these are a negligible fraction of the baseline;
- ACM0009 indicates that these emissions should be counted, excluding any emissions which may occur in an Annex I country;
- AM0014 includes upstream emissions in the same way as in ACM0009, but includes these in the calculation of project emissions;
- AM0029 adopts a similar approach to ACM0007 and ACM0009, but requires project proponents to net out the baseline $CH_4$ fugitive emissions that would occur in the absence of the project activity, based on the generating mix connected to the grid excluding the project activity, and

consistent with the emissions factor developed to calculate the baseline in the applying the methodology. It also requires project proponents to exclude any emissions arising in Annex I countries, and has an alternative calculation for projects using LNG (1).

ACM008 considers the effects that coal mine and coal bed methane could have on additional coal production. In CCS projects utilising ECBM, this is unlikely to be a relevant issue as the coal would remain unmineable due to the presence of $CO_2$ in the seams, which would present access problems in the same way as for the presence of $CH_4$ in the seams. Indeed, ECBM will only be applicable in seams where technical and economic factors deem the coal as a stranded asset using conventional mining techniques.

Given these precedents, CCS projects will also need to take due consideration of the impacts of the project activity on upstream emissions (2).

### *C1.1.2 Biomass leakage*

Existing methodologies involving biomass use (*Table C1.1*) have accounted for several potential sources of leakage for the following activities outside of the project boundary:

i) *Emissions from fossil fuel combustion in the biomass supply chain*: covering emissions from vehicles used to transport the biomass to the project site;
ii) *Emissions of $CH_4$ arising from anaerobic decay of biomass*: covering decay in landfills which would deliver negative leakage (i.e. positive emission reductions / negative leakage);
iii) *Emissions arising from offsite preparation of the biomass*: covering drying if the biomass is prepared at another installation that is not the project activity; and,
iv) *Emissions arising from fossil fuel combustion at other facilities*: covering situations where biomass supplied to the project may remove biomass from other users, who subsequently resort to using fossil fuel for their operations.

ACM0003, ACM006 and AM0007 all consider these as relevant emissions and there is generally a consolidated approach to handling leakage emissions – albeit with some differences – as outlined below.

(1) The authors actually question the merit of undertaking such detail characterisation of the upstream fuel cycle emissions based on a number of factors including: these emissions are likely to be insignificant relative to the level of effort required to collect the data and the overall emissions reductions delivered by the project; and, there are significant variations in upstream emissions across different sources of fossil fuels of the same type (e.g. coal from high $CH_4$ seams relative to low $CH_4$ seams), In addition,, in many cases where this methodology is applicable, emissions from natural gas production will be significantly lower than for coal production. Moreover, there will be significant uncertainties associated with any estimates arrived at.

(2) Although this form of leakage emissions will need to be based on the incremental change in upstream emissions in the project scenario relative to the baseline scenario (i.e. if the baseline scenario identified in the project involves the use 700,000 GJ/yr of gas, and the project scenario involves the use of 800,000 GJ/yr of coal, then the incremental difference is the upstream coal emissions from 800,000 GJ of coal less the upstream gas emissions associated with 700,000 GJ of gas; this is simplified if the baseline scenario involves the same fuel type). This approach is adopted in AM0029.

- ACM0003 requires proponents to demonstrate that the total amount of biomass fuels available to the project is 1.5 times the amount required to meet the consumption of all users consuming the same biomass fuel. This step is designed to show that there is a surplus of biomass in the specific market relevant to the project. Offsite emissions from biomass transportation are considered as leakage in this methodology, and project proponents are required to account for these emissions. Where biomass was previously landfilled, the methodology allows proponents to generate emissions reductions by accounting for the reduction in $CH_4$ emissions from landfills by the displacement of anaerobic decay of biomass in landfills as a consequence of the project activity. This methodology also considers emissions arising from offsite preparation of the biomass (e.g. drying);
- ACM0006 includes transport emissions and displacement of other users of biomass as a component of the project emissions calculation and as such do not need to be considered as leakage (under certain scenarios). It also requires project proponents to demonstrate that there is an abundant surplus of biomass in the region which is at least 25% larger than the quantity of biomass used in the project activity. The methodology also requires proponents to demonstrate that the biomass has previously been left to decay in the field or has been subject to uncontrolled burning prior to implementation of the project activity (under some scenarios).
- AM0007 also includes consideration of leakage emissions from biomass transport and displacement of other biomass users. It subsequently presents two different options for estimating leakage due to displacement of other users which are different to those proposed in ACM0006 or ACM0007. It does not elaborate a methodology for accounting for leakage due to emissions in the biomass supply chain (i.e. transportation emissions).

To date, various types of leakage emissions in biomass projects have been considered in relevant CDM methodologies, although different accounting methods have been adopted in different methodologies. Consequently, a CCS project involving either pure biomass combustion, or biomass co-firing with coal, will need to take account of any leakage emissions associated with this component of the project.

#### *C1.1.3 Enhanced hydrocarbon recovery*

Existing approved methodologies involving the reduction of fugitive emissions of fossil derived $CH_4$ (i.e. not biogas based projects) and their delivery to market, namely for coalbed (CBM) and coalmine (CMM) $CH_4$ recovery and flare gas emissions reductions, have considered the scope for leakage as a result of taking these products to market.

In CCS projects involving $CO_2$-EHR, there are some synergies with these projects due to the creation of:

i) *Emissions due to the combustion of extra hydrocarbons produced in the project*: covering the combustion of natural gas, oil or coalbed methane due to the use of $CO_2$ for enhanced gas, enhanced oil or enhanced coalbed methane recovery;

ii) *Fugitive and processing emissions associated with the additional hydrocarbons produced*: covering pipeline leaks, flaring, venting etc (as outlined in the previous Section where *Upstream fuel cycle emissions* are reviewed)

To date, the following approaches have been adopted in ACM0008 and AM0009 which bear some relevance with such potential leakage emissions:

- ACM0008 includes the emissions arising from the combustion of CMM/CBM as part of the project emissions. The parallels with $CO_2$-EHR projects are not directly comparable as in CMM/CBM projects, the gas is usually utilised close to the mine itself and is the primary objective of the project activity, whilst in $CO_2$-EHR activities the market is likely to be remote, and in some cases may be a secondary objective of the activity after $CO_2$ storage. It also considers the effects that de-gassing the mine could have on making the new seams available for coal extraction, and the leakage effects this could have on coal markets.
    - For the former, project proponents are required to calculate the extra coal production that the project activity may allow, and then exclude any extra CBM/CMM from these activities from the emission reduction calculation (or apply a 10% discount factor).
    - For the latter, the methodology acknowledges that CER revenues could reduce the cost of coal production and subsequently reduce coal prices. However, the methodology does not propose any methods to resolve this form of leakage, and CDM Meth Panel suggests that the CDM EB should monitor the issue going forward.

  As outlined in *Annex A*, ECBM projects unlikely to take place in seams that could be exploited in the future.
- AM0009 considers a range of additional leakage emissions, including the fuel cycle emissions, and changes due to substitution of fuel at end-users. The former are dealt with by applying the same algorithms as applied in for calculating project emissions. In order to account for the latter, project proponents are required to consider whether additional demand for fuel will be created, and whether the fuels will substitute fuels with a lower carbon intensity. It suggests that market analysis should be undertaken, and if leakage is identified, these should be accounted for in the project (3).

This form of leakage creates the biggest challenge to successfully articulating an appropriate CCS CDM methodology that includes $CO_2$-EHR activities.

Whilst AM0009 suggests project proponents should consider whether additional demand for fuel will be created, it is likely to be virtually impossible to fully characterise and measure the effects of incremental hydrocarbon production associated with a single $CO_2$-EHR project on supply

(3) Note that no method is presented by which this accounting process should be carried out. In reality, it is highly unlikely that any effects on global energy markets could be detectable from small incremental increases in hydrocarbon production.

and demand in global energy markets [4]. Moreover, it is also important to consider various other factors related to $CO_2$-EHR projects, including:

- *Current technology costs and carbon values*: the current status of CCS technologies makes deployment of CCS in today's carbon market very expensive, whilst full cost recovery is unlikely to be achieved through emissions trading alone. Indeed, there are likely to be certain circumstances where CCS $CO_2$-EHR projects are not economically viable, even where the avoided $CO_2$ emissions are monetised and revenues for the hydrocarbon products are realised. However, $CO_2$-EHR could be a good primer for wider deployment for CCS technologies into the future, as additional hydrocarbon production will be able to mitigate project financial risks. Where $CO_2$-EHR projects present economically attractive options in the absence of CDM Registration, then these should not be considered as CDM projects on the basis of financial additionality.
- *Policies and measures to manage hydrocarbon demand*: under the UNFCCC and Kyoto Protocol - as well as national and regional policy initiatives - ongoing measures in many countries should be directed at improving energy efficiency and managing end-user energy demand. Consequently, the rationale for considering these issues in the context of individual CCS $CO_2$-EHR CDM projects is unclear i.e. hydrocarbon demand may be managed by appropriate policies and regulations at the point of use.
- *Hydrocarbon production at the margin*: assuming no new demand for hydrocarbon products is created in $CO_2$-EHR projects, they could potentially displace marginal hydrocarbon production operations. This might include highly emissions intensive oil sands, oil shales, gas reserves with high levels of impurities, or synfuel production without CCS, all of which may be more emissions intensive than the proposed $CO_2$-EHR activity.
- *Economic sustainability*: ensuring high levels of ultimate hydrocarbon recovery from oil & gas fields will be in the economic interest of many developing (non Annex I) country governments. High ultimate recoveries [5] will ensure that domestic hydrocarbon resources are utilised in a sustainable way, reduce dependence on foreign imports, and deliver government revenue in the form of hydrocarbon royalties.

Taking into consideration these points, and that the Marrakesh Accords require leakage to be *measurable and attributable to the CDM project activity*, it seems that measuring the effects on global hydrocarbon demand is likely to be very difficult, whilst attributing the effects to an individual project will be impossible. As such, it is proposed that effects of $CO_2$-EHR not be taken into account as leakage in a CCS CDM methodology.

Notwithstanding the proposal to exclude this form of leakage in a methodology, it is suggested that $CO_2$-EHR issues in CCS CDM projects be considered as part of an *environmental additionality* test presented by the

(4) Especially as the market is not subject to pure economic forces, but also to geopolitical concerns.
(5) Note: new field developments in countries such as Norway require applications to include ultimate recoveries in the order of 55%, OOIP which is only likely to be achieved with miscible $CO_2$-EOR floods.

project proponent i.e. that project proponents must demonstrate that there is a overall net reduction in $CO_2$ emissions across the whole life of the project, including the emissions created by the $CO_2$-EHR activity. Where proponents cannot demonstrate a net reduction in GHG emissions, CCS projects should not be considered as eligible for registration as a CDM project. This concept is explored previous parts of this report where *Additionality* is considered (*Section 5*).

One further challenge for calculating the baseline in EHR projects is what the emissions profile would be in a NFA scenario i.e. what the emissions from the operations would have been under normal operating conditions in the absence of the $CO_2$ flood (see *Section 4.5*).

### *C1.1.4 Additional material consumption*

In the relevant methodologies identified above (*Table C1.1*), emissions arising due to materials consumption have been acknowledged as a potential form of leakage. These include:

- *Emissions due to construction of a power plant*: covering materials use, transport of materials, fuel handling etc.

ACM0002, ACM0007, AM0024 and AM0026 all acknowledge this potential source of leakage emissions, but suggest that they should not considered as they may be negligible. AM0025 outlines that "positive" leakage (6) could occur through displacement of organic fertilisers with mineral fertilisers, but does not account for these.

### *C1.1.5 Project lifetime issues*

Relative to conventional $CO_2$ storage projects, CCS $CO_2$-EHR projects involve additional use of energy (and consequent $CO_2$ emissions) to recapture, compress and re-inject $CO_2$ emerging with the hydrocarbon produced at extraction wells ("breakthrough" $CO_2$). As $CO_2$-EHR projects progress, increasing volumes of $CO_2$ will re-emerge (and less hydrocarbons as the effectiveness of the $CO_2$ flood reduces) and consequently, the specific amount of energy consumption per unit of oil or gas production increases towards the end of the project life (see *Figure 4.2*).

Towards the end of a $CO_2$-EHR project, breakthrough $CO_2$ in some cases could constitute 70-80% of the total $CO_2$ injected, and as such, will require significant volumes of energy to remove the $CO_2$ from the hydrocarbon product, compress and re-inject it. In many cases these emissions will continue to occur (and increase) beyond the end of the CDM crediting period (7) (see *Figure 4.2*)

There are no precedents in the CDM relevant to this issue.

(6) Infact, the correct term should be negative leakage as positive leakage would actually imply an increase in emissions!
(7) Typically an enhanced oil recovery project could last for 30-40 years.

The authors proposed that such issues would need to be considered as part of the *environmental additionality* test identified previously (*Section 5.3.2*). In short, a full carbon mass-balance – including the emissions associated with the combustion of any *incremental* hydrocarbon produced compared to the baseline scenario (see *Figure 4.2*) – across the full project life-time should be undertaken and in order to demonstrate that the project delivers a net greenhouse gas emission reduction i.e. it is environmentally additional.

### *C1.1.6 Electricity market effects*

Some CDM methodologies – as identified in *Table C1.1* – have considered the effects that additional electricity generation could have on electricity demand, principally relating to an increase in demand as a result of project implementation.

AM0010 and AM0019 consider these issues in the following way:

- AM0010 considers that the projects of this type could create new electricity demand as the electricity will be produced at a lower tariff rate [presumably relative to grid electricity where the power is sold directly to users and not to the grid]. The methodology indicates that if the amount of electricity generated by the project is large (8) relative to the total amount of electricity delivered by the grid, then that methodology cannot be used.
- AM0019 suggests that energy prices will not be reduced due to the addition of a renewable energy project and thus there is no risk that it will result in a higher consumption of electricity by the end-users.

Given that the application of a CCS at a power generating plant will increase the levelised generation costs, and subsequently an increase in electricity prices, an overall reduction in electricity demand might be expected as a consequence of a CCS project.

Application of CCS at industrial installations is also unlikely to encourage more profligate use of heat or electricity at the facility. Whilst conceivably a perverse incentive to use more power could be created through CCS application (as the captured emissions would be monetised), the cost of running the $CO_2$ capture plant will not be offset by the incremental revenue created by CERs delivered from any CCS projects (9). Moreover, in *Section 4* – where baselines for CCS projects were considered – it was suggested that the baseline for CCS projects must be based on an equivalent system that is displaced by the CCS project activity (e.g. a reference plant or combined margin approach) and *not* the volume of $CO_2$ captured at the facility. As such, there will not be any perverse incentives to increase the volume of $CO_2$ generated, captured and stored as part of the project activity.

(8) No definition of 'large' is provided.

(9) Figures provided in the IPCC Special Report on CCS (2005) give levelised capture costs in the range US$15-75/t$CO_2$ for power plants, and US$5-55/t$CO_2$ for industrial installations (hydrogen, ammonia or gas processing plants). Typical CER revenues are in the order US$4-6/CER.

Considering the precedent set in AM0019 i.e. that additional electricity demand will not be created by the project activity, this issue is not considered further in this report.

Annex D

# Submitted CCS CDM monitoring methodologies

## D1.1 CDM PRECEDENTS FOR MONITORING METHODOLOGIES

Presently, only NM0167 and NM0168 have considered monitoring methodologies for sub-surface $CO_2$. Both included some suggestions on technologies that should be applied to CCS projects, as briefly reviewed below.

In NM0167, the project proponents outlined the following techniques for the monitoring of the sub-surface $CO_2$ storage site (*Table D1..1*)

***Table D1..1 Monitoring technologies proposed in NM0167***

| **Technology proposed** |
|---|
| *Reservoir monitoring*, covering: |
| • Temperature and pressure of the reservoir; |
| • 3D seismic data before the start of the project and at the end of each crediting period - used to update the reservoir model to check compliance with minimum standards; |
| • Seismic profile well data is collected at the end of each crediting period - used to update the reservoir model to check compliance with minimum standards; |
| • 4D seismic data is collected at the end of each crediting period - estimate $CO_2$ loss and check compliance with minimum standards; |
| • Time lapse 3D seismic data is used to update the reservoir model; |
| • Repeat seismic surveys (4D seismic) to measure amount of stored $CO_2$; |
| • Vertical seismic profile of injection well and (if applicable ) production well; |
| *Well monitoring,* covering: |
| • Vertical seismic profile of injection well(s) and (production well if applicable); |
| • Temperature and pressure of the reservoir; |
| • Injection wellhead pressure; |
| • Annular pressure; |
| • Tubing pressure. |
| *Surface monitoring*, covering: |
| • Soil gas analysis (onshore) and direct water sampling (offshore); |
| • Map the location of sample points, location/number, etc. |

The methodology also outlined some procedural approaches to determining how to arrive at the appropriate monitoring technology and monitoring plan.

NM0168 proposed the following monitoring technologies (*Table D1.2*)

***Table D1.2 Monitoring technologies proposed in NM0168***

| **Technology proposed** |
|---|
| *$CO_2$ escapes from the pipeline and the injection wells*, covering: |
| • Pipeline pressure (both of the flow pressure and the static pressure at the inlet of the pipeline) |
| • Wellhead pressure (both of the flow pressure and the shut in pressure at the head of the wells) |
| • Approaches to Baselines accounting in CCS projects |
| • Annular pressure between the casing and the tubing of the injection wells |
| • Emission in regards to $CO_2$ escaping from the injection wells |
| *$CO_2$ escapes from the reservoir:* |
| • Three dimensional (3D) seismic survey |
| • Downhole monitoring (the flow pressure and temperature, the shut-in pressure and temperature) |

A temporal process flow for considering seepage is presented in the baseline methodology. It proposes that estimates of future seepage can be made at the end of the final crediting period (over 1000 year timeframe), and these emissions would be discounted from the total CERs credited. No ongoing monitoring of the storage site post crediting period is proposed.

### *D1.1.1 Shortfalls in approaches*

Whilst both proposed methodologies highlight some of the technologies that may be relevant to the execution of a monitoring plan, both include several shortfalls with regard to the issues presented above, namely:

- *The outlining of specific monitoring techniques.* Most observers accept that there is not a specific set of monitoring technologies which can be wholly conferred onto all geological $CO_2$ sites. Rather, technologies must be selected according to the aims and objectives of the monitoring plan, and site specific characteristics;
- *The lack of a clear process to define the monitoring programme*. Neither proposed methodology defines an appropriate risk-based process to arrive at the design of an appropriate monitoring plan, outlining specific techniques, locations, and frequencies of observations;
- *Methods to quantify $CO_2$ seepage*. All sub-surface monitoring techniques are limited by the level of detection that they can achieve. It is likely that expert review of sub-surface data will be necessary to convert reported data to a quantified estimates of seepage losses (if any are suggested by the data) (1);
- *Monitoring beyond the crediting period*. Neither proposed approach satisfactorily considered how monitoring for seepage beyond the CDM crediting period might be handled.

These elements must be covered in the design of any sub-surface monitoring plan, as described below.

(1) This a generic issue, although it is not expressly considered in the proposed methodologies.

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