PERMITTING ISSUES FOR CO_2 CAPTURE AND GEOLOGICAL STORAGE

Technical Study

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PERMITTING ISSUES FOR CO_2 CAPTURE AND GEOLOGICAL STORAGE

Background to the Study

The capture and storage of CO_2 in geological formations is a promising technology for reducing greenhouse gas emissions. Such projects will involve very large investments in plant, pipelines, wells and reservoir development. As with most large undertakings it will be essential to obtain permits for a whole range of activities which have to be carried out in order to implement such projects. Obtaining permits has been a major constraint on the rapid deployment of many new technologies and can cause considerable delay and effort even when implementing proven systems. To ensure that CO_2 capture and storage can be deployed successfully in the required timescales any issues that may arise during permitting of CO_2 capture and storage projects need to be identified as early as possible and permitting procedures developed and agreed. This study was commissioned to provide an overview of permitting issues in CCS projects and provide some guidance to operators and regulators who are concerned with the technology.

Approach

Applying for permits for major industrial undertakings can be complex and time consuming. Regulations and permissions can be at national, regional and local level and encompass consideration of a wide range of potential consequences. The main principles of regulation are often common wherever in the world an activity is to take place but actual regulations are specific to countries, regions and even localities. In order to obtain an overview of the permitting issues pertinent to CCS a consultant with global presence was engaged to describe and compare permitting for CCS in a representative selection of countries, highlight gaps, and then draw general conclusions. ERM (Environmental Resources Management) was selected to carry out the study. It was agreed that three regions would be examined in detail, Australia, USA and Europe. This was subsequently increased by inclusion of Canada. Many of the important regulations in Europe are enacted in country legislation and the analysis was done on the basis of UK enactments. Whilst this selection covers predominantly "anglo-saxon" legislations this is not felt to affect the main conclusions.

The consultant was asked first to describe all of the permitting issues which a major CCS project might raise, then to give an overview of the general structure of the relevant regulatory instruments in each of the four chosen areas. Following this a detailed analysis for each area was carried out to identify which issues were covered, partially covered or not yet covered by existing regulations. This is summarized in tabular or narrative form in the main report as appropriate. Where gaps exist the consultant was asked to assess in general terms what regulators were likely to require.

In order to cover the field systematically the permitting requirements were subdivided into those required for each of the 3 main temporal phases:-

- Planning and construction
- Operation
- Closure and decommissioning.

And for 4 elements in the chain of capture and storage:-

- CO_2 capture plant,
- CO_2 transport,
- CO_2 injection and storage to point of well closures
- Long term stewardship of storage reservoir

Results and Discussion

The study has identified the main regulations and permitting procedures which will apply to CCS and where there are gaps the nearest ones which might be applicable or adaptable. This report is a useful source of this information and allows comparison of relevant permitting legislation in the four regions studied. A comprehensive index of the various acts and regulations is included for ease of reference. However, while every attempt has been made to be comprehensive, the legislation identified by the authors of this report should not be taken to be a complete or exhaustive list.

The study highlights the special issues which may need to be addressed during the permitting process when CCS projects are implemented. It examines the need for development of permitting regimes and describes the information which permitting authorities are likely to require in order for the necessary permits to be issued. The table below gives a broad overview of the extent to which CCS projects raise issues for the various phases and elements of CCS and where development of the permitting system is likely to be required.

PHASE ► ELEMENT ▼	Planning & construction	Operation	Closure and decommissioning
Capture	**Minor issues to be resolved**	**No significant issues**	**No significant issues**
Transport	**Minor issues to be resolved**	**No significant issues**	**No significant issues**
Injection and storage	**Significant issues and gaps. Long term stewardship may have to be addressed**	**Ongoing issues, mainly addressed in planning phase**	**Mainly addressed in planning phase and by long term stewardship permitting**
Long term stewardship	**Significant issues and gaps. General requirements may have to be addressed early**	**Significant issues. Requirements may have to be refined.**	**Significant issues and gaps which have to be resolved by this phase**

Table 1 Permitting issues and gaps matrix for CCS

For capture and transport there are, as perhaps expected, few issues and those identified pertain to the planning/construction stage of permitting. There are significant issues for both the injection/storage and the long term reservoir stewardship phase which are not covered by existing permitting systems. Considerable development of legislation and permitting procedures for this activity is thus required. The report suggests that most issues will have to be addressed at the planning/construction stage thereby requiring extensive information to be provided up front on the long term behaviour of the reservoir and wells. There are also important issues associated with the long term stewardship and it is possible that some of these will also have to be addressed well before this activity starts. In the oil and gas industry the conditions for closing wells and relinquishing a reservoir can be formulated at the end of the operational phase of production. It is taken for granted that adequate abandonment methods will be available and that specifying these at the end of operations will ensure that the latest and best technology is used. In the case of CO_2 storage it is possible that initial permits will be granted only on the basis that acceptable well closure and long term stewardship techniques are demonstrated to the satisfaction of the competent authority.
In brief it is a question of whether authorities granting permits for the construction of the underground storage facilities will accept that the plans and techniques to be used when wells are closed and the

period of long term stewardship begins can be formulated towards the end of the injection period. In most cases this would allow several decades for abandonment and long term monitoring technology to develop.

The report also suggests that uncertainties about reservoir performance may result in use of time limited permits for the injection phase, requiring operators to renew permission as reservoir pressure and CO_2 content increases. The diagram below, illustrating the phasing of permits, helps to visualize these timing issues.

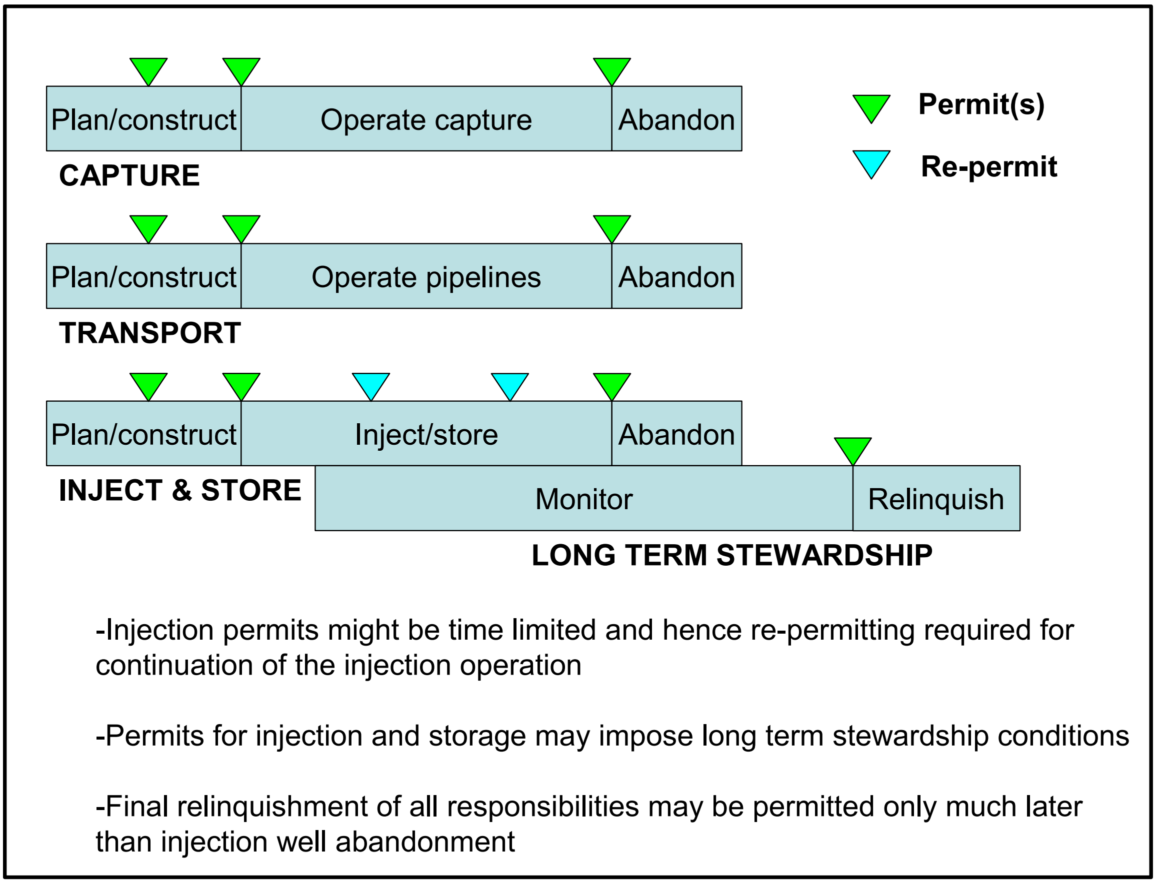


Fig 1.Timing of CCS project permits

Permitting for capture and transport

For CO_2 capture and transport existing regulations in all the jurisdictions studied are largely adequate but there are a few minor gaps and areas only partially covered. The areas where there could be a new issue are listed in the table below with an indication of which jurisdictions might need some amendment or addition to the current permitting arrangements.

Capture and transport permitting coverage			
CAPTURE	**GAP**	**PART COVERED**	**COVERED**
Energy Penalty (acceptable trade offs)	US CAN AUS	UK	
Storage of Amine solutions			US UK CAN AUS
Safety of Equipment (case law may develop)		UK	US CAN AUS
Wastewater discharges			US UK CAN AUS
Change in exhaust parameters (effect on plume)		US UK CAN AUS	
Waste from Amine reclamation		US CAN	UK AUS
TRANSPORT			
Population density (special signage)		UK AUS	US CAN
Removal of Water (specifications)	UK AUS		US CAN
Permitted development rights			UK US CAN AUS
Definition of a Gas (CO_2 to be added)	UK AUS		US CAN
Hazard / risk			UK US CAN AUS

Table 2 Permitting coverage of capture and transport

Table 3 (at end of this overview) summarises the main legislation which would be applicable to permitting of CO_2 capture plant in the 4 jurisdictions considered in the report. This is by no means exhaustive as there are often many other acts and laws covering specific issues. (such as indigenous population rights, heritage sites etc) which also have to be taken into account in the permitting process. This table illustrates that each jurisdiction is concerned with similar effects in the permitting process but, for historical reasons, the laws and mechanisms have been set up differently.

Table 4 summarises key legislation relating to permitting of pipelines. Again the patterns are similar but not the same. This table highlights only the legislation specifically directed at pipelines. In practice a range of other requirements to protect the public and the environment may come into play when obtaining the necessary permits to construct and operate a high pressure CO_2 pipeline especially when it is onshore.

Other surface activities

All jurisdictions were also found to have comprehensive regulations which would allow permitting for surface facilities and activities at the injection site for a CCS project. This includes such items as injection equipment, seismic acquisition and surface monitoring equipment.

Injection and storage

The main underground elements of CCS i.e. the injection wells, the reservoir, its management and long term integrity do require significant development of the permitting process. The report identifies as much as possible of the legislation and procedures which are expected to form part of the permitting process for all phases of CCS. There is a detailed narrative for each of the four jurisdictions considered.

Table 5 summarises legislation which might be relevant to CO_2 injection and storage in the 4 jurisdictions. Petroleum legislation features in most jurisdictions but the main report makes clear that while it could provide a framework such legislation does not directly address many of the issues associated with long term underground CO_2 storage. In the USA the UIC programme, aimed primarily at protecting underground water resources, does provide a framework for most types of underground injection activity. Such a framework does not exist elsewhere. It would however need some adaptation and extension to fully accommodate geological storage of CO_2. This is discussed at more length in the main report.

In Australia a start has been made on new legislation under the Barrow Island act designed specifically to enable CO_2 from the Gorgon project to be stored in an underground reservoir. A general statement has been published as to how regulation of CO_2 storage should be developed in Australia and this suggests a combination of new legislation and adaptation of oil and gas legislation.

In Canada the provincial legislation developed to cover the re-injection of acid gases from petroleum operations is also considered to provide a useful model for CO_2 storage but does not cover all issues.

Permitting frameworks developed for oil and gas and extractive industries give some good indications as to what requirements for long term underground storage of CO_2 are likely to be. This legislation is in most cases the nearest applicable but is aimed at extractive processes which are relatively short term and leave reservoirs depleted. CO_2 storage leaves reservoirs at higher pressure, containing alien material and raises significant new issues of long term stewardship and integrity. While such legislation could be adapted to accommodate some aspects of permitting CCS it is not obvious that this is the better choice which is why new legislation might be preferred.

It is clear from the tables and from the full text of the report that despite some commonalities there are considerable differences in the way permitting and legislation is set up. Even if a common approach to development could be agreed internationally each jurisdiction would still have to implement it to fit in with their existing frameworks.

New permitting requirements

The report examines in some detail the additional information requirements and conditions which might be applied by regulators in order to be granted the necessary permits for the underground elements of CCS. This includes much detail about the nature and predicted performance of the storage reservoir, submission of emergency plans and definition of injection well abandonment designs. Performing environmental impact assessment (EIA) is identified as a key process which will be central to the successful permitting of CO_2 storage activities. A separate study has been commissioned to examine frameworks and information requirements for carrying out EIA on CO_2 storage projects. A number of points arising from consideration of new permitting requirements for CCS are discussed below.

Extent of information required

The report makes suggestions as to the type of information which is likely to be required to be submitted in support of the necessary permits. These form an extensive list and reflect current concerns about proving integrity of storage sites. The amount of information may well be appropriate for first demonstrations of the technology but there is a danger that requirements could be made unnecessarily onerous. Regulation would be best formulated so that it is sufficiently flexible to accommodate advances in the technology. One solution might be to make as much use as possible of Best Available Technologies (BATs) or Best Practice documents which could be subject of regular update.

Degree of prescription

It is not clear at this stage to what extent regulations or standards should prescribe the information which should be provided and methods which should be used. If prescribed in great detail the result might be too prescriptive and innovation will be stifled. On the other hand operators might prefer to know in advance exactly what information they need to collect and generate. The prime purpose of the information provided in support of the subsurface element of a CCS project is to assure regulators of the reservoir integrity and capacity. This requirement could be framed in a functional way so that exact methods are not prescribed. Regulators would then be free to ask for more or less information as they deemed appropriate. Permit applicants also would be free to offer additional information for consideration if they considered that it would support their application. Thus it might be better to formulate regulations on a purely functional basis leaving open the actual techniques which are used. Again these could be laid down in regularly updated best available practices documentation.

Remediation in case of failure

It is suggested in the study report that regulators will require emergency and remediation plans to be in place before permits are granted. These would certainly have to be in place before operating permits were granted but details of these procedures are likely to be called for at the planning stage as they form an essential part of risk mitigation. Remediation could be a very expensive exercise especially if the reservoir has to be depressured with potential loss of CO_2 emission credits unless the CO_2 can be injected into another reservoir. The financial resources needed to accomplish this relative to project revenues may be much higher than those in analogous activities such as oil and gas production where there is no possibility that significant proportions of cumulative sales revenues from past production could be lost. Providing these plans and assurances up front could be a considerable but necessary burden.

Time limited permits

It is suggested in the report that operating permits for filling a CO_2 reservoir might be time limited so that regulators have some control over the point at which reservoirs are abandoned. Applying such a limit increases uncertainty for the operator who may have to curtail storage activities. On the other hand if the time limit is long enough – say 10 years or more - the financial consequences for recovery of investment will be limited. In view of the uncertainty as to the ultimate capacity of a reservoir it is realistic to have some control on continued operation. However this could be accomplished by periodic review of the ultimate abandonment pressure rather than a requirement for a renewed operating license.

Expert Reviewers' Comments

One reviewer felt that the report would be greatly enhanced if the Canadian jurisdiction was included. This was accepted and was added to the scope of the study. Some reviewers felt that the degree of detail particularly for the UK permitting sections was excessive. This information has been retained and to some extent is unavoidable because of the complex history of legislation in this jurisdiction. A number of comments were made on various details and interpretations in the draft report and as far as possible and where agreed by the authors these have been incorporated into the final text.

Major Conclusions

Major effort is required to formulate an effective permitting regime for the subsurface aspects of CCS. It seems likely that initial requirements will tend to be over stringent and extensive until experience has been built up. In contrast existing regulations cover all the above ground aspects of CCS activities well but when applied may raise a few issues for which minor adaptations and interpretations will be required. Australia is well advanced in tackling the development of a permitting regime to enable CCS and some lessons can be learnt from their experience. However there are some good regulations and practices in other jurisdictions which are well worth studying and sharing when developing and applying permitting systems to CCS projects.

Recommendations

Long term environmental impacts

Environmental impact assessment will be a mainstay of the approval process for CO_2 storage projects. It is recognized that the treatment of possible long term effects due to leakage or ground water movement over centuries does not fit into the shorter term perspectives of the EIA process. Further work needs to be done on the methods by which the environmental impacts of these very long term effects are assessed.

Best practices

The development of best practice guidance in support of permitting regimes should be strongly supported. This will enable a sensible transition from the highly cautious approach likely to be adopted for the first CCS projects to a fit for purpose regime which will be needed if and when CCS becomes common practice.

Capture plant	Europe (UK)	USA	Canada	Australia
Main Country or EU Community Level legislation	Integrated pollution prevention and control (IPPC) Directive Large combustion plant (LCP) directive Strategic environmental assessment SEA directive Environmental impact assessment (EIA) directive EU European Trading system (ETS) Directive Seveso II directive Best available technique reference documents (BREF's)	Clean water act (CWA)1977 Clean air act (CAA)1970 Resource conservation and recovery (RCRA) act 1976	Canadian environmental protection act Canadian Fisheries act	Commonwealth environmental protection and biodiversity (EPBC) act (1999) AGO Generator efficiency standard
State/EU state legislation. Examples only where appropriate	Main EU legislation above is coded into each country's laws.	Additional state level requirements. Enforcement and permitting generally at state level.	**Alberta** Environmental protection and enhancement act (AEPEA), **BC** Environmental management act (EMA), **Saskatchewan.** Environmental management and protection act (EPMA) State Fire codes, State Waste management acts	**Victoria** Environmental effects act 1978 **Victoria** Planning and environment act 1978 **Victoria** State Environmental protection policies (SEPP's) **Western Australia** Environmental protection act 1968

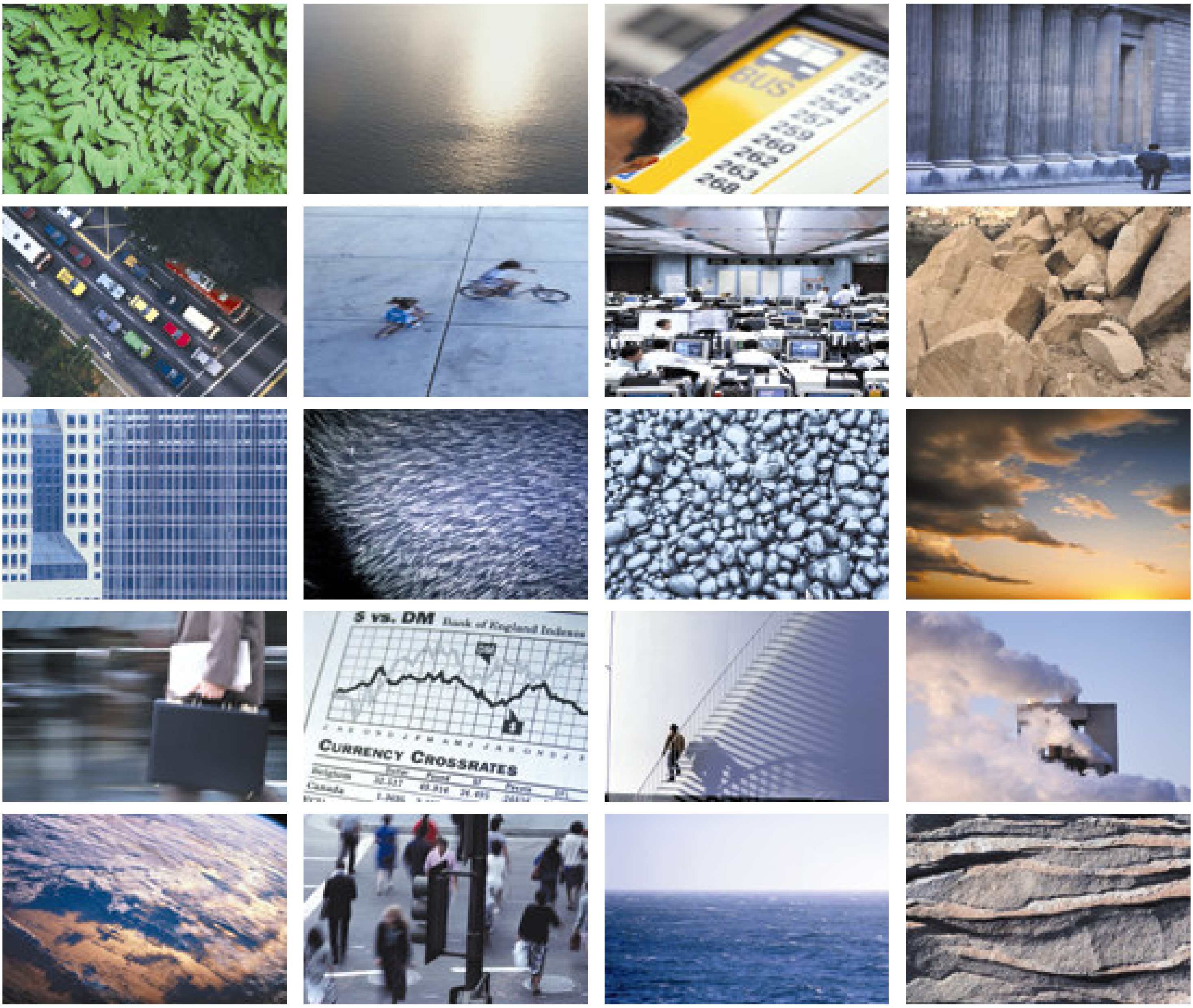
Table 3 Principle regulations forming basis for permitting of capture plant.

Transport	**Europe (UK)**	**USA**	**Canada**	**Australia**
Main Country or EU Community Level legislation		Transport of hazardous liquids by pipeline (DOT 49 CFR 195) National historic preservation act 1966	Federal National Energy Board act (NEBA)	**Offshore** Commonwealth Petroleum (submerged lands) act 1982
State/EU state legislation. Examples only where appropriate	**Onshore** Gas act 1995, Public gas transportation regulations 1999 Pipeline safety regulations 1996 Pressure system safety regulations 1996 **Offshore** Petroleum act 1998 Offshore petroleum production and pipelines regulations 1999 Offshore petroleum activities regulations 2001 The coast protection act 1949 Sea fisheries act 1992		**Alberta** pipeline act **BC** pipeline act Pipelines act (**Saskatchewan**)	**Victoria -** **Onshore** Pipelines act 1967 Pipelines regulations 2000 Gas safety act 1997 **Near Offshore** Petroleum (submerged lands) act 1982 **Western Australia - Onshore** Gas pipelines act 1969 Western **Near Offshore** Petroleum (submerged lands) act 1982

Table 4 Principle regulations forming basis of permitting of pipelines

Injection and storage	Europe (UK)	USA	Canada	Australia
Main Country or EU Community Level legislation	EC Directive (85/337/EEC) Assessment of the effects of certain public and private projects on the environment EC Directive (92/43/EEC) Conservation of natural habitats and of wild flora and fauna Seveso II Directive EC Directive (80/68/EEC) Groundwater Water Framework Directive (2000/66/EC)	Safe Drinking Water Act 1974 (SDWA) and the associated Underground Injection Control (UIC) program National Environmental Policy Act (NEPA)	Canadian Environmental Assessment Act	Draft Guiding Regulatory Framework for Carbon Dioxide Geosequestration Petroleum (Submerged Lands) Act 1967 Petroleum Act 1962 Environmental Protection and Biodiversity Conservation Act 1999
State/EU state legislation. Examples only where appropriate	**Onshore** Petroleum act (1998) Town and country planning act 1990 **Offshore** Offshore petroleum production and pipelines regulations 1999 Food and Environmental Protection Act 1985 Part II (Deposits in the Sea)	UIC implemented at state level but requirements may be more stringent than those of the federal requirements	**Alberta** Environmental Protection and Assessment Act Alberta Oil and Gas conservation act. **BC** Environmental Management Act Environmental Assessment Act. Petroleum and Natural Gas Act, **Saskatchewan** Environmental Assessment Act Environmental Management and protection act Oil and gas conservation act	**Western Australia** Barrow Island Act 2003

Table 5 Principle regulations forming basis of permitting for injection and storage



IEA GREENHOUSE GAS R&D PROGRAMME

Permitting issues for CO_2 capture and geological storage

A review of regulatory requirements in Europe, USA, Canada and Australia - IEA/CON/04/104

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FINAL REPORT

IEA Greenhouse Gas R&D programme

Permitting issues for CO_2 capture and geological storage: *A review of regulatory requirements in Europe, USA, Canada and Australia - IEA/CON/04/104*

November 2005

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For and on behalf of
Environmental Resources Management

Approved by:	Don MacIntyre
Signed:	
Position:	Partner
Date:	7th Deember 2005

GLOSSARY OF TERMS

ALARP - As low as reasonably possible
AGO - Australian Greenhouse Office
BAT - Best available technique
BREF - Best available technique reference manual
CA - Competent authority
CAA - Clean Air Act (US)
CALM - Department of Conservation and Land Management (Australia)
CCS - Carbon dioxide capture and geological storage
CEQ - Council of Environmental Quality (US)
CEQA - California Environmental Quality Act (US)
CFR - Code of Federal Register (US)
CO_2 – Carbon dioxide
COAG– Council of Australian Governments
COMAH – Control of Major Accidents and Hazards Regs (UK)
CRF – Common Reporting Format
CSLF – Carbon Sequestration Leadership Forum
CWA - Clean Water Act (US)
DEFRA - Department for Environment, Food and Rural Affairs (UK)
DfT - Department for Transport (UK)
DMPEG - Dimthyl-ether-polyethelene-glycol
DOE - Department of Energy (US)
DOT – Department of Transport (USA)
DTI – UK Department of Trade and Industry
EA - Environment Agency of England and Wales (UK)
ECBM – Enhanced coal-bed methane
EEC – European Economic Community (now replaced by the European Union)
EES - Environmental effects statement (Australia)
EIA – Environmental impact assessment
EIPPCB – European Integrated Pollution Prevention and Control Bureau
EIS - Environmental Impact Statement
ES - Environmental statement
ELV – Emission limit value
EOR – Enhanced oil recovery
EPA - Environmental Protection Agency (US)
EPBC - Commonwealth Environmental Protection and Biodiversity Act (Australia)
ERMP - Environmental Review and Management Programme (Australia)
ESHIA – Environmental, social and health impact assessment
EU – European Union
EU ETS – European Union greenhouse gas emissions trading scheme
EUA – European Union Allowance (under the EU ETS)
FEPA - Food and Environment Protection Act (UK)
FGD – Flue gas desulphurisation
FONSI - Finding of No Significant Environmental Effects (US)
GES – Generator Efficiency Standard (Australia)
GHG – Greenhouse gas
H_2 - Hydrogen
H_2O – Water/moisture
H_2S – Hydrogen sulphide
HHV – High heat value
SHE – UK Health and Safety Executive
IEA – International Energy Agency
IOGCC - Interstate Oil and Gas Compact Commission
IGCC – Integrated gasification combined cycle
IPCC– Intergovernmental Panel on Climate Change
IPPC – Integrated Pollution Prevention and Control (EU)
JNCC - Joint Nature Conservation Council (UK)
kPa - Kilopascal
LCPD - Large Combustion Plant Directive (EU)
LPG – Liquefied Petroleum Gas
MCEU - Marine Consents Environmental Unit
MDEA - Methyl Diethanolamine
MEA - Monothanolamine
MPa – Megapascal
MPA – Mineral Planning Authority (UK)
MWe – Megawatts electric
N_2O_4 – Nitrogen oxide
NAP - National Allocation Plan (EU)
NEPA - National Environmental Policy Act (US)

NIOSH – National Institute for Occupational Health and Safety (US)
NIEHS - Northern Ireland Environment and Heritage Service
NGO – Nongovernmental organisation
NMP - n-methyl-2 pyrrolidon
NO_2 – Nitrogen dioxide
NO_X – Nitrogen oxides
NPDES - National Pollutant Discharge Elimination System
O_2 - Oxygen
ODPM - Office of the Deputy Prime Minister (UK)
OSHA Occupational Safety and Health Administration
OSPAR - 1992 Oslo and Paris Convention for the Protection of the Marine Environment of the North East Atlantic
PEDL - Petroleum Exploration and Development License (UK)
PEL - Permissible Exposure Limit
PER - Public Environmental Report (Australia)
PGT - Public Gas Transporter (UK)
PON - Petroleum Operations Notice (UK)
PSA – Pressure swing adsorption
RCRA - Resource Conservation and Recovery Act (US)
SARA - Superfund Amendments and Reauthorisation Act
SEA – Strategic environmental assessment
SEPA - Scottish Environmental Protection Agency
SEPP - State Environmental Protection Policy (Australia)
SEPP AQM - SEPP Air Quality Management
SDWA - Safe Drinking Water Act (US)
SO_3 – Sulphur oxide
SO_X – Sulphur oxides
SRCCS – IPCC Special Report on CO_2 Capture and Storage
SRRU – Sulphur removal and recovery unit
TAC - Texas Administrative Code
tCO_2 – Tonne carbon dioxide
TCEQ - Texas Commission on Environmental Quality (US)
TRG - Technical Reference Group
UIC – Underground Injection Control (US)
UKCS - United Kingdom Continental Shelf
UNFCCC – United Nations Framework Convention on Climate Change
WA - Western Australia

See also – Index of regulations / regulators

EXECUTIVE SUMMARY

This report has been prepared by *Environmental Resources Management Ltd* (ERM) for the *IEA Greenhouse Gas R&D Programme*. The report outlines a range of permitting considerations for CO_2 capture and storage (CCS) activities across the full geographical chain of operations (capture > transport > storage) and the temporal dimension of the CCS operational life cycle (planning > construction > operation > decommissioning). The research highlights the key environmental and health and safety regulatory and permitting considerations associated with each element of the chain across the whole temporal cycle. It also provides an analysis of existing environmental, health and safety permitting regimes for large-scale infrastructure projects, and considers the appropriateness of these regulations, given the nature of the permitting considerations for CCS highlighted. Effective regulation of CCS operations will be critical in ensuring that CCS operations can proceed in a safe and environmentally sound manner, and that appropriate responsibilities and liabilities are in place for any impacts associated with CO_2 leakage along the chain, and in particular, at storage sites. A summary of the research findings are outlined below:

Key permitting considerations across the chain

The analysis undertaken suggests that the installation of a CO_2 capture plant at a power plant could trigger additional permitting considerations through several new characteristics of the plant, including:

⇒ changes in the overall thermal efficiency of the plant triggered by the energy penalty imposed by the CO_2 capture plant;

⇒ changes in the exhaust parameters in the plant, which can change the nature of the flue gas plume;

⇒ changes in the concentration of various compounds in the flue gases due to the absence of the dilution effect of CO_2;

⇒ additional considerations for wastewater discharges because of the potential presence of trace solvents from the solvent wash-water line from the CO_2 capture plant;

⇒ additional solid and hazardous waste management considerations from spent solvents sludge;

⇒ occupational health and safety considerations posed by the presence of large volumes of pure CO_2, solvents, and H_2;

These will need to be considered in permitting at the power plant planning phase, and also presents new considerations for power plant operating permits.

For CO_2 transport, fewer additional permitting considerations were found to be critical. Principally considerations relate to:

⇒ higher pressures of CO_2 in dense phase in CO_2 pipelines, relative to water or natural gas pipelines;

⇒ potential additional routing considerations to minimise any asphyxiation risks in the possible event of pipeline leakage;

For CO_2 storage sites, few parallel permitting regimes exist, and consequently a broad range of additional permitting considerations were identified. These include:

- ⇒ permits for undertaking surveying activities for site selection and characterisation, such as well drilling and seismic surveying;
- ⇒ permissions from landowners of the land overlying storage sites. The conferring of mineral storage rights upon storage site developers;
- ⇒ responsibility and liability issues associated with managing any leakage of CO_2.
- ⇒ concerns over ecological and human health risks posed by any leakage of CO_2 from storage reservoirs, both to the air directly above the storage reservoir and into adjacent soil and groundwater;
- ⇒ issues over liability and responsibility for undertaking long-term stewardship of storage sites to ensure that the CO_2 remains safely sequestered. There are also issues associated with trans-boundary sub-surface migration of stored CO_2;
- ⇒ how CO_2 storage sites can be monitored, how [quantified] data on any leakage can be determined and reported, and how this can be incorporated into the permitting process;
- ⇒ how CCS could be included under emissions trading schemes, given the potential for some of the CO_2 to possibly be released to the atmosphere over time, and the 'vintage' issues associated with these emissions, and;
- ⇒ any potential legacy that stored CO_2 could create for future generations, and how this might be managed through an effective permitting process;

Applicability of existing permitting regimes

With these considerations in mind, a review of existing permitting regimes in different jurisdictions - namely the EU (with the UK as a Member State case study), the USA, Canada and Australia - was undertaken. This analysis was focussed on reviewing the nature of permitting regimes for different large-scale infrastructure developments, and assessing their relevance and applicability to the additional considerations identified in the first phase of the research.

This analysis indicated a number of broad conclusions about the applicability of current permitting regimes to CO_2 capture and storage operations. These included:

- ⇒ On the whole, no major additional regulatory developments are required for the permitting of above-ground installations and operations associated with CO_2 capture, transportation and injection activities. The analysis suggested that many of the issues highlighted for this part of the chain could be accommodated through minor adjustments or amendments of existing permitting regimes. This included items such as preparation of statements, permissions for seismic surveying, routing considerations for pipelines etc. In addition, some important lessons can be learned across the jurisdictions under study;

⇒ The energy penalty and thermal efficiency reduction from CO_2 capture could create some new permitting considerations and problems in some jurisdictions. Better guidance for regulators may be necessary, based on national and international environmental priorities, and perhaps adopting some risk~benefit based approach;

⇒ Whilst permitting for pipeline developments are well-established in all jurisdictions, some further guidance may be necessary in terms of the conferring of permitted development rights on CO_2 pipelines. Operational permitting may present new considerations, although important lessons for some jurisdictions can be taken from the US DOT CO_2 pipeline regulations and Canadian Provincial regimes for acid-gas pipelines, for example the Alberta Energy and Utilities Board, regarding pipeline routing, risk assessment, standards and signage.

⇒ No parts of existing permitting regimes can satisfactorily accommodate all issues associated with sub-surface storage of CO_2. Whilst the oil & gas industry has a well-evolved environmental, health and safety permitting regime, this cannot be directly conferred onto CO_2 storage, as the long-term containment of pressurised fluids underground presents a range of new considerations. The US UIC and Canadian Provincial regulations for acid-gas injection present the closest analogue permitting regimes, but these may need to be adjusted to take into account more widespread uptake of CO_2 storage activities. More importantly, no analogous regimes exist in the other jurisdictions under study.

⇒ There is a need for new government-led regulation to ensure safe and secure storage of CO_2 in the sub-surface. Any permitting system developed will need to provide evidence that sufficient assurances and accountabilities are in place to:

- demonstrate that storage site integrity prior to injection i.e. storage site selection, has been carefully considered;
- provide for ongoing performance measurement of the reservoir once injection commences;
- ensure that appropriate responsibilities and commitments are in place with regards to remediation of a leaking storage site;
- ensure that some form of commitment regarding the future site decommissioning and abandonment process has been established;
- ensure that appropriate consideration has been made with regards to long-term liability for the storage site.

The principles for this regime could be led at national, regional or international level via different channels, such as the European Union or the UNFCCC.

⇒ the established Environmental, Social and Health Impact Assessment (ESHIA) process is likely to play a central part in any CO_2 storage site licensing and permitting regime developed.

1 INTRODUCTION

This report has been prepared by *Environmental Resources Management Ltd* (ERM) for the *IEA Greenhouse Gas R&D programme*. The objective of the research was to review the existing regulatory permitting requirements that may be applicable to the full carbon dioxide (CO_2) capture and geological storage (CCS) chain [(1)], and highlight areas where additional regulatory developments may be necessary. Regulatory and permitting issues are critical to ensuring that CCS projects can proceed in a safe and environmentally sound manner, and the appropriate responsibilities and liabilities are in place for any impacts associated with CO_2 leakage across the chain, and in particular, storage sites.

1.1 ONGOING DEVELOPMENTS IN REGULATING CCS ACTIVITIES

The research contained in this report has been prepared during late 2004 and early 2005. Over this period, the subject of CCS, and in particular regulatory aspects of CCS, have undergone significant discussion and evolution. Specific activities have included:

- Circulation of the first and second order draft of the Intergovernmental Panel on Climate Change (IPCC) Special Report on CCS, which will cover regulatory issues, and is due for formal publication late in 2005;
- Joint IEA/Carbon Sequestration Leadership Forum (CSLF) workshop on Legal Aspects of CCS, held in Paris 12-13th July 2004;
- Preparation of a set of regulatory principles for CCS by the CSLF (not yet in the public domain);
- A ministerial level meeting of the CSLF in Melbourne, Australia on the 13-15th September 2004;
- The 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), held in Vancouver on the 5-9th September 2004;
- Policy developments including the Jurist's and Linguist's report and Oslo-Paris (OSPAR) and London Convention developments;
- Various meetings of the UK DTI *ad hoc* group on CCS, including preparation of a position paper on monitoring and reporting of CCS under EU Emission Trading Scheme (ETS) rules (DTI, 2005);
- Publication of the Interstate Oil and Gas Compact Commission task force report (IOGCC, 2005).

The information presented in this report has utilised the team's best knowledge of the dialogue in these arenas at the time of writing. Many of these and other activities remain ongoing, and ERM accept that some information may have been overlooked during the preparation of this report.

1.2 APPROACH

The project has focussed on *additional* permitting requirements in three key jurisdictions:

⇒ Europe, and specifically the United Kingdom
⇒ The United States of America, and;
⇒ Australia

The first phase of the research was to highlight the specific aspects of CCS chains that will need to be considered in developing a regulatory framework. The primary purpose was to identify those issues that present *potential* risks to human health and the natural environment, and draw these out as issues that need to be managed appropriately via the permitting process.

The second phase was then to assess each aspect in terms of existing regulations and permitting procedures within the jurisdictions under study, drawing on the author's expert judgement as to what may apply to CCS, and highlight synergies and gaps within these existing regimes.

The third Phase involved the generation of a range of conclusions about how CCS permitting may be handled going forward both globally, and in the jurisdictions under study.

This research has not undertaken an exhaustive study of all permitting regimes; rather it has focussed on those that are most familiar to the authors based on their experience with environmental permitting across a range of sectors.

Box 1.1 Note on identifying permitting requirements

Within this report some speculation has been necessary regarding which permitting regimes may be applicable to CCS operations. As such, the following terminology has been used:

- ***"will need to be"*** *= already set in existing law and will be applicable*
- ***"likely to be"*** *= expectation that this will become a requirement on operators/developers;*
- ***"may be"*** *= too early to say whether this would be applicable at present*

1.2.1 *The nature of permitting regimes*

The evolution of any major sub-surface infrastructure project, such as oil & gas exploration and production, geothermal field development or development of a new mining operation, poses different sets of environmental and human health considerations across each stage of the project cycle. Development of power plants and gas pipelines above ground are also subject to similar permitting regimes. In parallel, permitting regimes have evolved

(1) Note: This report does not consider potential permitting issues associated with possible oceanic storage of CO_2. Also note: the word storage is preferred in this report, although in some sections sequestration is used, based on the terminology used in the relevant jurisdiction under study.

accordingly so as to reflect and regulate these effects. In summary, these can be considered as:

i) *planning* considerations which permit the commencement of a specific activity. This can also be expanded to consider the impacts of construction activities on the surrounding environment and human populations;
ii) *operational* considerations that permit the continuation of activities in accordance with the relevant planning consent, and/or other regulatory instruments designed to ensure impacts on the environment and human health from industrial activities are minimised, and;
iii) *closure and decommissioning* of the infrastructure associated with the activity following its cessation as a consequence of the depletion of the resource (i.e storage capacity)or injection operations becoming no longer economically attractive.

In the case of CCS operations, a fourth element can be added to this picture, namely:

iv) *long term storage site stewardship* presents another critical element of this study. A critical element will be to understand how a commitment to long-term stewardship of a storage reservoir may be established through storage site permitting following decommissioning. In many cases, it is likely that commitment would be made during site development, with the details of the stewardship programme being established during the decommissioning phase of the project.

Therefore, in order to develop an understanding of the range of permitting issues a CCS chain could trigger, it will be critical to highlight the key impacts at each stage of the CCS project cycle (planning > operation > closure >stewardship), for each element of the CCS chain (capture > transportation > injection and storage). It will also be important to address the differences for geological CO_2 storage sites located on- or off-shore. Regulatory regimes for onshore infrastructure projects are likely to differ from those for offshore activities, and as such are likely to have a different regulatory body or competent authority.

Thus, the key permitting considerations for each element of a CCS chain will be focussed on the *potential* human health and environmental impacts that could arise in the undertaking of the following activities:

⇒ *Installing of CO_2 capture equipment at an stationary installation producing large amounts of CO_2*. This will principally focus on the capture of CO_2 produced at combustion facilities, and how the installation of the equipment could alter the performance of the plant. Changes in plant performance could impact on *planning* authorisation for a proposed power station development, and also on the way *operating* permits are authorised for existing facilities. The actual capture plant may also present additional environmental and human health risks which could trigger additional permitting considerations;

⇒ *Transportation of captured CO_2 in pipelines.* Issues related to the construction of pipelines for conveying pressurised gases are well understood from experiences with natural gas and CO_2 in EOR operations in the U.S. In many countries, *planning* regulations for gas pipelines are highly evolved and CO_2 pipelines are unlikely to present many new considerations, although the issue will be explored. Consideration of the *operational* issues for CO_2 pipelines will also be made. This will draw heavily on previous experiences with existing CO_2 pipelines in the Permian Basin in West Texas.

⇒ *Injection and storage of pressurised CO_2 in sub-surface geological formations* (1). Permitting of a geological CO_2 storage reservoir is a critical element of this research. This will focus on how site selection can effectively identify secure storage sites, the range of operational issues for reservoir monitoring during filling, and the decommissioning and long-term stewardship of the reservoir. There are only a few precedents that can be used to draw parallels with the potential *planning* and *operational* permitting considerations for storage sites (such as the UIC Programme in the USA). In general, the closest analogue permitting regimes are those in existence for the oil & gas, geothermal, underground fluids injection and extractive industries. Consideration of groundwater regulations for onshore locations will also be a major consideration. Oil & gas regimes may present analogues in relation to the selection and development of geological CO_2 storage sites; permitting regimes for the extractive industries may provide further information on how longer-term stewardship of sealed geological storage sites may proceed.

In considering each stage of the CCS chain, it is important to bear in mind the *potentially* hazardous properties of CO_2, and the effects that its release could have on the surrounding environment (*Box 2.1*).

(1) Consideration of detailed occupational health and safety issues will not be made in this review, other than in general terms.

Box 1.2 CO_2 as a hazard

Whereas atmospheric CO_2 poses no threat to human health or the environment under normal ambient conditions (i.e. at concentrations below 1%), it can harm humans at considerably higher concentrations. For instance, CO_2 at concentrations above 2% has strong effects on respiratory physiology and CO_2 at concentrations above 10% can lead to unconsciousness and, at worst, death.

Human health dose-response relationships are well characterized for adverse health outcomes of excessive occupational exposures in environments where CO_2 is a significant hazard (e.g. breweries). However, these relationships may not be relevant for exposures of sensitive sub-populations, such as children and individuals with chronic respiratory diseases.

In terrestrial environments, CO_2 leakage to the near-surface atmosphere will affect biologically active areas. Increased soil concentrations of CO_2 affects root development and water and nutrient uptake from the plant. Natural analogues show that sudden release of high levels of CO_2 can result in vegetation death. In marine environments, the affects of low-level acidification of benthic environments through CO_2 leakage are poorly understood. However, these fragile ecosystems could be at risk in the event of CO_2 seepage.

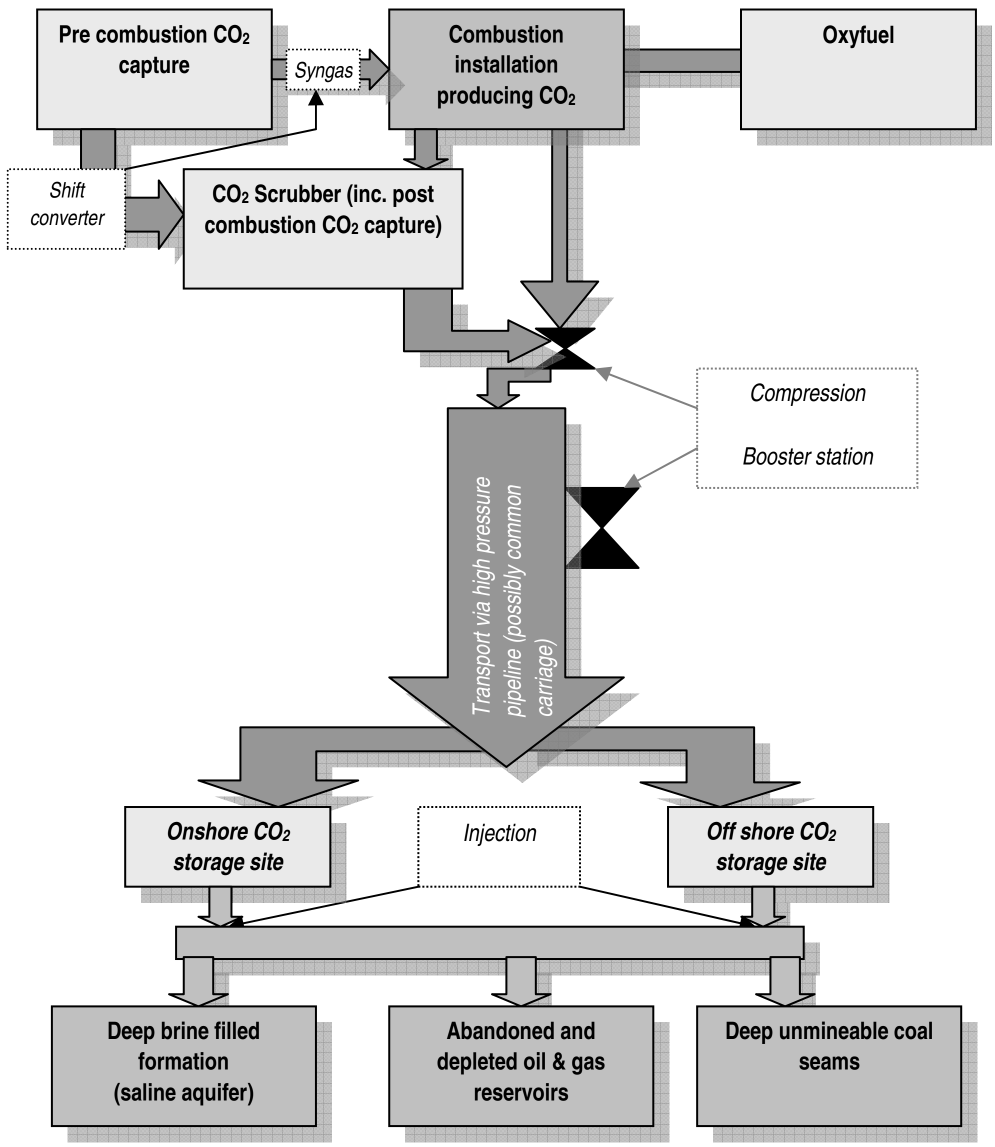
Under most ambient conditions, CO_2 emitted from a source rapidly diffuses (within minutes) to near-background concentrations. However, under stable atmospheric conditions, accumulation of CO_2 to levels several times higher than the atmospheric background could occur, resulting in risk of asphyxiation. The Table below outlines some more information on existing exposure limits for CO_2.

CO_2 Concentration		**Notes**
0.08 – 0.1%	(800-1000 ppm)	Perception of stale air starts
0.5%	(5,000 ppm)	UK HSE long term Occupational Exposure Limit
1.0%	(10,000 ppm)	US NIOSH Personal Exposure Limit for 8-hour time weighted average
1.5 – 3.0 %	(15,000 – 30,000 ppm)	Electrolyte imbalances and other metabolic changes in humans
1.5%	(15,000 ppm)	UK HSE short term Occupational Exposure Limit
3.0%	(30,000 ppm)	US NIOSH Short Term Exposure Limit
>3.0%	(30,000 ppm)	Increase in respiration noted in some human subjects
5.0 – 10.0%		Impaired physical and mental ability and possible loss of consciousness.
>10.0%		Severe symptoms, rapid loss of consciousness, and possible coma or death with prolonged exposure.
>25.0 – 30.0%		Loss of consciousness within several breaths, death imminent

Data from: Woodhill Engineering Consultants (2004)

The proceeding sections outline the characteristics of each technical element of a CCS chain based on typical roadmap from capture to storage (*Figure 1.1*)

Figure 1.1 Roadmap of CCS technologies across the CCS value chain



1.2.2 *Aims and objectives*

The principal aim of the work is to highlight synergies and gaps in the existing regulatory framework that is applicable to CCS. The output is designed to assist CCS project developers to understand their regulatory duties under current frameworks, and highlight to policy makers and regulators areas where developments will be needed to resolve current uncertainties in the regulatory framework.

In order to achieve this, ERM set objectives to:

⇒ Develop a generic CCS project template highlighting the key permitting issues to consider at each stage of the CCS project cycle across each element of the CCS chain;

⇒ Speak with a selection of CCS practitioners in order to develop a better insight into permitting practicalities on the ground related to each technology;

⇒ Review existing permitting regimes for major infrastructure projects and assess their applicability for CCS technologies and processes;

⇒ Highlight gaps in the regulatory regimes that currently do not address specific CCS technology related issues;

⇒ And based on the research undertaken, develop an understanding of the possible critical path for a permitting CCS project (although due to the vagaries of the existing permitting frameworks, this has only been partially possible in some jurisdictions).

1.3 REPORT STRUCTURE

The report is set out in the following format:

Section 2 – outlines the range of permitting issues to consider for CO_2 capture;
Section 3 - outlines the range of permitting issues to consider for CO_2 transportation;
Section 4 - outlines the range of permitting issues to consider for CO_2 storage;
Section 5 - highlights some general permitting considerations in the jurisdictions under study;
Section 6 – outlines permitting considerations for CO_2 capture in each of the jurisdictions under study;
Section 7 – outlines permitting considerations for CO_2 transportations in each of the jurisdictions under study;
Section 8 – outlines permitting considerations for CO_2 storage in each of the jurisdictions under study;
Section 9 - presents the conclusions arising from the research findings.

References used to compile the study are also included.

2.1.1 Overview

CO_2 can be captured from a variety of stationary sources, but the economics of the process dictate that efforts be focussed on the largest sources. Typical emissions for major industrial sources are shown below (*Table 2.1*).

To date, the greatest attention has been focussed on power generation, as this represents by far the largest point source of industrial CO_2 emissions. In line with this trend, the research presented in this report considers the permitting issues presented for CO_2 capture from power generation sources.

Table 2.1 Global CO_2 emissions in major industries

Source	CO_2 emissions Mt/yr
Power generation	7660
Iron and steel production	1440
Cement production	1130
Oil refining	690
Petrochemicals	520

Source: Gale, 2002

For power generation activities, three principal technologies are widely considered as being the most promising for capturing CO_2 in the near term, namely;

- Post-combustion capture;
- Pre-combustion decarbonisation capture; and,
- 'Oxy-fuel' firing (*Figure 1.1*)

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 H_2 for ammonia manufacture. Oxyfuel firing technologies are still at an early stage of research and development. A description of each of these technologies is outlined below:

2.2 CO_2 CAPTURE PROCESSES AND TECHNOLOGIES

2.2.1 Post-combustion CO_2 capture

Post combustion technologies involve the scrubbing (removal) of CO_2 from the flue gas mixtures exiting a combustion plant. The most common application of this technology is to pass the flue gas through a chemical solvent which absorbs the CO_2 fraction.

While absorption into an alkaline solution is the most common application in use today (DTI, 2003), there are a number of other processes that can be employed to remove CO_2 from gas streams. These include:

⇒ Physical absorption into a non-reactive solvent;
⇒ Membrane permeation;
⇒ Adsorption onto a solid;
⇒ Methanation (not suitable for oxidising conditions present in flue gases)

The choice of process depends upon the composition and charactertics of the gas stream, and in particular the CO_2 partial pressure (*Table 2.2*).

Table 2.2 ***Processes for removing CO_2 from gas mixtures***

Process	Gas Flow[1]	CO_2 Partial Pressure[2]
Physical absorption into a solvent	High	High
Absorption into an alkaline solution (e.g. amine)	High	Low
Membrane Permeation	Low	High
Adsorption onto a solid	Low	Low
Methanation	Low	Low

Source: adapted from DTI 2003; [1] A high gas flow is considered over 150 m^3/s; [2] A high partial pressure is considered over 7 bar

The low partial pressure and high gas flows associated with power station flue gases mean that at present, absorption into a chemical solvent presents the only feasible post combustion option in the near term.

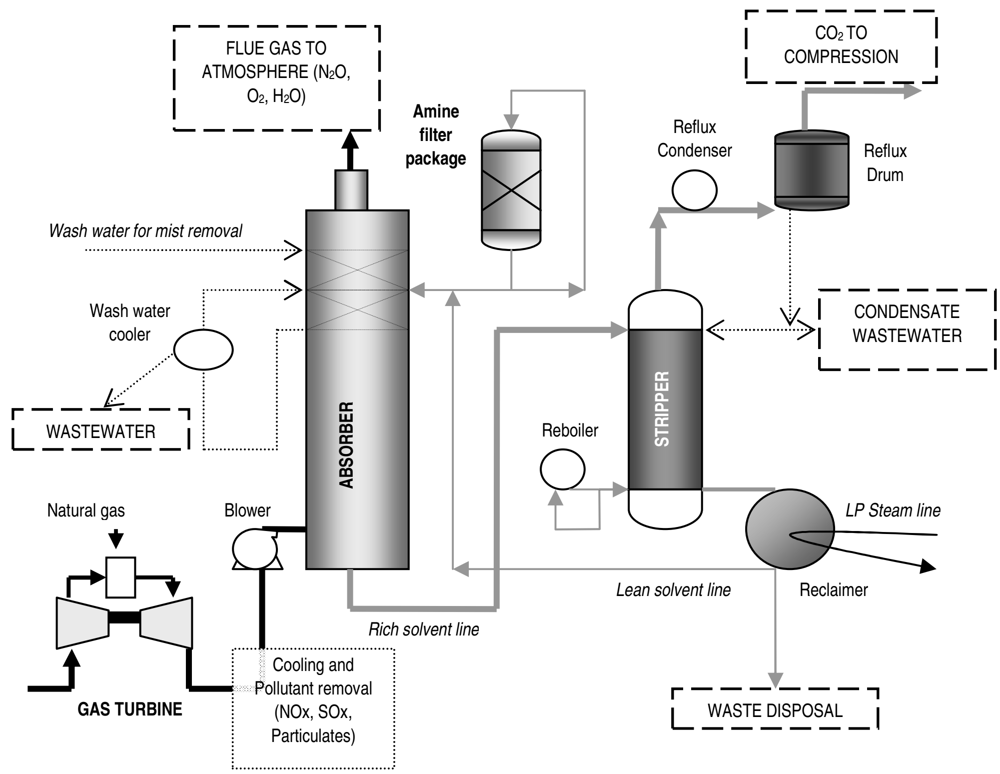
A typical post combustion configuration of this type consists of several stages as follows:

i) *Pre-treatment and cooling* of the flue gas – typically to around 50°C - and removal of particulates and other impurities such as SO_X. Both of these can be achieved in a spray-mist type wet flue-gas desulphurisation (FGD) system;
ii) transfer to an *absorption vessel* containing a chemical solvent -typically an aqueous solution of alkanolamines such as monothanolamine (MEA) – which is suitable for capturing dilute CO_2 at atmospheric pressure. In such solutions, most of the CO_2 in the flue gas will absorbed into the solvent by reacting with it to form a loosely bound compound;
iii) *removal of the CO_2 rich solvent* from the bottom of the vessel and transfer to another vessel (a stripper column). Here the solvent is heated with steam at atmospheric pressure to around 100-140°C to *reverse the CO_2 absorption reaction.* This steam is typically from the steam cycle in the power plant, thus reducing overall plant efficiency;
iv) *Drying* and *compression* of the released CO_2 ready for transport;
v) Recycling of the CO_2-free solvent back to the absorption vessel (*Figure 2.1*)

Similar types of amine-based CO_2 capture processes have been widely applied for a over half a century in the oil & gas industry, primarily for removing H_2S and CO_2 from natural gas streams, and the technology is commercially proven. Most of these plants are generally far smaller scale than that needed to capture the volumes of CO_2 associated with a large power station flue gases.

To date, the process has been applied at several power stations, mainly in the USA. The largest plant in operation is the *IMC Global* plant at *Searles Lake*, *California*. This plant captures some 800 t CO_2 per day from the coal-fired onsite boiler which is then used for carbonation of brine at the Trona soda ash plant. This compares with around 10,000 tCO_2 per day typically produced by a 500 MW coal-fired power plant (1)

Figure 2.1 ***Simplified gas turbine CC with chemical solvent post combustion CO_2 capture***



Based on: Gale, 2002. VGB (2004), Roberts (2002)

Some of the limitations of post-combustion amine scrubbing are outlined below:

2.2.1.1 *Current drawbacks of post combustion technologies*

Problematically, whilst amine based solvent absorption of the combustion gases presents the most practicable and well developed option for CO_2 capture from conventional new-build power plant and retrofit in the near term, a number of drawback in the process exist, namely:

(1) Assuming 80% load factor, 33% conversion efficiency, and 96.1 tCO_2/TJ for sub-bitumous coal.

⇒ *the energy penalty*. There are significant energy demands associated with running the auxiliary equipment for capture, solvent regeneration, compression equipment etc. Estimates put the total energy penalty for post combustion capture in the following bands:

7.7 - 12.6% for pulverised coal-fired plant
6.4 – 8.1 % for coal fired IGCC plant
7.9 – 12.1% for gas fired combined cycle plants

⇒ *the low concentration of CO_2 in the flue gas stream*. Typically combustion flue gas concentrations of CO_2 are around 4 – 15% CO_2 by volume for gas and coal fired plants respectively. Consequently, very large capture plants are required to treat the total flue gas stream. To date, no plants bigger than 800 tCO_2 per day have been constructed. Some observers have suggested that absorber plant of 20-30 m in diameter with capacities of up to 8 000 tCO_2 per day are feasible, which would be of the order necessary for a 500 MWe coal fired plant (VGB, 2004);

⇒ *the potential need to re-pressurise and re-heat flue gases exiting the absorber*. This may be necessary to prevent condensing and corrosion of the flue, and maintain plume characteristics that ensure satisfactory dispersion of pollutants, aerosols and remaining flue gases;

⇒ *problems associated with corrosiveness and acid formation in the absorber, stripper and associated pipework.* High oxygen content in the flue gas can cause oxidation of amines to carboxylic acids, leading to solvent loss and corrosion problems. SO_X in the flue gas also reacts irreversibly with amine to produce corrosive salts also leading to solvent loss and the need to dispose of waste salts. Installation of FGD equipment can mitigate the problem, and tends to outweigh the costs of amine loss (VGB, 2004). NO_X, in particular NO_2 and N_2O_4, can lead to amine degradation and the formation of nitric acids in the absorption plant at levels greater than 20 ppm(v), although this is generally higher than NO_X levels in modern combustion plant flue gases. The formation of acids leads to amine degradation, and subsequently a requirement for disposal of corrosive salts, as well as leading to corrosion in the actual capture plant;

⇒ *high corrosiveness of amine-based solvents to steel in the presence of heat and oxygen.* Because of the corrosiveness of amine-based solvents, they are conveyed in an aqueous solution to reduce their strength. This reduces the overall absorption capacity of the solvent, requiring larger absorber sizes [(1)];

⇒ *the need to handle large volumes of alkaline solvents such as amine*. This could trigger a range of environmental and occupational health control requirements;

⇒ *the need to handle solvent-containing wastewaters*. Wastewater from the absorption tank demister and waste condensate arising from the reflux condenser and reflux drum all need to be treated prior to release to the environment. The presence of SO_3 also creates a highly corrosive sulphuric acid aerosol mist in the flue gas, and must be treated and disposed of appropriately in the washwater wastes;

(1) A number of alternative, less corrosive solvents are under development based on sterically hindered amines.

⇒ *The need to handle hazardous wastes, such as waste solvents containing contaminants and corrosive salts*. Waste solvents will need to be treated, perhaps by incineration. The choice of on- or offsite incineration will be an important consideration for plant operators, although it is worth noting that estimates of waste production are in the order of 10's – 100's tonnes per year for a full scale plant (VGB, 2004). Solid residues from the amine filter plant will also need to be handled appropriately.

2.2.2 *Pre-combustion decarbonisation and CO_2 capture*

As a consequence of some of the drawbacks posed by post combustion capture, a significant body of research effort has been afforded to pre-combustion CO_2 capture. In pre-combustion CO_2 capture, the carbonaceous proportion of the input fuel is removed prior to combustion. The key stages involved in pre-combustion capture of CO_2 are outlined below:

i) production of a *syngas* from the input hydrocarbon fuel (natural gas, pulverised coal), consisting mainly of CO and H_2. This is accomplished through either steam reforming or partial oxidation (with air or pure oxygen) of the fuel in an appropriate reactor vessel. This requires temperatures in excess of 850ºC;
ii) further reacting of the syngas with steam in a catalytic *shift converter*, according to an exothermal water shift reaction to produce CO_2 and more H_2;
iii) for fuels where sulphur is present, it can be subsequently *recovered* from the shift converter exit gases in its pure elemental state using physical solvents in a sulphur removal and recovery unit (SRRU);
iv) the gas from the shift reaction, which consists of between 15-60% CO_2 (dry) by volume, is passed to a CO_2 capture plant where a physical adsorbent is used to remove the CO_2 from the stream.
v) The H_2 rich fuel is subsequently combusted in a combined cycle gas turbine to produce power.

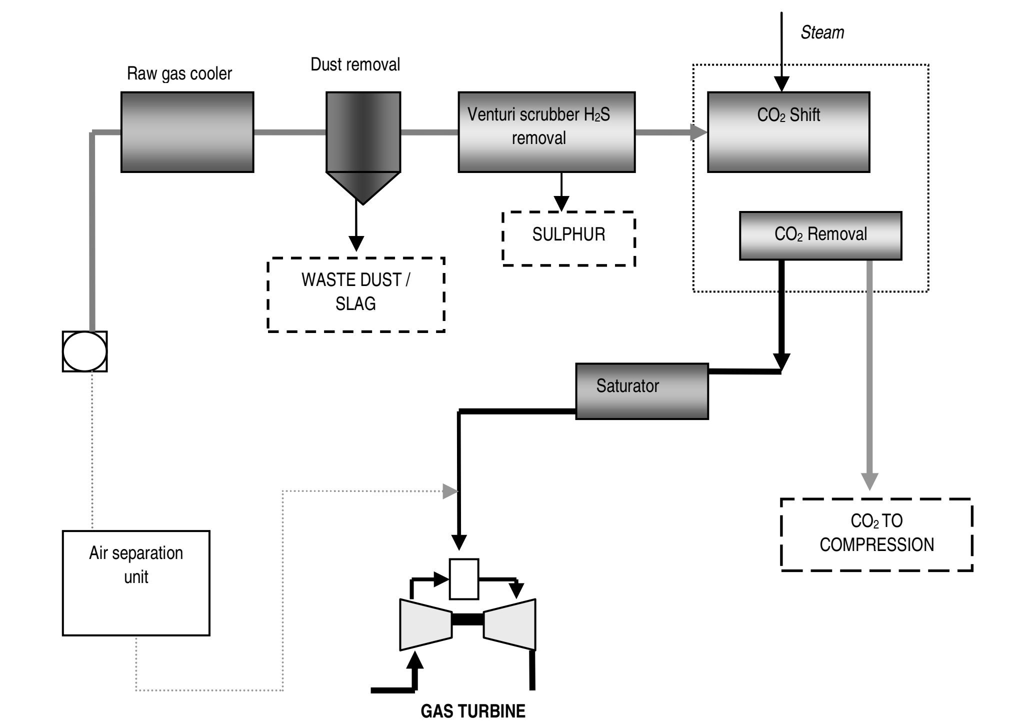
Pre-combustion CO_2 capture has significant advantages over post combustion capture, principally because of the higher CO_2 concentration and higher partial pressure of the gas train sent to the CO_2 removal plant. This means that CO_2 capture is possible using lower volumes of solvents, whilst adsorbents, such as dimthyl-ether-polyethelene-glycol (DMPEG), methanol, n-methyl-2 pyrrolidon (NMP) and propylene-carbonate can be used. These adsorbents have the advantage of only needing to be expanded at low pressures to release the CO_2, avoiding the need to heat the rich solvents line. Membrane technologies and pressure swing absorption can also be applied to pre-combustion processes for the separation of H_2 and CO_2.

These types of technologies are commercially proven for ammonia production and other industrial processes, as well as in coal-fired integrated gasification combined cycle plants (IGCC) and natural gas reforming plants; several IGCC plants have been developed, although the technology is not widespread.

Natural gas reforming and partial oxidation plants are widespread in the chemical industry, albeit at smaller scales than required for power generation.

Gasification technology also greatly reduces emissions of SO_2, NO_2 and particulates. Production of H_2 from fossil fuels in pre-combustion processes also presents a potential bridge to facilitate the transition to a hydrogen-based economy.

Figure 2.2 Simplified diagram of an IGCC plant with pre-combustion CO_2 capture



2.2.2.1 *Current drawbacks of pre-combustion capture technologies*

IGCC and gas reforming plants have suffered from some operational difficulties, and significant scope remains to optimise system design. Principal drawbacks include:

⇒ *Complexity of the plant design.* The multiple stage process requires complex integrated designs. This leads to high costs and reduced plant availability relative to conventional designs. A number of competing gasifier designs are currently under development;
⇒ *Combustion properties of H_2.* The flame properties of H_2 are different than that associated with conventional gas turbine designs. This requires modification to existing turbine designs to accommodate the higher combustion temperatures and flame speed associated with H_2 combustion;
⇒ *Gasifier slagging.* IGCC plants have suffered from the problem of gasifier slagging, and R&D is required to overcome these operational difficulties;
⇒ *Integration of the air-separation unit.* Optimum designs for integrating the air separation unit need also to be developed, in order to minimise costs and increase reliability.

All these areas are the subject of ongoing R&D activities.

2.2.3 *Oxy-fuel Firing*

The low CO_2 concentration in flue gases from traditional air combustion process is one of the greatest constraints on widespread application of post combustion CO_2 capture processes (as outlined in *Section 2.2.1*).

With conventional combustion in air, the inert nitrogen in the atmosphere passes through the burners and boilers, effectively as ballast. Typically, the proportion of CO_2 in the exhaust of a steam generator will be 14% for pulverised fuel coal firing, 8% with oil firing and 4% when fired by natural gas. This can be partially overcome through the application of pre-combustion capture, although the technology is yet to be proven at the commercial scale.

Because of these potential limitations, oxy-fuel firing is proposed as an alternative. In oxy-fuel firing, purified oxygen is used for combustion instead of air, resulting in a flue gas consisting largely of CO_2 and steam. The steam can be readily separated from the flue gas, which in the optimum case leaves a flue gas consisting of 90–95% CO_2 (by weight).

A number of applications of oxy-fuel firing (including the use of direct heating in Rankine or Brayton cycles) have been proposed. The focus for this research is the use of indirect heating in power generation, as this application involves the minimal modification of existing technology developed for the combustion of carbonaceous and hydrocarbon fuels in air.

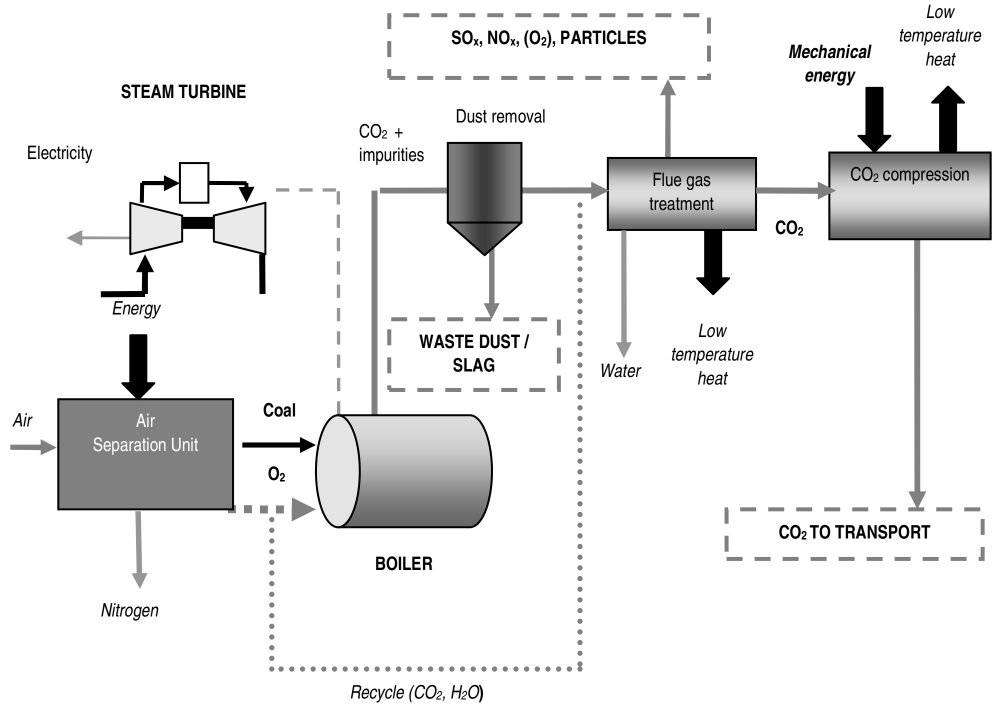
Oxy-fuel firing involves the production of oxygen, which is used in the combustion chamber with the fuel. The exhaust gas, with a high CO_2 concentration, is purified and subsequently compressed to remove water in order to be suitable for transportation. The typical configuration consists of the following stages:

i) *production* of the oxygen – today the only proven technique for large-scale oxygen production is cryogenic air separation, in which air is compressed to approximately 5 bar and cooled to a dew point of -180°C. It is possible to reduce energy consumption through production of O_2 of about 93%, as this removes the need to remove the argon fraction;
ii) *combustion* of the hydrocarbon or carbonaceous fuel. This is typically undertaken in a mixture of pure oxygen and a proportion of recycled 'CO_2 rich' flue gas, which is necessary to reduce combustion temperatures in the turbine. The flame temperature in the combustion chamber is therefore fixed by the proportion of recycled flue gas; in a pure oxygen environment the flame temperature could reach 3 500°C, thus a reduction in flame temperature is required in order to be compatible with current heat tolerances of the combustion chamber construction materials;

iii) *removal* of impurities (O_2, N_2, argon NO_x and SO_2) from the flue gas using a low temperature (-55°C) purification plant;
iv) *drying* and *compression* of CO_2 ready for transport.

Although elements of oxy-fuel 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 5000 tO_2 per day, suitable for a 300 MWe coal-fired plant (VGB, 2004).

Figure 2.3 Oxy-fuel Pulverized Coal-Fired Power Station



2.2.3.1 *Current Drawbacks of Oxy-fuel firing*

The principal limitation for oxy-fuel firing is that cryogenic separation is currently the only method through which large quantities of oxygen can be produced. Current plant sizes range up to 5 000 Mt/day O_2 which would be large enough to support a 300 MWe coal-fired power plant, however O_2 production plants of this size consume a significant amount of energy. Modelled performance data suggest that for an oxy-fuel pulverized coal-fired power station generating 718 MWe (gross), the oxygen plant would consume 103 MW. Therefore R&D into oxygen production technologies with lower energy consumption is necessary before commercial deployment. The energy penalty, in addition to the lack of existing commercial operations, represents the largest technological hurdle. Other potential drawbacks include:

⇒ *engineering requirements to retrofit oxy-fuel firing.* Boiler air 'in-leakage' can be a major obstacle to retrofitting existing boilers, where air 'in-leakage' rates may be in the order of 8 – 16%. In addition to 'in-leakage', other engineering considerations include fitting flue gas recirculation and heat recovery. Oxy-fuel firing is considered a technically feasible option for existing or new boiler plants, however retrofit is not an option for existing combined cycle gas turbines, and further development is required to develop an oxygen fired gas turbine;

⇒ *changes in properties and volumes of fouling and slagging.* Early research has suggested that the fouling and slagging rates may increase using oxy-fuel combustion of coal;

⇒ *high cost of energy penalty*. The production of O_2 through cryogenic air-separation techniques are prohibitively expensive at present;

⇒ *high combustion temperatures.* The combustion temperature in oxygen rich air is significantly higher, and demands new materials development for turbine blades etc. It also means that a significant volume of flue gases must be recycled to reduce the combustion temperature. This can also create a significant energy penalty

⇒ *removal of impurities in the gas stream.* Impurities such as oxygen, nitrogen, argon, NO_x and SO_2 are likely to be removed using a low temperature purification plant. Acceptable levels of removal are yet to be established and therefore engineering requirements and limitations have not been identified. Some observers have raised the possibility of transporting and storing SO_2 with CO_2, since they have similar physical properties; however this has yet to be thoroughly examined.

The oxy-fuel firing process is recognised as an emerging technology, and several demonstration units are expected to be commissioned within the next few years.

2.3 PERMITTING CONSIDERATIONS

The installation of CO_2 capture at a power plant poses a number of considerations for permitting:

- The energy penalty imposed by the installation of CO_2 capture-related equipment (e.g. flue gas strippers, IGCC related plant, cryogenic air separation) will need careful consideration in the context of permitting of new plants during the *planning* phase. Some permitting regimes may set minimum efficiency standards for existing and new-build power plants.
- Application of post-combustion capture will alter the plume characteristics, possibly reducing its buoyancy because of reduced temperature and altering dispersion characteristics. Reducing the overall volume of flue gases will increase the specific concentrations of certain pollutants in the flue gas stream, which could trigger new permitting considerations
- For some configurations, the need to treat hazardous amine and acidic wastewaters will pose new *operational* considerations for effluent discharge permitting, the need to store and handle strong solvents such as MEA could also trigger additional onsite occupational health and safety considerations;
- The possibility of having to construct an incinerator for disposal of hazardous solvent-based wastes will also trigger new *planning* and *operational* permitting requirements.

However, such additional regulatory requirements can generally be accommodated within the existing permitting framework (e.g. planning, safety, health and environment). This may require slight amendments to existing regulations in order to accommodate inherent changes to power plant performance presented by CO_2 capture.

Box 2.1 Permitting Considerations example: Energy Penalty

The implementation of a CO_2 capture technology at a facility will incur an energy penalty. This is not only due to the requirements of the actual process itself, but also because of the need for other ancillary equipment such as reducing the temperature of the exhaust gases, removing impurities etc. The energy penalty will need careful consideration by regulators, and will no doubt require top level government policy or direction which balances the need for energy efficient industry against reductions in emissions of greenhouse gases.

An example of energy efficiency standards is the Generator Efficiency Standards (GES) (1) in Australia. The GES is a voluntary Commonwealth Government / utility agreement which applies to new power plants and existing plants over 30MWe. The agreements state that affected plants must meet the following efficiency standards:

- *natural gas plant: 52% (HHV)*
- *hard coal plant: 42% (HHV)*
- *brown coal plant: 31% (HHV)*

Similarly, under IPPC (2) an installation is required to meet a set of basic energy requirements that are detailed in Sections 2.7.1 – 2.7.2 of the relevant Sector guidance notes. The basic energy requirements include:

'Provision of information on energy consumed or generated by the activities within the permit and the associated direct or indirect carbon dioxide emissions.'

In addition the IPPC H2 Guidance notes that energy efficiency is one of several considerations to be taken into account when determining best available techniques for the prevention and minimisation of pollution. In the case of a trade-off between increased energy consumption and improvement of other environmental objectives, the Operator should undertake an environmental assessment, taking into account the costs and environmental benefits, to justify selection of the best available techniques for preventing and minimising pollution to the environment as a whole. The preferred methodology for this is provided in 'IPPC H1: Horizontal guidance on Environmental Assessment'.

Table 2.3 summarises some of the key permitting issues raised by CO_2 capture processes and technologies.

(1) Adapted from the presentation 'The Australian Scene' presented by Brian Ricketts, UK Coal PLC at the Carbon Dioxide Capture and Storage Mission to Australia Dissemination Event, DTI 2004.
(2) Source: Horizontal Guidance Note IPPC H2 'Integrated Pollution Prevention and Control (IPPC) Energy Efficiency' Environment Agency 2002.

Table 2.3 Issues relevant to permitting presented by capture

Issue	Description
Energy Penalty	The additional energy penalty, particularly when equipment is retrofitted, and resultant reduction in energy efficiency, will require justification using the environmental benefits methodology under some permitting regimes.
Amine solutions	Storage of hazardous chemicals.
Safety	Corrosion of equipment, maintenance monitoring programme, high-pressure systems, hazardous chemicals.
Wastewater discharges	Presence of solvents in wastewater lines from the CO_2 stripping plant.
Change in exhaust parameters	Lower temperature exhausts (post-combustion capture) will result in a decrease in thermal buoyancy of a plume and therefore decrease dispersion. Similarly decreases in exhaust velocities will reduce plume rise and decrease dispersion characteristic of existing operations. These may offset benefits from reducing pollutant concentrations in exhaust gases. This is likely to require an impact analysis and change in discharge permit.
Waste from Amine reclamation	No specific permitting requirements (they are on the process not the waste generated) however a 'duty of care' is likely to exist to ensure that hazardous wastes are transported and disposed of in an appropriate manner.

3 PERMITTING ISSUES FOR CO_2 TRANSPORTATION

3.1 INTRODUCTION

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 to transport CO_2:

⇒ High pressure pipelines; and,
⇒ Marine transport using liquefaction.

3.2 TECHNOLOGIES FOR CO_2 TRANSPORT

3.2.1 High pressure pipelines

CO_2 transportation in high-pressure pipelines is a widely employed technique for transporting CO_2 for the purpose of Enhanced Oil Recovery (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 man-made 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 t CO_2/y, and companies such as Kinder Morgan are considered to be leaders in the development and application of CO_2 pipeline technology.

3.2.2 Ship transport

Marine transport offers a more flexible alternative to CO_2 transportation than high-pressure pipelines. Experience from the Liquefied Petroleum Gas (LPG) industry could be used in the establishment of a large-scale CO_2 marine transport infrastructure, since the transportation conditions for LPG have similarities with CO_2. Due to limited demand, only small scale CO_2 marine transport has taken place to date.

3.2.2.1 Current Drawbacks of CO_2 Transportation

The most critical issue for CO_2 transport is water removal. CO_2 in the presence of water is corrosive to mild steel and therefore it is a fundamental requirement to transport the CO_2 in a dry state, making it virtually inert. Dense phase CO_2 is an excellent solvent, which means that even modern seals are permeable to small amounts of CO_2, potentially posing problems for gas leakage along valve stems etc.

The impact of a CO_2 leak is likely to be much less hazardous than a natural gas leak, as CO_2 is not flammable or explosive. CO_2 readily disperses in turbulent air and has a higher density than air, therefore it is only in situations where air is stable and the topography is such that CO_2 can 'pond' or 'pool' that a significant hazard can occur. In these instances, depending on the concentration, CO_2 may act as an asphyxiant (*Box 1.1)*.

In many parts of the world, it is also likely that significant initial investment would be required to establish a high pressure CO_2 pipeline infrastructure. In populous areas, such as Western Europe, the costs for such an investment could be significantly higher than in other areas (e.g. Australia and the USA).

High-pressure pipelines have the advantage of providing a continuous flow from the emission source to the final storage site. Marine transport would require development of intermediate storage infrastructure to handle the loading and reloading of CO_2 at harbour. This is likely to take the form of large above-ground pressurized steel tanks which are an addition to infrastructure costs as well as representing further health, safety and environment risks. Such developments may also be necessary at injection wellheads in order to be able to regulate flow into the reservoir.

3.3 PERMITTING CONSIDERATIONS

As with CO_2 capture, additional requirements for regulation can generally be accommodated within the existing regulatory framework (e.g. planning, safety, health and environment).

In the UK, no CO_2 pipeline infrastructure currently exists. Given the relative population density of the UK (and Western Europe) compared to USA and Australia pipelines are likely to be in closer proximity to buildings and populations. Public opposition to more pipelines may develop, and it may become more difficult to secure pipeline rights-of-way in highly populated zones. Existing experience has been in zones with low population densities (e.g. Permian Basin in the US), and safety issues will become more pronounced in populated areas.

Table 3.1 Issues relevant to permitting presented by transportation

Issue	**Description**
Population density	Higher population density in Western Europe resulting in pipelines in closer proximity to buildings / populations.
Removal of Water	CO_2 transported needs to be 'dry' otherwise the mixture can be corrosive.
Permitted development rights	Do the existing permitted development rights for natural gas infrastructure development cover flows other than natural gas?
Definition of a Gas	Definition of CO_2 as a gas under gas transportation acts.
Hazard / risk	Risk level deliberation of CO_2 when transported.

4 PERMITTING ISSUES FOR GEOLOGICAL STORAGE OF CO_2

4.1 INTRODUCTION

The principal aim of geological storage is the sequestration of captured CO_2 over long periods of time to prevent its release to the atmosphere. As such, it presents the key stage in any CCS chain as leakage of CO_2 could render climate change mitigation objectives futile, and potentially pose risks to surrounding human populations and the environment (Section 4.3). Several options have been presented for the geological storage of CO_2, as outlined below.

4.2 GEOLOGICAL STORAGE OPTIONS

CO_2 can be injected at high pressure into permeable sedimentary, salt formations or even possibly igneous geological formations with the presence of sufficient pore space for gas storage. The most economic method is to select formations at sufficient depth for the CO_2 to remain in the dense phase in the reservoir. In most cases, dense phase CO_2 is less dense than the existing formation fluids, meaning that it will tend to exhibit buoyancy and flow upwards in the formation. Consequently, target storage formations should be characterised by good vertical sealing so as to restrict or prevent upward migration of the injected CO_2 plume. Although rock structures containing hydrostratigraphical traps, such as depleted oil and gas reservoirs, are thought to be most suitable, recent modelling carried out has shown that horizontal rock structures may also be suitable for CO_2 storage (EU JOULE II). In some 'non-sealed' formations, the rate of migration of CO_2, coupled with the rates for solubility, ionic and/or mineral trapping of the CO_2 mean that release back to the atmosphere is not likely to occur for all the injected CO_2, and could only occur over very long (geological) timescales for the non-trapped portion, if at all.

Many observers suggest that with careful identification of appropriate geological formations, CO_2 can potentially be securely trapped underground for very long periods of time (exceeding millions of years). The key mechanisms necessary for safe storage to be achieved include:

⇒ trapping below a confining layer of caprock which is impermeable to dense phase CO_2.
⇒ hydrodynamic trapping as a consequence of groundwater flows around the reservoir;
⇒ retention as an immobile phase trapped in pore spaces within the storage rock formation;
⇒ dissolution of the CO_2 into the *in-situ* formation fluids;
⇒ adsorption to organic matter where present (such as in deep coal and oil shale formations);
⇒ reaction with the surrounding bedrock to produce mineral carbonates;

In addition, most observers agree that storage sites should be deep (>800m), and shallower rock basins (<800m) are unlikely to prove suitable as:

⇒ deeper structures mean CO_2 can be stored in the supercritical phase, increasing storage capacity. Storage in the gas phase is unlikely to be economically viable due to reduced reservoir volumes, and;

⇒ shallow formation often form important sources of groundwater used for potable supply.

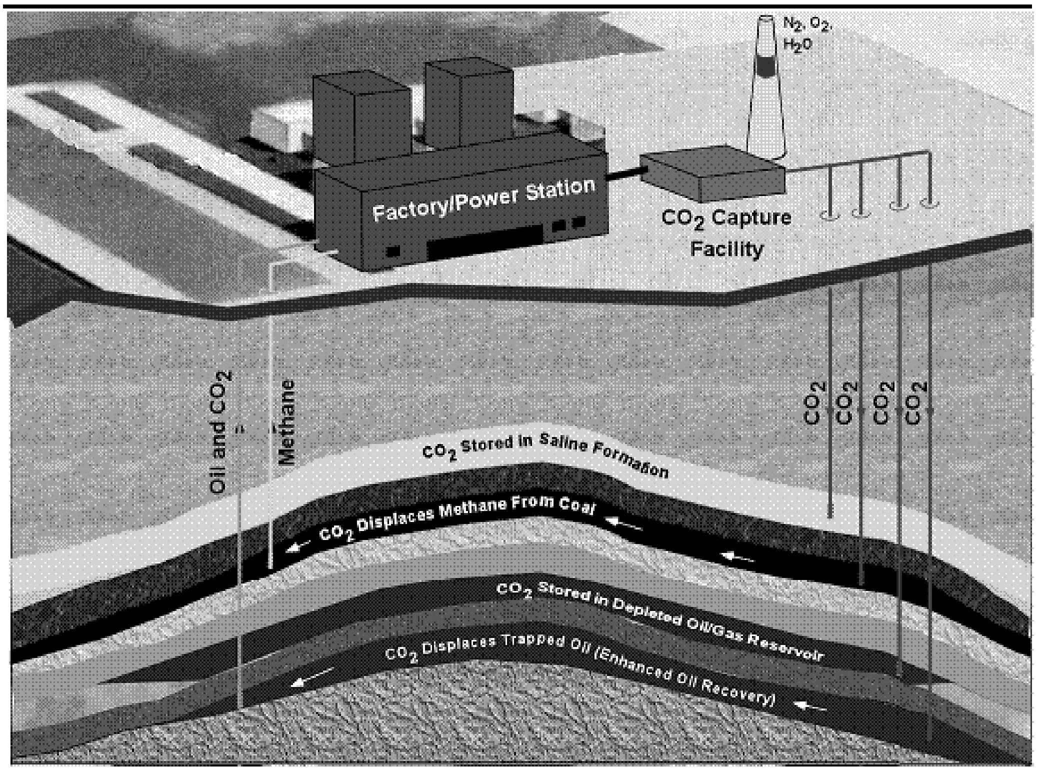
Based on these criteria, three main options for geological storage have been widely recognised:

⇒ Operational and depleted hydrocarbon reservoirs.

⇒ Deep brine saturated formations (saline aquifers).

⇒ Unmineable coal-beds. (*Figure 4.1*)

Figure 4.1* *Main options for geological storage of CO_2



Source: CO_2 Capture Project, 2004.

The following sections describe each of the three storage options in more detail.

4.2.1 Operational and depleted hydrocarbon reservoirs

Of the three storage options outlined, depleted and almost-depleted oil and gas reservoirs present the most immediate storage options in many areas. Moreover, the use of almost-depleted oil reservoirs may have additional benefits in facilitating the extraction of oil from mature fields through enhanced oil recovery (EOR).

In an undisturbed state, oil and gas reservoirs have also demonstrated the capacity to store pressurised fluids over geological time (i.e. have a low caprock permeability and good lateral seal integrity). Furthermore, knowledge gained during exploration and production activities will have led to a good understanding of the specific characteristics of the geological formation.

However, it is important to note that these sites may also be characterised by the presence of a large number of well bores, which could increase the overall risk of CO_2 leakage.

4.2.2 *Deep brine filled formations*

Deep saline aquifers may represent a more suitable option in the long term, as they are thought to provide a better geographical spread and have significantly larger storage potential than any other geological storage options.

Two basic types of deep saline aquifers exist: closed and open aquifers:
- *Closed aquifers* have defined restrictions shaped by geological folding or faulting. This considerably reduces the possibility for lateral movement and slow seepage of CO_2 into overlying potable aquifers or to the surface. This makes them the preferred option for onshore storage.
- *Open aquifers* present a larger storage potential, but they are extensively flat or gently sloping formations of water-bearing rock in which CO_2 can move laterally. Nevertheless, the slow rate of transport combined with their large size means that the gas will be confined for many centuries, and possibly permanently.

CO_2 can be immobilized in both types of aquifers upon dissolution into the formation water, thus reducing buoyancy effects and by reacting with minerals to form solid compounds. However, it is unlikely that all CO_2 injected into a saline aquifer could be trapped in this way, and a large proportion (maybe 50%) will remain as dense phase CO_2 (Benson, 2004; Chevron, 2005).

4.2.3 *Unmineable coal seams*

Unmineable coal seam storage capacity relies on coal's preferential absorption of CO_2 over previously absorbed methane. The adsorption of the CO_2 then prevents its release, unless the coal bed is depressurized.

As methane is mobilised in the process, this option has the potential to yield financial advantages through recovery of the desorbed methane, a process known as enhanced coal bed methane (ECBM). However, further research on the mechanisms of this displacement is required and the use of unmineable coal seams as a storage option is largely at the research and exploration stage. Also, there is a need to ensure that displaced methane is not released to the atmosphere, as it has a global warming potential 21 times that of the CO_2 that would be stored in its place!

The efficacy of unmineable coal seams as geological stores depends on the permeability of the coal seam. It is unusual for coal to exhibit high permeability to CO_2 (e.g. coal in NW Europe has relatively low permeability). Nevertheless, highly permeable coal has the potential to store more CO_2 than a conventional sandstone gas reservoir of comparable size and porosity.

A major concern with this type of geological store is the fact that coal is known to swell in the presence of CO_2, which will further reduce the permeability of the seams. Fracturing has been proposed as a solution, although the extent and duration of the resulting increased permeability is unknown at this stage.

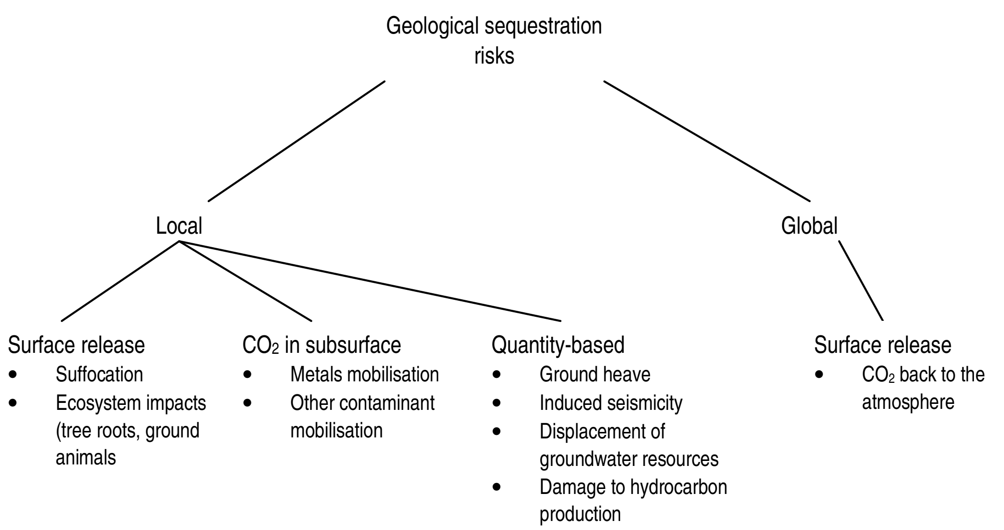
For all storage options, exploitation for the purpose of storing of CO_2 will involve a number of project phases; from site selection through to site stewardship post-filling and abandonment. Each phase will trigger different regulatory issues that will need to be taken into consideration during any storage site permitting. These are discussed below.

4.3 PERMITTING CONSIDERATIONS

4.3.1 Introduction

Poor performance or failure of a geological CO_2 storage facility will render the objectives of any CCS chain project futile. Moreover, migration of CO_2 from its intended storage destination can have other effects on the adjacent environment and human populations. The nature of these risks have been classified by Wilson and Keith (2002) as outlined below (*Figure 4.2*).

Figure 4.2 Taxonomy of possible risks of geological sequestration



Source: Wilson and Keith (2002)

Therefore, because of this critical role in the CCS chain and the broad range of possible risks it poses, geological storage of CO_2 is also the most contentious element of the CCS debate (1). Concerns have been expressed over a number of issues that CO_2 storage sites potentially present, including (see also *Figure 4.2*):

i) the actual effectiveness of CCS as a global climate change mitigation strategy, based on concerns over *potentially* leaky storage reservoirs and the release of CO_2 back to the atmosphere ("Global" risk highlighted in *Figure 4.2*);
ii) questions over what period of time constitutes *secure* storage of CO_2, and consequently what is an acceptable level of storage site integrity,
iii) concerns over the ecological and human health risks associated with any leakage of CO_2 from storage reservoirs, both to the air directly above the storage reservoir and into adjacent soil and groundwater;
iv) issues over liability and responsibility for undertaking long-term stewardship of storage sites to ensure that the CO_2 remains safely stored. There are also issues associated with trans-boundary sub-surface migration of stored CO_2, which have also triggered concerns over responsibility for stewardship, and liability for any damage caused;
v) how CO_2 storage sites can be monitored, and how [quantified] data on any leakage can be determined and reported;
vi) how CCS could be included under emissions trading schemes, given the potential for some of the CO_2 to possibly be released to the atmosphere over time, and the 'vintage' issues associated with these emissions, and;
vii) any potential legacy that stored CO_2 could create for future generations, and the how this might conflict with the overall principles of sustainable development.

Furthermore, whilst such concerns have been raised, there are few analogous processes and systems against which CO_2 storage can be compared. Where comparisons have been made, they often raise spectres such as the nuclear waste issue or large-scale mine development. The closest analogue activities can generally be considered to be oil & gas exploration and production, natural gas storage, acid gas disposal, injection of liquid wastes, geothermal energy exploration and the injection of oil field brines.

Thus, the range of considerations that need to be taken into account through regulation for geological storage site permitting/licensing are both:
⇒ *divergent*, as there are wide range of strongly held views about the acceptability of CCS as part of a climate change mitigation strategy, and;
⇒ *novel*, as no directly analogous regimes are in existence.

Notwithstanding such concerns, there is an emerging consensus amongst a broad range of stakeholders that CCS presents an acceptable technology which can help to stabilise atmospheric CO_2 concentrations over the medium term. However, to achieve acceptability, a regulatory regime must evolve which can serve to effectively manage the different risks presented by storage sites.

(1) And oceanic storage is considered even more contentious, although has not been considered in this study.

The following sections set out to open up this debate by outlining:

⇒ the different steps involved across the project cycle for a geological CO_2 storage site, and;
⇒ the range of permitting issues presented by each step in the project cycle. The range of permitting issues for geological storage reservoirs has already been touched upon in previous sections of this report. These issues are essentially a response to the nature of potential risks posed by geological storage of CO_2 (Figure 4.2). From a permitting perspective, it is important to also consider how these risks pan-out across the geological storage project cycle, as discussed below.

These issues are explored in greater depth in the following sections.

4.3.2 *The project cycle for geological storage*

The project cycle for a geological CO_2 storage reservoir involves a number of different steps, as follows:

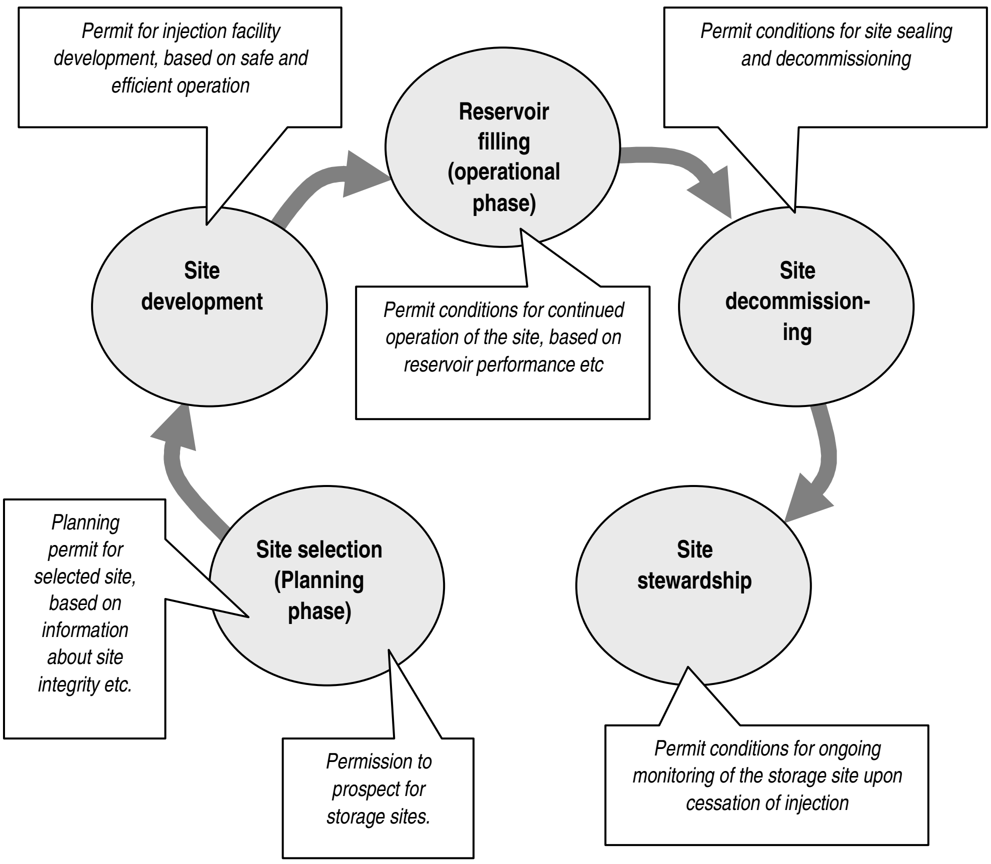
i) *Storage site selection.* The identification and selection of a storage site will be the first phase of a geological storage site development. A number of factors are likely to be taken into account at this point, in particular the compilation of a robust body of geological information that suggests that the injected CO_2 will not leak over an *acceptable* period of time (the definition of that must also be considered). A number of other factors need also to be assessed at this stage, such as the level of risk posed by proximity of the site to human populations, sensitive habitats, or potable water supplies, and the necessary permissions to undertake surveying of the potential storage site;
ii) *Injection facility development*. Once an appropriate site has been identified, the second phase will be the construction of injection facilities and the supporting infrastructure such as observation well bores (the site development phase). A number of permitting considerations will need to be made at this stage which can ensure safe operation of the injection facility, including relevant permissions for the drilling of observation wells at points outside the immediate vicinity of the injection facility site (although a number of these sites may be established under *i)*);
iii) *Reservoir filling*. The third phase will be the injection of the captured and transported CO_2 into the reservoir (the operational phase). This stage of the project cycle presents the greatest potential risk of CO_2 leakage as there will be changes in the parameters (e.g. temperature, pressure) within the storage reservoir that could potentially trigger containment failures. Thus monitoring of the CO_2 plume and, for offshore sites: the adjacent benthic sediments and benthic waters, and for onshore sites: groundwater, soil and atmosphere will be needed. The permitting process may need to regulate and standardise these activities in terms of the techniques employed, spatial coverage and frequency of observation for different monitoring techniques;

iv) *Decommissioning*. Upon filling of the reservoir or termination of filling activities for any other reason (e.g. insolvency of the operator, no longer economically viable activity etc), the capping-off and decommissioning of the storage reservoir will follow. The site permit needs to ensure that this will be undertaken with the least possible risk of leakage over the long-term;

v) *Site stewardship*. The stewardship of the site, including monitoring of injection and observation wells, and also the injected CO_2 plume is likely to be an ongoing activity indefinitely following decommissioning. A cut-off point for monitoring may be possible when sufficient assurances that the CO_2 is safely sequestered are achieved (which will require definition). In the interim, issues regarding what ongoing site monitoring will be required, and over what frequency and length of time, and who will be responsible for the surveying activity will need to be considered within the permitting framework.

These issues are outlined below (*Figure 4.3*).

Figure 4.3 Permitting issues across the project cycle for a CO_2 storage site



The regulating of, and permitting requirements for, storage sites will clearly need to be developed so as to reflect the evolution of storage site operations (Figure 4.3), taking into account the nature of the different environmental and human health risks posed by each stage of the project cycle. Consideration of whether a fully integrated permit can be developed, or whether permits need only be developed to address specific gaps in existing permitting regimes for analogous activities is also a key consideration.

Permitting issues for each of these steps are reviewed below.

4.3.3 *Site selection*

Site selection is a critical phase in the development of a CCS chain. Poor site selection will prove costly for a storage site developer, as:

i) the infrastructure developed around the site will become stranded assets if the site is deemed to leak at an *unacceptable rate*. This is based on an assumption that a competent authority will have the power to withdraw a site permit/license, based on some interpretation of an *unacceptable leakage rate*;
ii) there may be significant costs involved with securing a leaking site post CO_2 injection. This is based on the assumption that responsibility for managing *unacceptable* leakage from the site will lie with the site developer under the terms of their site license;

Should a storage site permitting regime evolve that includes these two requirements, then much of the onus will be on storage site developers/ operators to ensure that they select sites which, within reasonable expectation, would not leak over an acceptable period of time. Consequently, it could be envisaged that minimal permitting requirements could be needed for the storage site selection phase of a project.

However, it is more likely that a regulator would need a solid body of information that provides suitable evidence of the integrity of the site prior to permitting the development of a CO_2 injection facility. Furthermore, there are a range of other considerations to be made in addition to site integrity during the site selection phase, including:

⇒ Permits for undertaking surveying activities, such as well drilling and seismic surveying;
⇒ Consideration of environmental and ecological risks presented by any leaking CO_2 in the vicinity of the site
⇒ The risk of exposure to nearby human populations to potentially hazardous levels of leaking CO_2, and;
⇒ Questions over ownership of the land overlying the reservoir, and responsibility and liability issues associated with managing any leakage of CO_2.

These are reviewed below.

4.3.3.1 *Storage site integrity and performance*

The capacity and long-term security for CO_2 sequestration in a geological reservoir is strongly dependent on the specific characteristics of the particular formation into which the CO_2 is to be injected. In order to obtain a permit to inject CO_2 into a particular subsurface reservoir, a regulator will require that a site developer provide information and evidence on site integrity and performance – most likely using reservoir modelling techniques – that take into account the following types of issues:

i) *depth* –CO_2 is preferably stored at a sufficient depth to ensure enough pressure is in the reservoir to maintain CO_2 in the dense phase (in the region of a minimum depth of 800-1000m below the surface). Dense phase storage increases the site's storage potential and promotes dissolution into the existing formation fluids, which will serve to improve retention in the reservoir;
ii) *volume and porosity* – the site developer is likely to be required to demonstrate evidence of sufficient storage capacity in the target formation. Reservoir scenario modeling highlighting expected containment pressures at different injected volumes is likely to be necessary. This is likely to be accompanied by evidence of maximum storage capacity, and the corresponding levels of containment pressures envisaged;
iii) *vertical and lateral sealing* – evidence that the storage reservoir is suitably sealed by a low-porosity caprock that can impede or restrict vertical and even possibly lateral (1) migration of the CO_2 plume, especially at the maximum pressures envisaged at full capacity under *ii)* is critical. Evidence that the basal unit of the cap rock is uniform in nature, and also of sufficient integrity to restrict or impede vertical migration via pathways (i.e. good knowledge about fractures, faults, facies changes or non-secure man made structures such as boreholes and wells in order to understand fluid flow and potential migration pathways) is also necessary. Evidence suggesting that the caprock is also able to withstand increasing pressure in the reservoir as it is filled will also be required. Many existing underground injection regulatory regimes set maximum pressures at which material can be injected to prevent overburden fracturing (e.g. the US UIC Regulations, reviewed in *Section 8.4.1*);
iv) *lateral and vertical permeability (injectivity)* - the formation into which the CO_2 is being injected must be sufficiently permeable to CO_2. Low permeability can cause plugging of the near-injector region, and restrict the effective dispersion of the CO_2 plume throughout the reservoir. Permeability also affects the rate at which CO_2 can be injected. As such, some formations may be unsuitable as low permeability makes them uneconomical to fill at the low injection rate or excessive pressure that may be required. The need for high-pressure injection may also damage the reservoir sealing. A pressure window of between 9 – 34.5 MPa is believed to be the viable range for injection;
v) *thermodynamic characteristics* – information about the thermodynamic properties (temperature and pressure) in the target formation will also need to be collated. This can effect density and phase changes in the injected CO_2, and subsequently its dispersion through the reservoir and impact on both CO_2 trapping and also on permeability;

(1) Although lateral sealing is not such an important consideration in the case of aquifers or coalbeds.

vi) *hydrodynamic characteristics* - it will be important to collate information on the hydrodynamic characteristics of the reservoir. Modelling of the fate of fluids displaced around the reservoir during injection is likely to be necessary. For onshore locations, the presence of a significant risk of displacing brines or other formation fluids into potable water aquifers is likely to render a storage site unsuitable;

vii) *geomechanical factors* – forced injection of CO_2 into porous rock structures could promote fracturing in the rock formation, leading to the creation of potential migration pathways for the injected CO_2. This could be a particularly critical factor when coupled with a reservoir of low permeability;

viii) *geochemical factors* – dissolution of CO_2 into formation water will lead to the formation of carbonic acid. Acid formation could damage cement or steel well bores, and effect mineral precipitation in the reservoir, thus restricting storage security. The presence of a sufficient buffer to maintain pH in the reservoir is a further consideration.

ix) *stability of the geological environment* – evidence of the seismic activity in the region is likely to be required, outlining the level of seepage risk based on historical evidence of the magnitude and frequency of seismic events together with their impacts (as evidenced by the migration to the surface of sub-surface fluids).

x) *economic factors* - The presence of any energy or mineral resources in close proximity to the site may also need to be considered for the effects CO_2 storage could have on their future accessibility;

There are also other specific considerations which must be taken into account for the suitability for EOR and ECBM activities. Issues such as miscibility and viscosity of the oils, reservoir pressure, swellability, folding and faulting and geometry of the coal seams, gas saturation conditions, low water saturation etc. The key assessment criteria for storage site integrity are summarised below (*Table 4.1*).

Table 4.1 Site-specific criteria for long term CO_2 storage

Geological formation	Criteria for site selection
Operational and depleted hydrocarbon reservoirs	• reservoir depth • reservoir volume and porosity • upper and lower sealing of the cap rock • lateral and vertical permeability of the reservoir • reservoir heterogeneity • stability of the geological environment
Deep brine filled formations	• reservoir depth • reservoir volume and porosity • permeability • physical and/or hydrodynamic CO_2 barriers • stability of the geological environment
Unmineable coal seams	• reservoir homogeneity • coal geometry • structure of coal seams • depth • permeability • gas saturated conditions • water saturation • stability of the geological environment • adsorption capacity of the coal

The data required to determine these characteristics will have to be collected via appropriate methods (e.g. seismic data, well logs etc.) and integrated into a reservoir simulation model to provide evidence that the formation is capable of securely storing CO_2 under changing conditions.

The collection of site data will also trigger permitting considerations, because of the use of intrusive techniques and seismic surveys. These are reviewed below:

4.3.3.3 *Surveying activities during site selection*

Data collection during the site evaluation phase is likely to be intensive, and require a number of intrusive well bore cores and drillings and seismic surveys to determine site geology, hydrogeology, geochemistry and geomechanics.

A number of well bores will be needed to measure and evaluate geological characteristics of the proposed storage site, such as:

⇒ water pumping tests,
⇒ stratigraphic and facies maps,
⇒ petrology,
⇒ lithology etc.

These will require access to land above the planned storage site. Observational wells in the vadose zone may also be needed for taking baseline measurements of soil CO_2 content and for groundwater sampling, depending on the depth of the vadose zone.

Consequently, permission will be required by site developers from the appropriate landowners (and tenants for onshore sites) regarding access and the undertaking of drilling operations.

Seismic survey data will be needed to develop 2D and 3D survey profiles of formation and confining seal characteristics, and to gain an understanding of structural contours, faults and folds, traps etc., in the formation. Similarly, access will be required for vibroseis trucks and geophones on land, and permissions to undertake marine surveys for offshore sites.

4.3.3.4 *Storage site CO_2 supply and injectivity*

Consideration is likely to be required by the storage site developer of the planned CO_2 supply rate and volume, and the matching storage site capacity and injectivity (or permeability). Evidence that the selected storage site injectivity matches the anticipated supply rate of CO_2 to the reservoir - without the need to drill excessive injection wells - will be a necessary consideration.

Where multiple injection operations are to be carried out by different storage site operators in the same vicinity or storage reservoir, the issue of storage capacity (defined by volume and porosity) becomes critical. The permitting requirements of each operator should ensure that not only individual operators' CO_2 injections do not exceed containment pressure constraints, but also that combined injections are below the maximum pressure constraints feasible for the reservoir.

4.3.3.5 *Assessing environmental and ecological risks*

A site operator is likely to be required to show that the selected site does not pose undue risks to the surrounding environment either through leakage of CO_2 to the surface and subsurface, and/or contamination by oils or other formation fluids displaced by the injection of CO_2. Formation and subsequent mobilisation of certain toxic chemicals (such as metals) in displaced brines also needs to be considered for their effects on surrounding environments.

In marine environments, CO_2 seepage into seawater would lead to a localised reduction in pH, affecting benthic environments and organisms by altering geochemical and biological reactions. Examples of the effects of changing pH on marine ecosystems include leaching of important biological nutrients and modification of proton gradients across biological membranes. As CO_2 concentrations in benthic environments will be highly dependent on seawater mobility, permitting requirements could entail a description of oceanographic currents and topography in the region above the geological site, or avoidance of sites under ecologically sensitive marine ecosystems.

In terrestrial environments, CO_2 leakage to the near-surface atmosphere will affect biologically active areas. Increased soil concentrations of CO_2 affects root development and water and nutrient uptake from the plant. Natural analogues (*Box 4.1*) show that sudden releases of high levels of CO_2 can result in vegetation death.

Based on these factors, consideration of the proximity of the storage site to endangered or sensitive habitats or species, or important commercial fisheries, commercial fishery nursery areas or important native forests or agricultural areas will be required. The potential threats to these areas or species via the possible leakage of CO_2 may render the project environmentally, economically or culturally unacceptable.

Box 4.1 Releases of CO_2: natural analogues

Threats to ecosystems
Mammouth Mountain, a volcano on the south-western rim of Long Valley Caldera, California, is a natural analogue to the sudden release of high concentrations of CO_2. Since 1980, scientists have monitored geologic unrest in Mammoth Mountain. After a persistent swarm of earthquakes beneath the volcano in 1989, scientists discovered that large volumes of CO_2 gas were seeping from beneath it. The resulting elevated CO_2 concentrations have killed ~0.6 km2 of coniferous forest and early signs of human asphyxia were reported in affected areas.

Source: http://quake.wr.usgs.gov/prepare/factsheets/CO2/

One of the other principal effects of the vertical migration of any leaking CO_2 both and on- and offshore will be its dissolution into overlying groundwater (e.g. potable aquifer water) and benthic bottom waters. This will result in changes in the aquatic chemistry through hydrolysation of CO_2 to form carbonic acid, lowering pH. As pH is one of the main variables in water-mediated chemical reactions, a shift in pH will result in changes in geochemistry and water quality (e.g. mobilization of toxic metals, bicarbonate, sulphate etc).

Another possible problem related to CO_2 injection is displacement of brines into overlying potable aquifers, thus potentially contaminating potable water supplies through increasing salinity. Brine management strategies directing displaced brine to sites where impact is minimized are possible, adopting techniques used in the geothermal power industry.

The regulator is likely to be required to make a decision on the acceptability of the project, based on assessment of the potential risks to the natural environment presented by an injection operation. This may entail the undertaking of some form of risk assessment. It is also likely to be subject to public consultation, via the publication of an environmental impact assessment or environmental statement (EIA; see next *Section*).

4.3.3.6 Assessing human health risks

Assessment of the human health impacts associated with all elements of the CCS chain will be an important consideration during project development. The exposure limits for CO_2 are outlined previously (*Box 1.2*). Problematically, as handling of CO_2 has not been practised on a large scale in many parts of the world to date, many of the permitting regimes designed to manage human health risks from industrial installations do not consider CO_2.

An important requirement for both the storage site and injection facility will be the development of an emergency plan in the event of leakage at an *unacceptable* rate (which must be defined).

Publication of an environmental impact assessment or environmental statement will allow public consultation and scrutiny of the potential impacts. Consequently, public and NGO acceptance of CCS as a safe and legitimate activity will be critical to the storage site permitting process.

Box 4.2 ***Public and NGO perception***

Public awareness of CCS technology is still low and it is as yet unclear whether CO_2 storage will be perceived as a risk. In some places CO_2 storage may face similar difficulties in obtaining planning permission that cogeneration plant, waste incinerators and renewables have faced, due to the "Nimbyism" ("not in my back yard" attitude).

The major environmental NGOs have taken different positions on the technology. Whereas some NGOs have adopted an open dialogue to CCS (e.g. NRDC, FoE) some take a sceptical approach towards the issue (e.g. Greenpeace). Several NGOs not only express concern that the technology will undermine the move towards renewables, but also that carbon storage could be used as a long term strategy for the oil and gas and coal industry to continue its development on a business as usual basis. Many NGOs have also expressed their deep concerns over the long-term reliability of geological storage.

Source: ERM summary

The potential risk of polluting important potable water resources – via migration and seepage of CO_2 – is also an important human health issue to consider.

4.3.3.7 *Storage rights, liability, and responsibility issues*

During the site planning phase, consent for the right to store CO_2 in the subsurface will need be granted to the site developer by the host government [or other land owner (1)] under which's [or who's] territory the storage site will be located. The competent authority granting permission is likely to want to understand the predicted migration patterns and ultimate boundaries for the predicted amount of total injected CO_2 plume over the life span of the site (2) . In order to fulfil this requirement, reservoir simulation modelling will be necessary, as described above. In addition, ongoing monitoring during injection and post site closure will be necessary to confirm predicted plume migration patterns (see below).

The outcomes of reservoir modelling are likely to be used as the basis for site permitting, with the host government or regulator setting out liabilities for responsibilities of the site operator in the event that:

⇒ *predicted* characteristics of the injected CO_2 are not met, and;
⇒ *deviation* from this behaviour generates undue risks either because of site leakage or lateral migration of the CO_2 plume outside of the consented boundaries for which the site license was granted.

(1) Depending on how sub-surface rights are granted in different jurisdictions.
(2) It is important to also note that the competent authority is likely to vary for different types of storage media.

The latter is likely to be relevant where CO_2 migrates beyond sovereign territory either into the subsurface under the open ocean or another sovereign state that has not authorised the injection operation. The former will need careful consideration and forms the focus of a large amount of debate at present. Further thoughts and ideas in this context are outlined in *Section 4.3.5*.

Box 4.3 ***A potential emergency response plan for CO_2 releases from storage or injection***

A key consideration for both a geological storage site and an injection facility will be the provision of an emergency plan, outlining planned responses in the event of large scale or chronic release of CO_2 from the storage reservoir or injection facility and/or observation wells.

As part of the permitting process, the developer should be required to submit a plan outlining details on issues such as:

⇒ *Estimates of behaviour and dispersion characteristics of the leaked CO_2 at different locations around the storage reservoir;*
⇒ *Assessment of the potential impacts of leaked CO_2 on any adjacent populations or environments. This might include evacuation plans for affected populations, and an assessment of the capacity of local emergency services and medical facilities to deal with a large scale leak. Proposals for environmental restoration and rehabilitation may also need to be considered;*
⇒ *Detailed consideration of the techniques that might be employed to prevent the leakage of CO_2 from the reservoir;*
⇒ *A communications and coordination strategy for liaison between local emergency services;*
⇒ *Response plans to manage large scale leaking CO_2. This might include details on: how forced decompression of the reservoir may be undertaken to restrict leakage, perhaps via back extraction of CO_2, and; capping-off procedures for leaking wellheads, or other identified rock faults and fissures that may be leaking.*
⇒ *A detailed management plan outlining the organisational response (roles and responsibilities) in the case of a large scale CO_2 leak.*
⇒ *Response plans to manage chronic or background leakage of CO_2, which does not present any immediate risk to human health or the environment.*
⇒ *A commitment to undertake post leakage monitoring to assess any human health and environmental effects.*

Note: Based on similar principles laid out for sites regulated under the EU Seveso II Directive, see below.

4.3.4 *Injection facility development*

Permission for the siting of an injection facility will be required. In all likelihood, an integrated planning permit for both the injection facility and the storage site is likely to evolve. However, within this permit, consideration of the hazards presented by the operation of an injection facility need careful consideration, including:

⇒ *A risk assessment*- This is likely to require consideration of the potential environmental and human health hazard presented by the presence of a facility receiving and handling – and possibly storing (1) - large volumes of pressurised dense-phase CO_2. Typical considerations might include an environmental impact assessment, a site condition report (for onshore sites), and an assessment of the human health risks posed for a particular

(1) CO_2 storage is likely to be needed so as to act as a buffer against irregularities in flow and variation in injector performance.

site; including topographical and atmospheric assessment (i.e. consideration of dispersion). Analogues from other industry sectors are likely to prove sufficient for CO_2 injection. Adoption of the principles of ALARP [(1)] in the engineering design of the facility should also be demonstrated;

⇒ *An emergency response plan* – see Box 4.3;

⇒ *Best available techniques* - An assessment of the best available technologies for large-scale handling, storage and injection of CO_2;

⇒ *Injection well sealing and lining* - The stringency of current sealing methods for abandoned wells often depends on content of the site (e.g. natural gas, acid gas, etc);

⇒ *The nature of the medium the injection well traverses* – permitting requirements are likely to be far more stringent if the well passes through potable aquifers;

⇒ *Monitoring of reservoir* – in terms of pressure and mechanical integrity of wells. Also monitoring of caprock behaviour.

Analogous regimes are well evolved for regulating a number of industrial sectors including: large industrial installations (including those handling hazardous substances), oil & gas platform developments; oil & gas receptor terminals; gas storage facilities; landfill site developments; breweries; underground injection of waste.

A number of permanent observational monitoring wells may need to be constructed during site development. For onshore facilities, appropriate planning, construction and access permits will also be required for these sites.

4.3.5 Reservoir filling

Upon granting of the appropriate licenses for the storage site and injection well head development, and following development of the facilities, reservoir filling operations will need to be conducted according to the conditions set out in the site license or permit. Key considerations will be related to:

⇒ *safe and efficient operation of the injection facility*. The operating permit for the storage site operator will need to take into consideration plant environmental performance (energy consumption etc.) and occupational health and safety issues for workers (CO_2 monitoring devices etc.);

⇒ *measurement of the amounts of CO_2 being injected.* The permit should ensure that appropriate continuous monitoring devices are applied to the flows of CO_2 around the injection facility;

⇒ *subsurface monitoring of the injected CO_2*. This will be necessary in order to ensure that the behaviour of the sub-surface CO_2 plume corresponds with the predicted behaviour outlined in the site permit. It should also allow for the effective detection of leakage. The frequency of different monitoring techniques will need careful development e.g. well bore monitoring could be carried out monthly, seismic surveying over longer periods;

(1) As low as reasonably practicable

⇒ *monitoring of the adjacent soil, groundwater, air or benthic sediments* - this should allow for early detection of any leakage of CO_2, and an assessment of the subsequent contamination to affected environments, in which location, to what extent and over what spatial scale.

4.3.5.1 *Measurement of CO_2 flows into the reservoir*

During the operation of a storage site it is likely to be important that accurate records on the amounts of CO_2 injected into the reservoir are maintained. In addition, it is likely that a storage site operator would also wish to accurately measure the amount of CO_2 they are taking onto the site at the point of custody transfer (this will be particularly important where financial considerations are concerned). As such, the site permitting regime should make it a regulatory requirement to accurately record data to within a certain accuracy range for both custody transfer and injection. Continuous monitoring devices are likely to be required with very high accuracy tolerances (e.g. at around ± 0.5% or better).

Annual public reporting of the amount injected should also be a regulatory consideration in a site permit. This is important for the following:

⇒ *national inventories* - the amount of CO_2 stored in geological storage reservoirs will need to be reported in national greenhouse gas inventories.

⇒ *mass balance reconciliations* - where a mass balance approach to calculating fugitive losses across a capture and storage network is adopted, all installation operators will need to be able to calculate the mass balance around their operation (as per recent suggestions for monitoring and reporting requirements for CCS under the EU ETS; DTI, 2005). Amounts of CO_2 injected are also likely to be reconciled with quantified estimates of both the amount of CO_2 in the storage reservoir (see below) and the amounts of any CO_2 leaking from the reservoir (1).

⇒ *transparency* - it allows all stakeholders to see how much CO_2 is being injected at a particular storage site.

4.3.5.2 *Monitoring injected CO_2 and reporting emissions*

A storage site operator's permit will inevitably include an obligation to monitor behaviour of the subsurface CO_2 plume during and after injection.

Ideally, application of appropriate surveying techniques should be able to quantify the volume and mass of CO_2 in the storage reservoir. These figures could then be correlated with the metered volume and mass of CO_2 injected into the reservoir to allow for a check on whether any leakage is occurring i.e. mass-balancing. However, quantitative surveying techniques will be a major challenge to achieve.

(1) Although it is accepted that significant errors in mass-balance reconciliations is likely given the accuracy possible with metering devices.

Geophysical reservoir monitoring techniques are suitably advanced, and research on the suitability of a range of monitoring techniques continues on the Sleipner and Weyburn CO_2 injection operations. However, to date a definitive toolbox outlining the range of appropriate approaches has yet to be fully developed.

A few examples of some of the techniques under development include:

⇒ well head and casing pressure;
⇒ timelapse (4D) seismic monitoring;
⇒ cross-well seismic monitoring techniques;
⇒ gravity surveys
⇒ EM (electromagnetic) imaging, and;
⇒ well logging.

Seismic techniques work on the fact that the replacement of reservoir fluids with injected dense phase CO_2 changes the geophysical properties of the reservoir, thus giving a different geophysical signal. By collecting post-injection images and comparing these with baseline survey data or original image, it should be possible to gauge the location and rate of movement of injected fluid. In a large part, the success of seismic surveying will depend on the type of reservoir fluid being replaced, and the local mineralogy and petrology of the rock formations.

Continuous air, soil gas and groundwater CO_2 monitoring devices will be necessary to detect any early signs of CO_2 leakage. These devices are also likely to be necessary in order to build public confidence in storage site safety. Remote sensing techniques that can detect changes in ecosystem health and/or concentrations of CO_2 in the air or soil gas may also be applicable, such as plane or satellite imaging techniques. These techniques are currently employed in areas such as Mammoth Mountain in the United States (see *Box 4.1*).

An important consideration for the site permit will be the frequency at which different measurements should be taken; seismic monitoring may be needed at intervals of 5-10 years or maybe longer, cross-well seismic techniques could be employed once per year or more frequently, aerial or satellite remote sensing could be undertaken monthly, whilst other air and soil gas and groundwater monitoring could be undertaken weekly, monthly or continuously.

The site operator should be obliged to annually report to the host government (or appropriate regulatory agency) quantified estimates of the mass/volume of any leaked CO_2. In the event of leakage, the host government should include them in national emissions inventories (see *Box 4.4*). If the reported rate of CO_2 leakage is considered to be unacceptable (this could perhaps be based on factors such as the consequences of any leakage, the amount leaked as a percentage of total injected, and also whether the leak had been rectified), then an interim permit review could be initiated. Otherwise, the operator could be allowed to continue operations. A formal review of operation could also be mandatory for all site operators by introducing time limits on site operating permits (see next section).

Box 4.4 Compiling National Inventories of CO_2 emissions

Under the United Nations Framework Convention on Climate Change (UNFCCC), all signatory Parties are obliged to report annual inventories of emissions and sinks of greenhouse gases to the UNFCCC Secretariat. Currently, the Revised 1996 Inter Governmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, and the 2000 IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Emissions are the 2 methodological guides published by the UNFCCC to assist Parties in compiling their inventories. These inventory reporting guidelines will be updated in 2006, and will include specific guidance for accounting for long-term storage of CO_2.

For CCS activities, two issues arise. Firstly, under the Common Reporting Format (CRF) approach, Parties are obliged to report emissions according to different categories. However, no category currently exists for geologically stored CO_2. Secondly, any fugitive emissions arising from CCS operations should be included within the inventory. Emissions from pipeline transport could be included under 'Energy' alongside fugitive emissions from energy transportation e.g. natural gas. Leakage of CO_2 from storage sites would present a whole new category within 'Sinks'.

To date, Norway has reported stored CO_2 at the Sleipner site as a memo item. The IPCC Special Report on CO_2 Capture and Storage will outline accounting issues in more detail.

A further consideration is whether storage sites should be subject to some form of formal audit and/or verification of data collection and management systems. This could serve to provide the regulator with further confidence in the quality of data submitted.

4.3.5.3 Maintaining environmental integrity in emissions trading schemes

In order to account for any *potential* future emissions of the stored CO_2 back to the atmosphere, many observers have suggested that any emissions reductions credit given to project or installation operators employing CCS should be subject to some form of discounting. Alternatively, it has also been suggested that default factors could developed and applied that assume a standard rate of leakage. However, these approaches present a number of problems in that:

i) they assume that the storage site *will* leak over a set time frame;
ii) that this time frame, and the flux rate can be established *ex ante* based on detailed understanding of the storage reservoir characteristics and the behaviour of the sub-surface stored CO_2;
iii) potentially the discount factor applied could be so small as to have little relevance when converted back to a tCO_2/yr basis (i.e. less than 1 tonne CO_2 or 1 Assigned Amount Unit or EUA per year);
iv) the point in time at which any leakage might occur may not be relevant to any institutional structures and arrangements that currently exist, and;
v) it is unclear upon which basis appropriate discount rates or default factors could be selected.

Whilst a conservative approach to discounting could be adopted, based on estimates from some type of CO_2 leakage scenario modelling, current constraints in the understanding of specific CO_2 fluxes from potential storage reservoir presents a barrier to setting credible rates. Therefore, for the monitoring and reporting framework methodology for CCS under the EU ETS a methodology whereby CO_2 emissions from storage sites be excluded has been proposed (DTI, 2005). Notwithstanding this observation, there remains a definitive need for a commitment to long term monitoring of CO_2 storage sites, as discussed below.

Where CCS is employed as a greenhouse gas emission mitigation technology under an emissions trading scheme, the regulator may wish to lay down a requirement for the storage site operator to make up any leakage determined to have occurred over the licensing period through the purchase emissions reduction credits (Certified Emissions Reduction units or EUAs) equal to the amount emitted. This would allow the environmental integrity of emissions trading schemes to be maintained.

Furthermore, there are several ways in which a storage site operator could manage this risk. These could include ensuring that the contract they have made with the installation(s) exporting CO_2 to the site requires the installation operator to set-aside a proportion of reduction credits to cover any leakage over the period the operating license is valid for.

4.3.5.4 *Time limiting storage site permits/licenses*

A further permitting consideration will be whether to time limit operating permits. It can be envisaged that a regulator would benefit from time limiting storage site operating licenses so that a formal review process may be initiated at appropriate points in time. In the previous section, annual reporting of emissions form a storage site has been suggested, and that this could be used as a trigger for formal review in cases where unacceptable leakage was occurring. However, it may also be more appropriate to set a fixed limit on operations subject to formal review. Given the periodicity of some of the proposed monitoring techniques (e.g. seismic surveying), then it may be most appropriate that a formal review could occur every 5 or 10 years.

The formal review process might consist of the submission of data and evidence that the storage site is operating satisfactorily in terms of plume characteristics, reservoir pressure, remaining containment volume, effects of displacement, health & safety control, leakage etc. It would also allow the regulatory authorities to assess the quality of information submitted in the annual emissions statements.

The formal review should also provide the opportunity for the consideration of the role of CO_2 storage in national greenhouse gas mitigation strategies. For EU Member States, performance of geological storage sites could also influence the way in which the National Allocation Plan for CO_2 allowances (EU Allowances under the EU ETS) is developed.

4.3.6 *Site decommissioning*

Following filling of the reservoir, withdrawal of a site permit, operator insolvency or cessation of filling operations for other reasons, a formal site decommissioning procedure will be necessary. Documented evidence of the proposed decommissioning plan is likely to be required as part of the sites planning consent (as for the extractive industries or landfill operations).

The primary objective of site decommissioning will be the securing of wellheads and other intrusive observation techniques following site abandonment to a suitable standard that can ensure storage site integrity. Evidence that appropriate procedures for capping off wellheads, adoption of appropriate capping standards (e.g. ISO or CEN) along with estimates of the life span and security offered by the proposed sealing process employed i.e. a risk assessment procedure, should be carried out as good practice.

It will be critical to ensure that abandoned wells do not lead to cross-contamination of the soil and groundwater by vertical or lateral migration of CO_2 following the cessation of operations.

4.3.7 *Site stewardship*

Upon closure and decommissioning, the site operator's permit is likely to include a requirement for the operator to remain responsible for monitoring of the site post-closure up until a point in time where sufficient assurances can be given to the host government or regulatory agency that the site is secure and not liable to leak. This is likely to include prescribed post-closure monitoring activities (which will be broadly similar to those required under operational monitoring).

Precedents for appropriate timing may be available in analogous regimes such as landfill sites, mining and extractive industries.

Box 4.5 Precedents from landfill management post-closure

In the case of landfill site closure, the operator is required to notify the competent authority of any significant adverse environmental effects revealed by the control procedures of the site and follow the decision of the competent authority as to the nature and timing of corrective actions to be taken. Similar requirements might apply to CO_2 storage sites.

Finally, the closed landfill site operator is responsible for the monitoring and analyzing of landfill gas and leachate from the site, as well as the groundwater regime in the vicinity of the site. Similarly, the operator of a closed CO_2 storage site should be responsible for monitoring the CO_2 plume migration, seepage to groundwater, subsurface, surface or sea water, as well as groundwater quality in the vicinity of the site.

This timeframe takes into account the time during which the landfill could present hazards. In the case of a CO_2 geological store, it is reasonable to assume that regulators will wish to consider how much of the CO_2 originally injected into a geological formation could potential leak back to the atmosphere over a certain period of time.

In some parts of the world, regimes for the abandonment of offshore equipment is well-established under regimes such as the 1992 Oslo and Paris Convention for the Protection of the Marine Environment of the North East Atlantic (OSPAR). Under this type of system, a field decommissioning plan is drawn up and agreed prior to abandonment (rather than laying down any prescribed requirements at an earlier stage). This allows the operator to employ best available techniques at the time of decommissioning. Of course, a legal obligation for an operator to take some form of responsibility is required in the first instance.

5 *PERMITTING ANALYSIS – GENERAL CONSIDERATIONS*

A brief overview of the general permitting considerations for each of the regions and countries under study is provided below:

5.1 *ENVIRONMENTAL REGULATORY SYSTEMS WITHIN THE EUROPEAN UNION*

The European Union (EU) includes 25 European Member States, namely: Austria, Belgium, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, The Netherlands, and UK. Whilst the European Union is a political and economic alliance amongst European countries, each Member States maintains their own constitutional and legal systems.

Where harmonization of legal requirements or administrative regulations is necessary, the European Commission develops legislation, which after acceptance by the European Council and the European Parliament, are issued as either:

- ⇒ a Council Directive, which must be transposed into Member State legislation according to the legal principles laid down in the Directive, or;
- ⇒ as a Council Regulation, which is legally binding for all Member States following entry into force at the European level.

This approach is consistent with the principle of *subsidiarity*, under which Member States must enforce the relevant laws into National legislation. Thus, the permitting issues outlined here will be broadly consistent across all Member States within the EU-25, albeit with potentially slight differences in the way each Member State has transposed the relevant Directive.

5.2 *ENVIRONMENTAL REGULATORY SYSTEMS WITHIN THE UNITED KINGDOM*

At present there are no specific regulations that cover CCS activities (1). All the European Directives outlined have been transposed into UK legislation following the appropriate criteria laid out in the Directive. Each devolved administration in the UK (England & Wales, Scotland and Northern Ireland) has enacted specific legislation to cover the requirements of EU Directives. The information provided below has focussed on England & Wales.

The UK has long established site permitting procedures relating to environmental issues and a highly evolved planning system that will impact on CCS. Regulatory systems for the oil and gas industry in the UK are also long established and have some applicability in relation to transportation and storage.

(1) Although the forthcoming UK Carbon Abatement Strategy is likely to address the need for a regulatory regime to be established.

5.3 *Environmental regulatory systems within the United States*

In the US, there are no specific Federal regulations relating to the capture and storage of CO_2. Regulatory agencies are currently in a reactive state rather than a proactive state, responding to projects as they arise, with some ad hoc activities ongoing at the both the Federal and State level.

A number of CCS activities in the US are currently in the planning and/or pilot study phase. Analogous processes/programs include the underground injection of CO_2 for Enhanced Oil Recovery (EOR) and the US Environmental Protection Agency (EPA) *Underground Injection Control* (UIC) Regulations for the storage or disposal of fluids including storage of drinking water and permanent disposal of liquid hazardous wastes. The most heavily regulated aspect is the storage of materials under UIC regulations. UIC programs are administered at the State level, and individual State regulations sometimes differ from Federal regulations, and from each other, although some States adopt the Federal regulations.

5.4 *Environmental regulatory systems within Canada*

Canada is governed as a commonwealth of Provinces and Territories. In general, Canada has a three-tier governmental system consisting of:

- Federal,
- Provinces and Territories, and;
- Municipal/local government.

According to the Canadian Constitution, natural resources and the environment are under Provincial jurisdiction. The Federal government exerts jurisdiction over transborder issues (international and inter-provincial), the Territories, and territorial waters. Therefore, no single jurisdiction has responsibility for all components of the climate regulatory regime in Canada.

5.4.1 *CCS regulation in Canada*

There are currently no specific Federal regulations governing the capture of CO_2 in Canada. However, Natural Resources Canada (1) has implemented the *Canadian CO_2 Capture and Storage Technology Network* (CCCSTN) to promote the development of CCS as one of several zero emissions technologies and coordinate activities undertaken by various groups working on research, development and demonstration of national CCS initiatives.

The Government of Canada, under the leadership of Natural Resources Canada has developed in consultation with industry and Provinces in western Canada a two-year initiative to help develop incentives for CO_2 capture and

(1)*Natural Resources Canada* is the federal department that promotes the sustainable development and use of natural resources by influencing regulatory agencies on issues such as the environment, trade, the economy, Canadian land and science and technology.

storage projects in Canada. This initiative complements Provincial initiatives such as Alberta's *CO_2 Projects Royalty Credit Program*, as the two run in parallel (see *Box 5.1*).

Box 5.1 ***Canadian Incentive schemes for CCS***

The NRCan $15-million incentives program provides financial support to CO_2 capture and storage projects. It encourages oil and gas producers to incur production costs that can stimulate reductions in CO_2 emissions. To be eligible, a firm must operate a project that injects CO_2 from a Canadian source into a geological formation for storage and/or disposal in Canada, and demonstrate reasonable economic need for the project (i.e. a rate of return below the industry standard of 10 to 15 percent). A single recipient can receive a maximum contribution of $5 million over the two-year program period. Eligible expenditures are defined as up to 50 percent of the cost of capital equipment and all other direct expenses required for capturing, compressing, transporting and injecting CO_2.

The Western Canada Sedimentary Basin, which covers large portions of Alberta, Saskatchewan, Manitoba and the Northwest Territories, contains several mature oil fields that may be candidates for anthropogenic CO_2 -based enhanced oil recovery; operations which would be regulated at the Province/Territory level.

Like the Federal regulations, there are also currently no provincial regulations that apply specifically to the capture of CO_2. However, there are a number of Provincial laws, regulations and codes of conduct and best practice that would apply to operations that have similar environmental and safety issues to those associated with CO_2 storage. Subsequent sections of this report provide an analysis in this context, focussing on the provincial laws and regulations applicable in Alberta, British Columbia and Saskatchewan, as these are the Provinces where most of the CCS-related initiatives are presently taking place.

5.5 ENVIRONMENTAL REGULATORY SYSTEMS WITHIN AUSTRALIA

Australia is governed as a commonwealth of states and territories. Within the Commonwealth executive power is vested in the sovereign (through the position of Governor General) and assisted by commonwealth, state and local governments. The three-tier government system consists of;

- Federal Commonwealth Government
- State and Territory Governments
- Local Government

The Commonwealth Government is responsible for matters of national interest and has acquired some powers as surrendered by the states, residual legislative power lies with each individual state.

The Federal Government has relatively limited constitutional powers over energy and environmental policies; these are primarily the responsibility of the state and territory governments. However, the Federal Government does have ownership and responsibility for offshore energy resources, and would have a similar role with offshore storage of CO_2.

The Federal Government has a co-ordinating role in energy and environmental issues that transcend state boundaries, for example the electricity and natural gas networks.

For energy policy the co-ordinating role of the Federal Government is conducted through the Council of Australian Governments (COAG). The COAG, established in 1992, comprises the Federal Prime Minister, state premiers, territory chief ministers and the President of the Local Government Association.

5.5.1 *CCS regulation in Australia*

Of the countries and regions under study, Australia is by far the most advanced in its consideration of the approach to regulating CCS activities. A number of Federal level initiatives are underway to define the broad regulatory framework for CCS operations, in particular, regulatory controls for CO_2 storage site development and operation.

The COAG has published a Consultation Regulation Impact Statement for the *'Draft Guiding Regulatory Framework for Carbon Dioxide Geosequestration' (see Box 8.7)*. This Regulation Impact Statement has been prepared by the Department of Industry, Tourism and Resources with Australia's own specific regulatory needs in mind.

Included in the approach is a review of the existing literature on regulations, a regulatory gap analysis, risk identification and case studies to test the issues. Legislation considered potentially relevant to CCS included the following categories;

- Occupational health and safety;
- Environment;
- Petroleum;
- Petroleum safety;
- Mineral resources;
- Mineral resource development;
- Coal mining health and safety;
- Offshore activities;
- Land leases;
- Land administration;
- Explosive and dangerous goods;
- Pipelines; and
- Planning.

This is reviewed in greater detail in *Section 8.5.* In addition, this report will consider specific pieces of Commonwealth and State level regulation for Victoria and Western Australia that may be applicable to CCS.

6 PERMITTING ANALYSIS FOR CO_2 CAPTURE PLANT

6.1 INTRODUCTION

This section presents some of the key existing regulatory and permitting requirements that could potentially be applicable to any operator considering the installation of a CO_2 capture plant in Europe, Australia and The United States of America (USA).

The issues relevant to permitting presented by CO_2 capture (presented in *Table 2.3*) are considered in the light of installing a capture plant - using one of the technologies outlined in Chapter 3 - at a power generating facility. This research considers the *additional* permitting and regulatory considerations that could potentially arise as a consequence of installing a CO_2 capture plant.

There are three key mechanisms by which the CO_2 capture plant could affect existing permits and consents. These are:

⇒ technical considerations regarding the "whole process" performance following installation of a CO_2 capture plant at an installation;
⇒ technical performance of the actual CO_2 capture equipment, and;
⇒ changes in the emissions characteristics of the whole installation, which could impact on relevant planning and operational consents.

These are reviewed for each region in the following sections:

6.2 CONSIDERATIONS IN A EUROPEAN CONTEXT

6.2.1 *Current Status of CCS in the context of EU permitting legislation*

At present, very few EU Directives or Regulations make specific reference to CO_2 capture plant (1). However, a range of EU legislation involves the *permitting* and *consenting* of certain industrial activities with the specific purpose of safeguarding the environment and human health. Several other pieces of EU legislation serve to harmonise certain activities across the EU (e.g. in the licensing of oil & gas production, although these have been excluded here).

To this end the following European Directives are of potential relevance (*Table 6.1*).

Table 6.1 EU legislation potentially impacting on the permitting of CO_2 capture plant

Official name	Common name	Permitting requirements
Directive 96/61/EC concerning integrated pollution prevention and control.	IPPC Directive	Requires a site level permit outlining emission limits from major industrial installations.
Directive 97/11/EC amending Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment.	Environmental Impact Assessment Directive; EIA Directive	Requires an environmental assessment to be made, and subjected to statutory consultation prior to consenting of any major development or changes to existing developments.
Directive 2001/42/EC on the assessment of effects of certain plans and programmes on the environment.	Strategic Environmental Assessment Directive; SEA Directive	Requires plans and programmes to be subject to an environmental assessment. Not relevant to site level permitting.
Directive 2003/87/EC establishing a scheme for greenhouse gas emissions allowance trading.	Emissions Trading Directive; EU ETS Directive	Large emitters of greenhouse gases subjected to cap and trade scheme of emissions permits (EU Allowances = 1t CO_2)
Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants. .	Large Combustion Plant Directive; LCP Directive	Set licensing conditions for SO_2, NOx and dust from large power plants.
Directive 96/82/EC on the control of major-accident hazards involving dangerous substances.	Seveso II Directive	Requires authorisation to operate from a CA for installations handling large volumes of dangerous substances

(1) EU Decision C(130)2004 outlining guidelines for monitoring and reporting under the EU Emissions Trading Scheme Directive (makes reference to the need to develop a monitoring and reporting protocol for CCS operations undertaken within the context of the EU. Under the IPPC Directive, the Best Available Technique Reference Manual (BREF note) for Large Combustion plant also makes reference to CO_2 capture (see below).

Some of these Directives, principally the EIA and Seveso II Directive will be more widely applicable to all aspects of CCS beyond just CO_2 capture, and their relevance in this context is discussed below and in proceeding sections.

The following sections outline the relevance of EU permitting legislation in the context of CO_2 capture:

6.2.2 The IPPC Directive

The principal objective of the IPPC Directive is:

> *…to achieve integrated prevention and control of pollution arising from the activities listed in Annex I. It lays down measures designed to prevent or, where that is not practicable, to reduce emissions in the air, water and land from the abovementioned activities, including measures concerning waste, in order to achieve a high level of protection of the environment taken as a whole…(Article 1)*

Activities listed in Annex I are summarised below (*Box 6.1*)

Box 6.1 Summary of installations listed in Annex I of the IPPC Directive

1. Installations or parts of installations used for research, development and testing of new products and processes are not covered by this Directive.
2. The threshold values given below generally refer to production capacities or outputs. Where one operator carries out several activities falling under the same subheading in the same installation or on the same site, the capacities of such activities are added together.

1. Energy industries
2. Production and processing of metals;
3. Mineral industry
4. Chemical industry
5. Waste management
6. Other activities (includes pulp & paper production, textiles; slaughterhouses, food processing, abattoirs etc.)

Article 3 of the Directive sets the *general principles governing the basic obligations of the operator* which includes *energy* [being] *used efficiently* under *Article 3(d)*.

Article 9 (3) of the Directive requires the setting of emissions limits values (ELVs) for installations in an installations permit covering a range of pollutants. A number of *indicative* pollutants for which emissions limit levels should be set are listed in Annex II of the Directive (Box 6.2).

Box 6.2 ***Indicative list of pollutants that should be taken into account if they are relevant for setting emissions limit values under IPPC***

AIR

1. Sulphur dioxide and other sulphur compounds
2. Oxides of nitrogen and other nitrogen compounds
3. Carbon monoxide
4. Volatile organic compounds
5. Metals and their compounds
6. Dust
7. Asbestos (suspended particulates, fibres)
8. Chlorine and its compounds
9. Fluorine and its compounds
10. Arsenic and its compounds
11. Cyanides
12. Substances and preparations which have been proved to possess carcinogenic or mutagenic properties or properties which may affect reproduction via the air
13. Polychlorinated dibenzodioxins and polychlorinated dibenzofurans

WATER

1. Organohalogen compounds and substances which may form such compounds in the aquatic environment
2. Organophosphorus compounds
3. Organotin compounds
4. Substances and preparations which have been proved to possess carcinogenic or mutagenic properties or properties which may affect reproduction in or via the aquatic environment
5. Persistent hydrocarbons and persistent and bioaccumulable organic toxic substances
6. Cyanides
7. Metals and their compounds
8. Arsenic and its compounds
9. Biocides and plant health products
10. Materials in suspension
11. Substances which contribute to eutrophication (in particular, nitrates and phosphates)
12. Substances which have an unfavourable influence on the oxygen balance (and can be measured using parameters such as BOD, COD, etc.).

Article 9 (4) then outlines that the setting of ELVs for these substances…:

> *…shall be based on the* ***best available techniques****, without prescribing the use of any technique or specific technology, but taking into account the technical characteristics of the installation concerned, its geographical location and the local environmental conditions. In all circumstances, the conditions of the permit shall contain provisions on the minimisation of long-distance or transboundary pollution and ensure a high level of protection for the environment as a whole.*

Whilst this Article clearly states that a non-prescriptive approach is taken, guidance for CAs on what constitutes Best Available Techniques (BAT) for each of activities outlined in *Annex I* has been/are being developed. The *Best Available Technique Reference Documents* (BREFs) – issued by the European IPPC Bureau (EIPPCB) – must be taken into account when issuing permits for the relevant sectors covered in *Annex I* (alongside a number of "horizontal" BREFs covering cross-sectoral issues such as *energy efficiency*).

Article 9(4) also requires that provisions for long-range or transboundary pollution are taken accounted of. This aspect of the IPPC Directive suggests that a judgement will need to be made regarding the competing interests of climate change mitigation and potentially higher local emissions as a consequence of installing CO_2 capture plant.

Consequently, the IPPC Directive permitting process can create issues for CO_2 capture in several ways:

1. *The principal of Best Available Technique (BAT)*. Qualifying installations covered by the IPPC Directive will need to consider how the installation of a CO_2 capture plant could affect their overall permit conditions. The greatest conflict will arise as a consequence of the energy-penalty presented by the plant, particularly under Article 3 (d). This could distil out certain options for CO_2 capture.

2. *Emissions limit values for certain pollutants listed in Annex III* [(1)]. It is also important to note that CO_2 is not listed as a pollutant in *Annex III* of the Directive. This creates additional complexities in that the capture of CO_2 is unlikely to be considered BAT in the context of compliance with the Directive. Furthermore, where CO_2 capture potentially comes at the expense of other emissions e.g. possible increase in VOC emissions from the use of solvents such as amine or increase in the pollutant load in wastewater, further complexities in the IPPC Directive permitting process arise. Notwithstanding this observation, there is a significant discretion as to the pollutants a Member State CA can consider for a particular installation, based on the overriding priorities of either the EU or the Member State.

   It is also important to note that lower ELVs may be set for installations in cases where stricter local air quality standards are in operation. Based on this principle, and on that of subsidiarity, local regulators could probably argue that CO_2 is a concern in a "local" or national context e.g. to meet national Kyoto commitments, and therefore allow CO_2 capture to be installed at the potential expense of emissions to other environmental media.

3. In addition, a number of IPPC qualifying installations already employ processes for which components and sub-components that are similar to those required by CO_2 capture plants e.g. amine stripping in mineral oil and gas refineries. Consequently, the BAT guidance offered in exiting BREFs needs careful consideration [(2)].

The details of each BREF in the context of CO_2 capture are reviewed below [(3)].

(1) Indeed, under the EU ETS Directive, for qualifying installations covered by both the EU ETS and the IPPC Directive, the IPPC Directive was specifically amended so that ELVs would not be set for CO_2, whilst the energy efficiency clause of Article 3(d) could also be dropped from a sites IPPC permit conditions.
(2) It is important to note that these technologies would not qualify as 'available' at present, and thus leaves some ambiguity as to how a regulator might apply the BAT principle to a capture plant in a large combustion installation such as a power station.
(3) BREF documents are available from http://eippcb.jrc.es/pages/FActivities.htm

6.2.2.1 The Large Combustion Plant BREF

The EIPPCB has produced a BREF note for large combustion plants covered by the IPPC Directive. The 'Draft Reference document on BAT for Large Combustion Plants (November 2004)' provides an indication of BAT for Capture Plants in this sector. Brief consideration is give to CO_2 removal from flue gases as outlined below (Box 6.3):

Box 6.3 Large Combustion Plant BREF (draft March, 2003)

Section 3.9.2 'Removal of carbon dioxide from flue gases' outlines the following:

'*Given current technology, increasing the thermal efficiency of energy-generating processes and techniques is the most important measure in reducing the amount of greenhouse gases emitted per unit of energy produced. Efficiency increases are, however, limited by various factors so that, even with an increased efficiency, significant amounts of CO_2 will still be emitted. To reduce the emissions of CO_2 further, different technical options are currently under development or at a research stage. These technical options for CO_2 capture and disposal are not yet applied to large combustion plants, but they might be available in the future.*'

Under various sections throughout the BREF document the following comment is provided regarding the current status of CO_2 capture plant within the context of BAT:

'*Secondary measures of CO_2 capture and disposal, …., are at a very early stage of development. These techniques might be available in the future, but they cannot yet be considered as BAT.'*

Based on the guidance outlined above (Box 6.3), there is a clear need for further clarity and guidance to be given to CA in Member States prior to issuing any IPPC permit for a combustion plant installing CO_2 capture plant.

Potential developers will need to consult with IPPC regulators at an early stage of planning in order to ensure that CO_2 capture will be acceptable within a specific power plants IPPC permit.

6.2.2.2 Mineral Oil and Gas Refineries BREF

The use of MDEA is noted in the *Mineral Oil and Gas Refinery BREF* document as BAT for the removal of hydrogen sulphide (which is the main contaminant, although the process will also remove CO_2, typically present in a lower concentration). The removal of CO_2 using MDEA is also covered in CO_2 removal in ammonia manufacture (see below).

Box 6.4 Mineral Oil and Gas Refineries BREF (February 2003)

Chapters 4 and 5 of the BREF outlines BAT for amine scrubbing systems in refineries, including recommendations for the optimum solvents, and solvent handling systems:

Chapter 6 of the BREF discusses emerging technologies which are described as:

'.. as a novel technique that has not yet been applied in any industrial sector on a commercial basis ..'

Under this section is the following discussion:

'Removal of CO_2 from Flue Gas Streams'

Wet scrubbing using caustic soda for the removal of SO_2/NO_x will effectively remove CO_2 as a carbonate. It should be noted, however, that to apply wet gas scrubbing for the sole purpose of removal of CO_2 would be largely self-defeating as the scrubbing process itself and the production of the scrubbing agents both require energy. A number of other licensed processes are available which will remove CO_2 from flue gases using a solvent that can be recycled, typically methylethylamine (MEA). After absorbing the CO_2 in a scrubbing system, the solvent is thermally regenerated, releasing the CO_2. This could then be compressed, liquefied and sent to underground disposal. Present indications are that the high energy requirements of this type of scheme will discourage its general use.'

The document also discusses CO_2 storage, which is the focus of Chapter 6 of this report but included here as the discussion related to BAT.

'Disposal of CO_2

Unlike the abatement of other pollutants no feasible technology exists for the removal of carbon dioxide from flue gases. A number of disposal options are, however, under scientific consideration. For technological, ecological and economic reasons, a viable solution is not yet available, but this option is currently being investigated by certain major operators and the International Energy agency (IEA).'

6.2.2.3 *Large Volume Inorganic Chemicals BREF*

The manufacture of ammonia using the steam reforming process requires the production of a H_2 stream, which is reacted with nitrogen in a synthesis reaction to produce NH_3. In order to produce a H_2 stream, the H_2 must be removed from a natural gas stream in a similar way as envisaged for pre-combustion CO_2 removal processes (*Section 2.2.2*), albeit at a much smaller scale than for power plants.

Guidance provided in specific sections of the BREF can help provide an insight into what may currently be considered BAT in pre-combustion capture type technologies.

Box 6.5 ***Large Volume Inorganic Chemical Ammonia, Acids and Fertilisers Industries BREF (Draft March 2004)***

In the BREF note, Section 2.1 describes in detail those technologies considered as BAT in ammonia production, including:

- *steam reforming (section 2.1.2.1; although the BREF applies a "whole plant" concept without considering specific sub-components of the plant).*
- *Specific sub-components of the plant which are considered and of relevance to pre-combustion capture include:*
- *Low-temperature desulphurisation (section 2.1.3.2.10), which outlines concepts for system optimisation using waste heat sources, and;*
- *CO_2 removal system using improved solvents (section 2.1.3.2.11). This suggests alternative uses for waste CO_2 to prevent venting. It also endorses the use of improved solvents such as MDEA which consume less energy than others and other alternatives for specific CO_2 removal systems. The BREF note suggests that energy savings of 30-60 MJ/kmol CO_2 is possible from this type of system optimisation.*
- *CO_2 removal system using solid adsorbents (section 2.1.3.2.12). The BREF suggests that this technique is applicable to new steam reforming plants, suggesting Pressure Swing Adsorption(PSA) as a more effective way to replace CO_2 removal and methanisation, thus simplifying shift conversion from two steps to one step.*

The BAT described for each of these processes would need to be considered in the design of any pre-combustion capture plant.

The guidance provided in the BREF may be interpreted such that the use of an improved solvent, or a solid adsorbent may be considered as BAT for a CO_2 capture plant. However, a judgement regarding energy efficiency would need to be tested for a larger scale pre-combustion capture plant.

6.2.2.4 Glass Manufacture BREF

Some glass melting processes employ systems which are similar to the oxyfuel firing processes proposed for CO_2 capture. However, the specific dynamics of the glass melting process mean that the BAT guidance laid down in the BREF are not directly applicable to the consideration of oxyfuel plants permitting considerations.

6.2.2.5 Energy Efficiency BREF

A draft "horizontal" *Energy Efficiency BREF* document is under preparation, but has not yet been placed in the public domain. This is may contain issues relevant to the installation of a CO_2 capture plant.

6.2.3 EIA Directive

Prior to providing consent for a proposed CCS operation in the EU, appropriate consideration of the full environmental impacts of the scheme will be necessary via an Environmental Impact Assessment (EIA). This is most likely to be dictated by the requirements of the EIA Directive.

The EIA Directive was developed with the objective that:

> *Member States…adopt all measures necessary to ensure that, before consent is given, projects likely to have significant effects on the environment by virtue,*

inter alia, of their nature, size or location are made subject to a requirement for development consent and an assessment with regard to their effects. (Article 1)

Specific details of the legislation are outlined in brief below:

Article 4 (1) and *(2)* of the Directive lays out the details of the types of development for which an EIA must be carried out:

> *1.* [subject to exemptions under Article 2(3)] *projects listed in Annex I shall be made subject to an assessment* (1) *in accordance with Articles 5 to 10.*
>
> *2.* [subject to exemptions under Article 2(3)] *for projects listed in Annex II, the Member States shall determine through:*
> *(a) a case-by-case examination, or*
> *(b) thresholds or criteria set by the Member State*
> *whether the project shall be made* ***subject to an assessment*** *in accordance with Articles 5 to 10.*

Annex I and *II* of the Directive lists the types of projects subject to EIA, as briefly outlined below (*Box 6.6* and *Box 6.7*).

Box 6.6 ***Projects subject to EIA according to Annex I of the Directive (only key criteria that may be applicable to CCS are shown).***

2. - Thermal power stations and other combustion installations with a heat output of 300 megawatts or more

8. (a) Inland waterways and ports for inland-waterway traffic which permit the passage of vessels of over 1 350 tonnes;
(b) Trading ports, piers for loading and unloading connected to land and outside ports (excluding ferry piers) which can take vessels of over 1 350 tonnes.

9. Waste disposal installations for the incineration, chemical treatment as defined in Annex IIA to Directive 75/442/EEC
(1) under heading D9, or landfill of hazardous waste (i.e. waste to which Directive 91/689/EEC applies) [Not applicable to CO_2 at present].

10. Waste disposal installations for the incineration or chemical treatment as defined in Annex IIA to Directive 75/442/EEC
under heading D9 of non-hazardous waste with a capacity exceeding 100 tonnes per day. [Not applicable to CO_2 at present].

14. Extraction of petroleum and natural gas for commercial purposes where the amount extracted exceeds 500 tonnes/day in the case of petroleum and 500 000 m^3/day in the case of gas.

16. Pipelines for the transport of gas, oil or chemicals with a diameter of more than 800 mm and a length of more than 40 km.

21. Installations for storage of petroleum, petrochemical, or chemical products with a capacity of 200 000 tonnes or more.

(1) 'subject to assessment' refers to the undertaking of an EIA.

Box 6.7 ***Projects subject to EIA according to Annex II of the Directive (only key criteria that may be applicable to CCS are shown).***

2. Extractive industry
(d) Deep drillings, in particular: - geothermal drilling, - drilling for the storage of nuclear waste material, - drilling for water supplies, with the exception of drillings for investigating the stability of the soil;

3. Energy industry
(a) Industrial installations for the production of electricity, steam and hot water (projects not included in Annex I); (b) Industrial installations for carrying gas, steam and hot water; transmission of electrical energy by overhead cables (projects not included in Annex I); (c) Surface storage of natural gas; (d) Underground storage of combustible gases;
(e) Surface storage of fossil fuels; (f) Industrial briquetting of coal and lignite; (g) Installations for the processing and storage of radioactive waste (unless included in Annex I); (h) Installations for hydroelectric energy production; (i) Installations for the harnessing of wind power for energy production (wind farms)
.
10. Infrastructure projects
(c) Construction of railways and intermodal transshipment facilities, and of intermodal terminals (projects not included in Annex I);
(i) Oil and gas pipeline installations (projects not included in Annex I);

11. Other projects
(b) Installations for the disposal of waste (projects not included in Annex I);

13. - Any change or extension of projects listed in Annex I or Annex II, already authorized, executed or in the process of being executed, which may have significant adverse effects on the environment*;*
- Projects in Annex I, undertaken exclusively or mainly for the development and testing of new methods or products and not used for more than two years.

Given the diversity of activities subject to EIA under the Directive, there are a number of areas under which a CCS chain could be required to undertake an EIA, ranging from the power station installing CO_2 capture plant (either as a new installation, or as a retrofit under *Annex II(13)*), the transportation process (pipeline or inland waterway), and the potential extension of the EIA Directive to cover storage sites, and even the surveying needed to identify storage sites (see *Section 8* below).

Articles 5 – 10 of the Directive outline the process by which the 'assessment' (the EIA) must be developed, including appropriate public and statutory consultation processes that must be developed by Member States etc.

Article 5 lays out the informational requirements of the EIA. Under *Article 5(b)*, Member States (1):

> *… consider that a developer may reasonably be required to compile this information having regard inter alia to current knowledge and methods of assessment.*

Much project type-specific guidance has been developed over recent years to assist developers in undertaking EIAs, based on the variety of activities

(1) For the purposes of brevity, the full informational requirements under Articles 5 and 6 of the EIA Directive have not been listed. The reader is referred to Directives 97/11/EC and 85/337/EC for further details.

outlined in *Annexes I* and *II*, although unsurprisingly, not yet for CCS. Typically, this might consist of the type of information outlined in *Sections 2-4* of this report.

Under *Article 6* of the Directive, Member States are required to:

> *(1). …take the measures necessary to ensure that the authorities likely to be concerned by the project by reason of their specific environmental responsibilities are given an opportunity to express their opinion on the request for development consent. Member States shall designate the authorities to be consulted for this purpose in general terms or in each case when the request for consent is made. The information gathered pursuant to Article 5 shall be forwarded to these authorities. Detailed arrangements for consultation shall be laid down by the Member States.*
>
> *(2). Member States shall ensure that:*
> *- any request for development consent and any information gathered pursuant to Article 5 are made available to the public,*
> *- the public concerned is given the opportunity to express an opinion before the project is initiated.*

Given that statutory consultees on the EIA (as required under *Article 6(1)*) will have obligations laid down by their role as the Competent Authority (CA) on other EU legislation e.g. the Environment Agency of England and Wales (the EA) has obligations as the CA on the Water Framework Directive (2000/66/EC), National Emissions Ceilings (2001/81/EC), the VOC Solvents Directive (1999/13/EC) and relevant EU waste disposal legislation, then the spectre of a broad raft of other environmental considerations are introduced at the EIA phase.

In the context of CO_2 capture plant, the retrofitting to an existing power station may require subject to assessment under *Article 4 (1)* or *(2)* under the terms of *Annex II (13)* regarding:

> *Any change or extension of projects listed in Annex I or Annex II, already authorized, executed or in the process of being executed, which may have significant adverse effects on the environment;*

Specific considerations might include changes in the exhaust parameters, water discharges, solid waste management issues etc. For example, emissions from a power station with capture plant are likely to be different in composition and physical characteristics to a standard power station. For example, following post combustion capture the exhaust may require heating or an increase in velocity to obtain adequate dispersion characteristics (see *Section 2.2*). The process for undertaking this type of assessment would, however, be the same (air dispersion modelling etc.), which would then be subject to review by consultees, who would be obliged to discharge their duties with respect to other relevant issues e.g. ambient air quality standards.

The emergence of CCS as a climate change mitigation strategy is likely to lead to amendments in applicable legislation, such as the EIA Directive, so that it is incorporated in its own right. Should this be the case, the issues outlined above will need to be considered.

The EIA requirements (at a Member State level) are considered in greater detail under *Section 8.2* of this report, where the permitting requirements for onshore storage facilities are considered in greater depth.

6.2.4 *SEA Directive*

The SEA Directive has the overarching objective to:

… provide for a high level of protection of the environment and to contribute to the integration of environmental considerations into the preparation and adoption of plans and programmes with a view to promoting sustainable development, by ensuring that, in accordance with this Directive, an environmental assessment is carried out of certain plans and programmes which are likely to have significant effects on the environment. (Article 1)

In order to achieve this objective:

….an environmental assessment shall be carried out for all plans and programmes,

- *(a) which are prepared for agriculture, forestry, fisheries, energy, industry, transport, waste management, water management, telecommunications, tourism, town and country planning or land use and which set the framework for future development consent of projects listed in Annexes I and II to Directive 85/337/EEC* [the EIA Directive]*, or*
- *(b) which, in view of the likely effect on sites, have been determined to require an assessment pursuant to Article 6 or 7 of Directive 92/43/EEC* [The Habitats Directive].

The SEA Directive serves to complement the EIA Directive by ensuring that certain policies and programmes are subject to a broader environmental assessment at a strategic level and earlier stage than in the case of the EIA Directive.

At present, the direct impact of the SEA Directive on specific permitting requirements for CCS is secondary, and has not been considered in further depth in this study.

6.2.5 *EU ETS Directive*

The EU ETS Directive sets out the mechanism by which a regional greenhouse gas [(1)] cap and trade scheme within the EU is established. The Directive entered into force on 1st January 2005.

(1) In the first Period of the EU ETS, only CO_2 is covered by the scheme.

Under Article 5 of the Directive, qualifying installations (mainly large point source CO_2 emitters, broadly mirroring those under the IPPC Directive) must apply for a greenhouse gas emissions permit.

Based on the Member State's National Allocation Plan allocation, as required under Article 9, each qualifying installation will be allocated greenhouse gas emissions allowances (EU Allowances; EUAs). These are valid for the first Period of the EU ETS, covering the period 2005-07.

Under *Article 12*, operators of installations must surrender, by 30th April each year, a number of allowances equal to the installations total emissions in the previous year.

Article 14 lays down the monitoring and reporting requirements for installation operators by which they must measure their greenhouse gas emissions. This is the critical element to consider for installations who are considering capturing CO_2 and exporting it for storage as this will detail the exact process that will be acceptable in recording the amount of CO_2 that was *produced* but not *emitted*.

In relation to *Article 14*, the European Commission produced further guidelines for monitoring and reporting of greenhouse gas emissions from installations included under the EU ETS Directive in early 2004. Decision C(2004) 130 Final of 29th January 2004 *establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to the Directive 2003/87/EC of the European Parliament and Council* ('Decision C(2004)130') sets out the methodologies installations should apply when calculating their annual emissions of greenhouse gases.

Decision C(2004)130 does not include any specific guidelines for monitoring and reporting greenhouse gas emissions from CSS. However, under *Section 4.2.2.1.3* of the Decision, the Commission states that:

> *Member States interested in the development of such guidelines are invited to submit their research findings to the Commission in order to promote the timely adoption of such guidelines* (Box 6.8)

Box 6.8 Key components of Decision C(2004)130 relating to CO_2 export and storage

Transfer of emissions is considered under Section 4.2.2.1.2:
CO_2 which is not emitted from the installation but transferred out of the installation as a pure substance, as a component of fuels or directly used as a feedstock in the chemical or paper industry, shall be subtracted from the calculated level of emissions. The respective amount of CO_2 shall be reported as a memo item.

CO_2 that is transferred out of the installation for the following uses may be considered as transferred CO_2:
— pure CO_2 used for the carbonation of beverages,
— pure CO_2 used as dry ice for cooling purposes,
— pure CO_2 used as fire extinguishing agent, refrigerant or as laboratory gas,
— pure CO_2 used for grains disinfestations,
— pure CO_2 used as solvent in the food or chemical industry,
— CO_2 used as feedstock in the chemical and pulp industry (e.g. for urea or carbonates),
— CO_2 which is part of a fuel being exported from that installation.

CO_2 being transferred to an installation as part of a mixed fuel (such as blast furnace gas or coke oven gas) shall be included in the emission factor for that fuel. Thereby, it shall be added to the emissions of the installation where the fuel is combusted and deducted from the installation of origin.

More specific guidance in relation to CO_2 capture and storage is given under Section 4.2.2.1.3:
The Commission is stimulating research into the capture and storage of CO_2. This research will be important for the development and adoption of guidelines on the monitoring and reporting of CO_2 capture and storage, where covered under the Directive, in accordance with the procedure referred to in Article 23(2) of the Directive. Such guidelines will take into account the methodologies developed under the UNFCCC. Member States interested in the development of such guidelines are invited to submit their research findings to the Commission in order to promote the timely adoption of such guidelines.

Before such guidelines are adopted, Member States may submit to the Commission interim guidelines for the monitoring and reporting of the capture and storage of CO_2 where covered under the Directive. Subject to the approval of the Commission, in accordance with the procedures referred to in Article 23(2) of the Directive, the capture and storage of CO_2 may be subtracted from the calculated level of emissions from installations covered under the Directive in accordance with those interim guidelines.

In response to this request, the UK DTI has undertaken research into the monitoring, reporting and verification requirements for CCS under the EU ETS (DTI, 2005). The approach proposed in the DTI research involves the application of direct measurements of CO_2 flows across a CCS chain (capture-transportation-injection), with the subsequent application of a mass balance reconciliation to estimate any fugitive emissions occurring across the chain to the point of injection. Where an installation has exported CO_2 for CCS, the operator would surrender EUAs equal to the amount of fugitive emissions occurring within the calendar year. Such an approach was considered necessary to maintain the environmental integrity of the EU ETS.

As noted previously, the EU ETS Directive provided for specific amendments to the IPPC Directive such that the requirement to 'use energy efficiently' is dropped from an installations IPPC permit, as this would present double-regulation.

At the time of writing, the European Commission is considering how best to manage the issue of CCS within the EU ETS, as well as in the broader context of the EU regulatory framework.

6.2.6 The LCPD

The LCPD commits Member States to specific reductions in emissions of sulphur dioxide, nitrogen oxides and dust from large fossil fuel burning plant (>50MW), mainly power stations.

Article 4 of the Directive requires that all new and existing plant obtain a license containing ELVs for SO_2, NO_x and dust.

Article 9 of the Directive requires that:

> *Waste gases from combustion plants shall be discharged in controlled fashion by means of a stack….The competent authority shall in particular ensure that the stack height is calculated in such a way as to safeguard health and the environment.*

There are likely to be two effects which need to be taken into account within the context of the LCPD:

- ⇒ The removal of CO_2 from the flue gas stream could impact the behaviour of the waste gas plume.
- ⇒ Removal of CO_2 in the exhaust stream (and potentially much lower NO_x emissions in the case of oxy-fuel firing) will increase the specific concentration of SO_2 (and other pollutants) in the exhaust gases.

These issues will need to be taken in consideration in the LCPD license conditions of the combustion installation to which it has been given

6.2.7 Seveso II Directive

The Seveso II Directive is aimed at:

> *…. the prevention of major accidents which involve dangerous substances, and the limitation of their consequences for man and the environment, with a view to ensuring high levels of protection throughout the Community in a consistent and effective manner. (Article 1)*

Currently power stations are not covered by Seveso II requirements. However, an installation employing CO_2 capture technologies could trigger such a requirement due to the presence of large volumes of:

- ⇒ oxygen (oxyfuel plant) or
- ⇒ hydrogen (pre-combustion capture plant), or
- ⇒ amines (post-combustion capture plant).

The Seveso II Directive takes a tiered approach based on the quantity of the particular dangerous substances present, and the subsequent risk this poses to human health and the environment. Depending on the quantity present, qualifying installations are obliged to comply with different Articles of the Directive.

All operators of qualifying installations are obliged to notify the CA in the Member State (under *Article 6*), outlining the type of installation, the dangerous substance present onsite etc. and information on any changes to these conditions.

They are also obliged to draw-up a major accident prevention policy (under *Article 7*).

A broad number of other obligations are laid down by the Directive, for example, Article 8 obliges operators to produce a safety report, Article 11 obliges operators to produce an Emergency Response Plan.

The corresponding qualifying thresholds applying to different Articles of the Directive, as applicable to different relevant substances, are outlined below (*Table 6.2*).

Table 6.2 Thresholds for different Seveso II substances relevant to CCS

Substance or specific risk phrase/category of substance[A]	Articles 6& 7 (tonnes)	Article 6, 7 & 9 (tonnes)
Hydrogen	5 - 50	> 50
Oxygen	200 - 2 000	> 2 000
Very toxic	5 - 20	>20
Toxic	50 – 200	>200
Oxidising	50 – 200	>200
Explosive	10	50
Flammable	5,000	50,000
Highly flammable	50	200
Etc..		

[A] These are indicative guidelines for different substances. A broad range of risk phrase classifications are applicable to different amine-containing compounds. These would need to be checked on a case-by-case basis depending on the specific amine substance in use. Specific risk phrases for different amine substances can be checked at http://www.ecb.jrc.it/ via their CLASSLAB database

6.3 CONSIDERATIONS IN A UK CONTEXT

6.3.1 *Current Status of CCS in the context UK permitting legislation*

Currently no UK legislation includes any specific references to CCS, although all relevant European Directives outlined in *Section 6.2* have been transposed into UK legislation.

It is important to note that the terminology used in transposing these EU Directives has been amended to meet common terminology used in UK legal system e.g. 'Annex' becomes 'Schedule'.

The competent authorities (CA) for EU Directives in the UK are:

- the Environment Agency of England Wales (the EA),
- the Scottish Environmental Protection Agency (SEPA),
- the Northern Ireland Environment and Heritage Service (NIEHS), and
- the Health & Safety Executive (HSE).

Details of the UK enactments of the relevant EU environmental, health and safety legislation are outlined in more detail in Annex I.

6.3.2 *Summary and overview of permitting considerations for CO_2 capture in the EU and UK*

There are a number of strands of EU legislation that can potentially impact on the installation of a CO_2 capture plant on a large combustion installation. These have all been transposed into parallel UK legislation.

Problematically, in terms of site specific permitting, only loose references are made as to how a CO_2 capture plant would affect decisions regarding site permits. Where they do, the technology is not considered as BAT (for example in the Large Combustion Plant BREF). Consequently, it seems likely that determinations will be made on a case-specific basis – taking into account relevant legislation – and this will lead to the evolution of case law by which future determinations can be made with regard to the EIA Directive and the IPPC Directive.

Issues relating to how CCS will be handled under the EU ETS are ongoing and few conclusions can be drawn at present, suffice it to say that at the moment, it is unclear whether an installation operator would be allowed to account for and trade surplus EUAs arising from the export of CO_2 offsite for sub-surface storage.

Other issues associated with CO_2 capture, such as discharges to water and storage of chemicals are already considered under existing legislation, and have not been covered in this report.

Table 6.3 summarise the current status of permitting in relation to CO_2 capture for the UK and EU.

Table 6.3 Summary of permitting issues for CO_2 capture under EU and UK law

CO_2 capture issue	Gap	Partially Covered	Covered
Energy Penalty		In the UK, IPPC H1 Provides a method for considering energy consumption in determining BAT.	
Storage of Amine solutions			Covered under existing permitting and regulations
Safety of Equipment		Scope for further development.	
Wastewater discharges			Covered under existing permitting and regulations.
Change in exhaust parameters		Some similarities with existing flue gas treatments however will need to be developed, especially in relation to EIA and LCP Directives	
Waste from Amine reclamation			Minimisation of waste is considered in Refinery BAT.

6.4 CONSIDERATIONS IN A US CONTEXT

6.4.1 *Overview*

General permitting issues at power plants in the United States which are likely to be triggered by the addition of a CO_2 capture system are outlined in the proceeding section. The key additional permitting issues covered include:

- energy inefficiencies;
- atmospheric discharges;
- chemical storage and hazardous waste generation; and
- health and safety considerations.

6.4.2 *Energy Penalty on Power Plants*

Power plant energy efficiency is largely a matter of good business practice and is not explicitly regulated in the US. Any "penalties" due to poor or substandard performance (efficiency) are passed on to the end user/consumer through rate adjustments. In the competitive US energy market, poor efficiency is rewarded by poor financial performance.

6.4.3 *Discharge Monitoring*

Under the *US Clean Water Act 1977* (CWA) and *Clean Air Act 1970* (CAA), all discharges (waste water effluents and air emissions) must be permitted by the appropriate regulatory authority (State and/or Federal). Discharges of industrial waste products (in the form of liquids, particulates, or vapours) to surface water bodies and to the atmosphere are generally required to undergo some form of treatment and/or monitoring of pollutants, which then has to be reported to the appropriate State authorities and/or the EPA. Individual State and Federal regulating agencies provide general guidelines for specific chemicals (ambient water quality criteria and drinking water criteria), but individual point discharges from an industrial source are bound by specific limits and terms included in the applicable discharge permits. Changes in discharge magnitude and/or composition must also be reported and may lead to re-permitting and additional requirements in order to continue discharging to the environment.

A *SARA Title III* (1), *Form R* (or *Form A*) annual report, as noted in *40 CFR Part 372*, is required for facilities with certain Standard Industrial Classification (SIC) codes and that otherwise use, process or manufacture regulated chemicals. However, CO_2 itself is not a *SARA*-regulated compound.

6.4.3.1 *Wastewater Discharges*

As authorized by the CWA , the *National Pollutant Discharge Elimination System* (NPDES) permit program (*40 CFR 122*) controls water pollution by regulating

(1) *SARA Title III Superfund Amendments and Reauthorisations – Title III* refers to the *Emergency Planning and Community Right to Know Act* (*EPCRA*) which requires reporting on hazardous and toxic chemicals, and creates a right for communities to access data on chemical emissions.

point sources (e.g., discrete conveyances, pipes, man-made ditches) that discharge pollutants into US waters. Industrial, municipal, and other facilities must obtain permits to discharge directly to surface waters. In most cases, the NPDES permit program is administered by authorized states. Any change to the nature and concentration of discharged wastewater requires a re-evaluation of the NPDES permit. In general, most industrial facilities have little difficulty in establishing/obtaining NPDES permits with the appropriate regulatory authorities. In addition, the EPA permitting requirements have become more streamlined in recent years, simplifying the process.

If CCS were implemented at a facility, wastewater discharge characteristics at that facility may be altered, depending on the capture technology implemented. For example, amine solutions and alkaline solutions utilized in post combustion capture may enter discharges, and would need to be permitted accordingly. An appropriate level of monitoring and/or treatment would be specified in the permit(s).

6.4.3.2 Atmospheric Discharges

The CAA established the first specific responsibilities for government and private industry to reduce emissions from vehicles, factories, and other pollution sources. The CAA directs the EPA to establish national standards for ambient air quality and for the EPA and the States to implement, maintain, and enforce these standards through a variety of mechanisms (*40 CFR Parts 50-99*). At the same time, individual state agencies are responsible for regulating air emissions and will, in most cases, establish emission limits for specific chemicals in the applicable emission permits. Under the EPA Title V program, many industrial facilities roll all air permit stipulations into a single permit.

The CAA does not define CO_2 as a regulated air pollutant. However, CCS activities, especially CO_2 capture at the source, may have a beneficial (e.g. co-capture of H_2S and other trace gases) or adverse impact (e.g. reduced capacity to dilute the emission stream) on associated air emissions. In either case, the regulated emissions will change as a result of CCS, and therefore, require permit adjustment(s).

In accordance with the CAA, any owner/operator proposing a "new source" (i.e., proposing to build a new major stationary "source"; or perform major modifications to an existing stationary source) must apply for a *Preconstruction Air Emissions Permit* and submit to certain preconstruction review requirements and mitigation plans. The implementation of CCS at a stationary source of air pollutants, such as a power plant, will likely trigger a review and re-permitting of such facility to account for changes in emission rates of other pollutants.

While the EPA has not and will not likely define CO_2 as an air pollutant in the near future, states have the right to promulgate such regulations if they see fit. Recently, the State of New Jersey proposed to define CO_2 as a pollutant, the first step toward its regulation. New Jersey plus six other states have brought suit against the US EPA requesting regulations of CO_2 emissions from power plants because of the growing threat of global warming. It is likely that some states will regulate CO_2 emissions in the future, albeit distant future.

Depending on the capture technology implemented, the emissions at a given facility may take on a different chemical and physical character. This includes, among other changes, an increase in fuel combustion to supply ancillary power for the CO_2 capture plant. This would likely result in an increase in the concentration of pollutants (combustion by-products and others) within the facility emissions and will thus require updates to a facility's air permit. In addition, if aerosol (particulates) formation increases, air permit updates will be necessary. Finally, depending on the nature of the increase in emissions, the facility may be required to upgrade or install new air pollution control systems.

6.4.4 Chemical Storage and Hazardous Waste Generation

Chemical storage and hazardous waste generation are regulated by the EPA under the *Resource Conservation and Recovery Act 1976* (RCRA). Waste generators are classified as follows:

- *Conditionally exempt small quantity generators (CESQGs)*: generate less than 100 kg of hazardous waste, or less than 1 kg of acutely hazardous waste per month.
- *Small quantity generators (SQGs):* generate between 100 kg and 1,000 kg of hazardous waste per month.
- *Large quantity generators (LQGs):* generate over 1,000 kilograms (kg) of hazardous waste, or over 1 kg of acutely hazardous waste per month.

If the hazardous waste generated at a facility exceeds the threshold of the facility's current status as a result of CO_2 capture processes, the site would have to be reclassified under RCRA. If a facility does not generate hazardous waste under its current operations and will generate hazardous waste once a CO_2 capture system is installed, the facility will be required to establish itself as a generator of hazardous waste and monitor waste disposal under RCRA.

Typically, large power plants in the US are classified as LQGs. However, smaller power plants are occasionally classified as SQGs. Waste from the post-combustion capture processes, such as solvent containing wastewaters, amine sludges and waste condensates arising from reflux condensers would likely increase hazardous waste generation, and therefore may push the threshold from SQG to LQG.

Since hazardous waste transport and disposal is regulated at the State level, any changes in waste generation would require contacting the individual State in which the facility is located. For example, in Texas, the *Texas Commission on Environmental Quality* (TCEQ) administers programs related to hazardous and non-hazardous waste management at industrial facilities under *30 TAC*

Chapter 335. These wastes must be identified on a Notice of Registration submitted to the TCEQ. Any changes in waste generation (nature and quantity) due to the installation of a CO_2 capture plant would require re-certification in accordance with their program specifications.

6.4.5 *Health & Safety Considerations*

The *Occupational Safety and Health Administration* (OSHA) regulates worker safety and health concerns as well as exposure to hazardous and dangerous chemicals. To date, OSHA has not promulgated requirements related to the capture of CO_2 at stationary sources. OSHA would regulate worker exposure to CO_2 produced during industrial processes that are above OSHA Permissible Exposure Limits (PELs). However, OSHA does not issue permits for such work processes. The responsibility lies with the owners and operators of facilities where CO_2 capture would occur to ensure that an appropriate health and safety monitoring and worker protection program is in place.

6.4.6 *Summary and overview of permitting considerations for CO_2 capture in the USA*

There are many possible technical approaches that can be employed to capture CO_2, and these are typically selected based on cost benefit analysis on a project by project basis. In the US, no standard permitting pathway for CO_2 capture currently exists for the major industrial generators and there are no emerging programs on the near term horizon. It is likely that the federal government will take a lead on this issue at some future point and individual states will have the opportunity to accept the federal program or devise their own state-specific permitting approach. .

The EPA does not presently provide regulatory guidance for CO_2 capture, and has only just started looking into developing such guidance.

The key issues for consideration can be summarised as:

⇒ Energy efficiency of the plant following deployment of CO_2 capture may lead to higher energy costs for US plant operators, although no specific permitting impacts would arise as a consequence of energy penalty issues;

⇒ Changes in magnitude or composition of discharges may require re-permitting under the CWA and CAA;

⇒ Chemical storage/disposal would be dealt with and regulated under the existing RCRA;

⇒ Health & Safety monitoring for on site workers is required, as described in the *Occupational Safety and Health Administration (OSHA) standards, 1910.120*.

Table 6.4 provides a summary of the current status of CO_2 capture under US permitting regimes

Table 6.4 Summary of permitting issues for CO_2 capture under US law

CO_2 capture issue	Gap	Partially Covered	Covered
Energy Penalty	No specific permitting considerations apply to power plant efficiency in the US		
Storage of Amine solutions			Covered under existing permitting and regulations
Safety of Equipment			Covered under OSHA Regulations
Wastewater discharges			Covered under CWA regulations
Change in exhaust parameters		Some re-permitting may be necessary under CAA. Handling of CO_2 capture under SARA-Title III considerations may need to be reviewed	
Waste from Amine reclamation		Specific State legislation on hazardous waste handling will need to be taken into account, based on any changes in status.	

6.5 CONSIDERATIONS IN A CANADIAN CONTEXT

6.5.1 *Overview*

The deployment of CO_2 technologies at a power generation facility in Canada are likely to trigger new and additional permitting requirements for the overall facility, specifically related to:

- Wastewater discharges;
- Atmospheric discharges;
- Chemical storage and hazardous waste generation; and
- Health and safety considerations.

The applicable regulations and associated permitting requirements that may be affected by the presence of a CO_2 capture plant at a power generation facility are discussed below.

6.5.2 *Wastewater Discharges*

6.5.2.1 Federal

The discharge of toxic substances to water is regulated under the *Canadian Environmental Protection Act* (CEPA) and the *Canadian Fisheries Act*. Under CEPA, a facility is required to file an annual report of discharges to water and air with the *National Pollutant Release Inventory*. There are no permits required for wastewater discharges, however, under CEPA the Federal government may require that a Pollution Prevention Plan be prepared for the facility.

Article 43 of the *Fisheries Act* states that no substance that may be deleterious to fish may be discharged to a water body that may contain fish. As such, any discharge of wastewater containing amines or other CO_2 capture solvents may be subject to tight regulation under federal laws. Emission limits specific to water effluent are governed by Provincial laws and regulations or permitting processes.

6.5.2.2 Alberta

Under the *Alberta Environmental Protection and Enhancement Act* (AEPEA), Alberta Environment (1) regulates the release of industrial wastewater through the issuance of approvals and codes of practice that limit wastewater releases from industrial activities.

Under the AEPEA, an integrated, single environmental approval may be issued for a facility. These integrated approvals address all environmental aspects, including: air, industrial wastewater, hazardous and solid wastes, groundwater, soils, sanitary sewage/waterworks, and reclamation and decommissioning aspects of facilities in a single approval. For environmental issues where there is no clear regulatory framework yet in place, Codes of

(1) The Provincial environmental protection authority

Practice would likely be used as a regulatory tool. When a Code of Practice is deemed to be providing clear directions for pollution abatement, it is usually enabled through the permitting processes. As such, it is possible that a Code of Practice for CO_2 capture plant could be developed going forward.

6.5.2.3 British Columbia

Under the provincial *BC Environmental Management Act* (EMA), the *Municipal Sewage Regulation B.C. reg. 129/99 O.C. 507/99* has jurisdiction for the discharge of wastewater from industrial sources. A permit is not required for wastewater discharges as long as the discharges comply with the requirements of the provincial regulation. *Schedules 2-5* of the *Municipal Sewage Regulation* provides water quality limits that must be achieved at all times. These limits pertain to parameters that include pH, total phosphorus and orthophosphate (P), ammonia, biochemical demand (BOD_5) and total suspended solids (TSS).

6.5.2.4 Saskatchewan

A permit is required for a sewage works (including industrial liquid waste) under the provincial *Saskatchewan Environmental Management and Protection Act* (EPMA), unless industrial waste is discharged exclusively into sewage works operated by a municipality.

6.5.3 Atmospheric Discharges

6.5.3.1 Federal

The discharge of toxic substances to air is regulated by CEPA. A facility is required to file an annual report of discharges to water and air with the *Canadian National Pollutant Release Inventory* (NPRI). No permit is required for atmospheric discharges under CEPA, although, the federal government may require that a Pollution Prevention Plan be prepared for the facility.

Under the Kyoto Protocol, Canada has a set target to reduce greenhouse gas emissions to six percent below the 1990 levels by the period between 2008 and 2012. The federal government has the responsibility for the development and maintenance of a reliable, accurate and credible National Greenhouse Gas Inventory as part of its obligations under the United Nations Framework Convention on Climate Change (UNFCCC). To fulfill this obligation, Canada must report its national GHG emissions according to the comprehensive guidance provided by the IPCC.

Under the NPRI, the Government of Canada also requires that greenhouse gas emissions be reported for any facilities emitting greater than 100 kilotonnes of CO_2 equivalent emissions.

6.5.3.2 Alberta

Under the AEPEA, Alberta Environment regulates atmospheric emissions to protect the environment and human health. This is mainly achieved through the issuance of Approvals and Codes of Practice that limit atmospheric releases from industrial activities. Under the AEPEA, an integrated, single environmental approval or Code of Practice may be issued for an industrial facility, including requirements for atmospheric discharges.
Alberta has enacted the *Alberta Climate Change and Emissions Act* to support Alberta's action plan for reducing greenhouse gas emissions. The Alberta action plan on climate change calls for Alberta to cut greenhouse gas emissions intensity (emissions per Canadian dollar of economic production) by 50 per cent below 1990 levels by the year 2020. The *Specified Gas Reporting Program* requires that industrial plants emitting 100,000 tonnes or more of greenhouse gases a year will be required to report these emissions to Statistics Canada [1] . The Government of Alberta is also negotiating a data- sharing agreement with *Statistics Canada* regarding the National Greenhouse Gas Inventory.

Specified Gas Reporting Regulation, Alta. Reg. 251/2004 requires that, in any calendar year commencing, a person releases or permits the release of a specified gas into the environment at a facility at or in excess of the level prescribed in the Standard. The person responsible for the facility is required to submit a specified gas report in respect of the release, including:

- The specified gas reporter;
- The facility to which the specified gas report relates;
- The release of specified gases from the facility; and
- Geologically injected CO_2

The information in a specified gas report regarding specified gas release and geologically injected CO_2 must be calculated or determined in the manner and using the methodologies, emission factors, equations and calculations set out in the Standard.

Under the *Alberta Climate Change and Emissions Management Act* the Lieutenant Governor in Council can make regulations respecting emission offsets, credits and sink rights for the purpose of achieving reductions in specified gas emissions consistent with specified gas emission targets. They can also establish or participate in programs and other measures to carry out the purposes of the Act including: programs and measures for the purpose of reducing specified gas emissions, programs and measures related to the removal of specified gases from the atmosphere through the use of sinks, programs and measures related to adaptation to the effects of climate change. As such, CO_2 storage is covered under the act as sink enhancement.

(1) Canada's Federal statistics agency.

A *Climate Change and Emissions Management Fund* has been established administered by the Minister of Finance. The Fund may be used only for purposes related to reducing emissions of specified gases or improving Alberta's ability to adapt to climate change, including the demonstration and use of specified gas capture, use and storage technology and the development of opportunities for removal of specified gases from the atmosphere through sequestration by sinks.

Currently, Alberta is probably the most advanced of all Canadian Provinces in terms of CO_2 regulation, albeit without any direct limit on emissions of CO_2.

6.5.3.3 British Columbia

Under the BC Provincial *Environmental Management Act* (EMA), a permit is required for the discharge of potential air contaminants (stack or fugitive emissions) along with any air contaminants that may form later in the atmosphere.

Under the *BC Petroleum and Natural Gas Act*, owners or operators of equipment or facilities may discharge from the equipment or facility acid gas (including hydrogen sulphide and carbon dioxide) by means of underground injection provided that the discharge is approved by the Minister of Employment and Investment under the scheme's approval process.

6.5.4 Chemical Storage and Hazardous Waste Generation

6.5.4.1 Federal

The handling of any chemical solvents required for CO_2 capture purposes, for example the storage of chemicals and generation of hazardous wastes, would be regulated by the Provincial Government. In order to ship hazardous wastes from a facility, the workers involved would be required to have completed transportation of dangerous goods training in accordance with the Canadian *Federal Transportation of Dangerous Goods Act*.

6.5.4.2 Alberta

The *Alberta Fire Code* governs the storage and precautions necessary for hazardous materials storage, whilst the storage of hazardous substances at a facility also requires approval under the AEPEA. Under the AEPEA, Alberta Environment has the responsibility for regulating the transportation, treatment and disposal of hazardous wastes. The type and quantity of all hazardous waste moved within the Province are tracked through *Alberta's Hazardous Waste Manifest System*. Under the AEPEA, an integrated, single environmental approval or Code of Practice may be issued for an industrial facility, including requirements for chemical storage and hazardous waste generation.

6.5.4.3 *British Columbia*

The *BC Fire Code* governs the storage and precautions necessary for hazardous materials storage, and the *BC Waste Management Act* outlines procedures and practices necessary in reporting and storing hazardous materials.

The *BC Hazardous Waste Regulation* under the BC EMA indicates that a company in British Columbia that produces or stores more than a prescribed quantity of hazardous wastes must register with the Ministry of Water, Land and Air Protection within 30 days. There is an exemption where hazardous waste is produced or accumulated in a quantity of less than 5 kilograms or 5 litres in a 30-day period.

6.5.4.4 *Saskatchewan*

Under the EMPA, the *Hazardous Substances and Dangerous Waste Goods Regulations* address chemical storage and hazardous waste generation. Ministerial approval is required to store hazardous substances or waste dangerous goods at a facility above specified exemption limits.

Also, under the *Oil and Gas Conservation Regulations*, a plan for the disposal of oil-and-gas wastes or non-oil-and-gas wastes into subsurface formations must be accompanied by the written consent of all owners and all fee simple mineral owners, other than the Crown, that in the opinion of the appropriate minister may reasonably be adversely affected by the disposal; and any other information or material that the minister may require upon which to base an approval.

6.5.5 *Health & Safety Considerations*

Health and safety issues associated with operations that are under Federal jurisdiction according to Constitution Laws are governed under Part II of the *Canada Labour Code*, which regulates worker safety and health concerns as well as exposure to hazardous and dangerous chemicals. Currently, there are no requirements under the *Canada Labour Code* specifically related to CO_2 capture processes.

In addition, each Province has its own health and safety regulation, which are listed below.

- Alberta, *Occupational Health and Safety Act*
- British Columbia, *Workers Compensation Act*
- Saskatchewan, *The Workplace Safety and Health Act*

These regulations allow for monitoring of worker exposure to CO_2 and other hazardous chemicals involved in the CO_2 capture process such as specific forms of amines. There is also a requirement that workers shall never be exposed to an environment where O_2 concentrations are outside a specific range. There are requirements for the control of hydrogen in terms of its flammability, but there are no workplace exposure limits for H_2.

Box 6.9 *IOGCC and hazards posed by CCS*

According to the *Interstate Oil and Gas Contact Commission* (IOGCC) report on CCS, no safety incidents have been reported in Canada since the first acid-gas injection operation began in 1990. These acid-gas injection operations represent a commercial-scale analogue to geological storage of CO_2. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e., design, materials, leakage prevention, and safety) can be easily adopted for large-scale operations for CO_2 geological storage, since a CO_2 stream with no H_2S is potentially less corrosive and hazardous.

Under the Saskatchewan *Oil and Gas Conservation Regulations*, no operator shall allow oil-and-gas wastes or non-oil-and-gas wastes to constitute a hazard to public health or safety or to contaminate fresh water or arable land, notwithstanding any compliance or intended or purported compliance with a plan. This clause could potentially create issues for CCS operations within the Province.

6.5.6 *Summary and overview of permitting considerations for CO_2 capture in Canada*

In Canada, there is no specific federal or provincial standard or regulatory pathway that addresses CO_2 capture.

The key issues for consideration can be summarized as:

⇒ There are no specific federal or provincial permitting impacts related to energy efficiency of a power generation plant following addition of a CO_2 capture facility;

⇒ Changes in magnitude or composition of atmospheric or wastewater discharges will require re-evaluation of federal reporting and provincial permitting requirements;

⇒ Chemical storage and hazardous waste disposal will be covered under the applicable existing provincial regulations;

⇒ Health and safety monitoring for on site workers will be covered under the applicable existing provincial regulations.

Table 6.5 *Summary of permitting issues for CO_2 capture under Canadian law*

CO_2 capture issue	Gap	Partially Covered	Covered
Energy Penalty	No specific permitting considerations apply to power plant efficiency in Canada		
Storage of Amine solutions			Covered under existing permitting and regulations

CO_2 capture issue	Gap	Partially Covered	Covered
Safety of Equipment			Covered under Canada Labor Code and relevant Provincial Regulations
Wastewater discharges			Covered under existing permitting regimes
Change in exhaust parameters		Dealt with on a case-by-case basis through relevant Codes of Practice and Pollution Prevention Plans at the Provincial level.	
Waste from Amine reclamation		Dealt with on a case-by-case basis through relevant Codes of Practice and Pollution Prevention Plans at the Provincial level.	

6.6 CONSIDERATIONS IN AN AUSTRALIAN CONTEXT

6.6.1 *Overview*

Australia has the most advanced permitting regimes in regard to CCS. However, much of the focus has fallen on storage site issues, and there has been no specific consideration of permitting issues in respect to CO_2 capture plants. Indeed, the specific pieces of Commonwealth legislation in operation could act as an impediment to deployment of CO_2 capture in Australian power plants. These are reviewed below:

6.6.2 *Commonwealth regulations affecting CO_2 capture plant*

The principal Federal legislation in relation to CO_2 capture and storage in Australia is the *Commonwealth Environment Protection and Biodiversity Conservation Act 1999 (*EPBC Act*).*

This Commonwealth legislation provides a national framework for determining which projects are required to undertake a Federal EIA process. The legislation aims to enhance environment protection through a focus on protecting matters of national environmental significance and on the conservation of Australia's biodiversity.

The Act identifies seven matters of national environmental significance and provides guidance on activities which trigger the EPBC Act.:

- World Heritage properties;
- National Heritage places;
- Ramsar wetlands of international significance;
- Nationally listed threatened species and ecological communities;
- Listed migratory species
- Commonwealth marine areas; and,
- Nuclear actions (including uranium mining).

Developments which potentially trigger the national environmental significance criteria pass through referral, assessment and approval stages.

One particular aspect of note is the proposal for a specific greenhouse gas emissions trigger under the EPBC (*Box 6.11*).

Box 6.10 Proposed EPBC Act Greenhouse 'Trigger'

The Federal Government has commenced a process of applying a Commonwealth greenhouse trigger under the Environmental Protection and Biodiversity Conservation Act 1999.

Under the draft regulation the EPBC Act would be triggered by major new developments likely to result in greenhouse gas emissions of more than 0.5 million tonnes of carbon dioxide equivalent in any 12 month period. This threshold is equivalent to approximately 10% of the average annual increase in Australia's total greenhouse emissions, therefore applying to projects that can properly be regarded as of national environmental significance, such as the building of a new coal-fired power plant. Any project exceeding the trigger threshold would require approval under the Act and be subject to an environmental impact assessment process.

Assessments would address greenhouse issues such as the extent of likely emissions and whether the project design represents 'best practice' from a greenhouse perspective. The EPBC Act assessment and approval process ensures that environmental, economic and social factors are taken into account. Effects on international competitiveness and regional development would therefore be factored into the process. The delivery of any net greenhouse benefits, such as through the adoption of new technology, would also be considered.

The referral process is designed to establish whether an approval is required, and if so through which assessment approach.

The assessment approaches defined in the EPBC act are;

- Assessment on Preliminary Documentation
- Assessment by Public Environmental Report (PER)
- Assessment by Environmental Impact Statement (EIS)
- Assessment by Public Inquiry
- Assessment by Accredited Process

The EPBC Act allows for a bilateral agreement between the Commonwealth and a State or self-governing territory, which either accredits certain environmental impact assessment processes of that State or Territory (an assessment bilateral) or delegates to a State or self-governing Territory the authority to decide whether to approve an action.

Under an assessment bilateral agreement, the Commonwealth Environment Minister remains responsible for deciding whether an action requires assessment and whether to approve an action.

The Commonwealth Government has agreements in place with Tasmania, Northern Territory and Western Australia, and is negotiating assessment bilateral agreements with the other States.

State or Territory assessment processes can be accredited if they meet benchmarks and regulations set out in the EPBC Act, and in regulations under the Act. For example, the Commonwealth Environment Minister must be satisfied that he or she will receive a report that contains enough information about the environmental impacts of a proposed action in order to make an informed decision about whether to approve it. The assessment process must also involve adequate opportunity for public consultation.

If the proposed greenhouse trigger is approved, it is likely that most, if not all, CO_2 capture and storage projects will be 'called in' to be assessed under the EPBC Act.

The EPBC Act is unlikely to have any specific permitting repercussions for deployment of a CO_2 capture plant at a power plant in Australia, but it is also unlcear whether a power plant employing CO_2 capture would actually trigger the requirements, given that emissions would be significantly reduced.

6.6.3 Australian Greenhouse Office - Generator Efficiency Standard

The *Australian Greenhouse Office* (AGO) of the Department for Environment and Heritage is the principal Federal body charged with managing Australia's greenhouse gas emissions. One of their initiatives has been to introduce the *AGO Generator Efficiency Standards* (GES) measure. Specific objectives of the GES measure are to:

⇒ achieve movement towards best practice in the efficiency of fossil-fuelled electricity generation; and
⇒ deliver reductions in the greenhouse gas intensity of energy supply.

Specifics of the measure are outlined below (*Box 6.11*)

Box 6.11 Summary of AGO - Generator Efficiency Standard

The Australian Greenhouse Office co-ordinates domestic climate change policy for the Federal Government. There are a number of policies including the Generator Efficiency Standards (GES).

The GES are based on voluntary agreements between the Federal government and electricity generators, and seek to apply world best practice to new power plant and existing plants over 30 MWe. Generators representing 90% of the Australian electricity market have signed or are close to signing voluntary agreements.

The standards consider climatic conditions, fuel type, plant age and commercial position of the plant in setting the efficiency standards. The best practice efficiency guidelines for new plants are;

- *Natural gas plant 52% (HHV)*
- *Hard coal plant 42% (HHV)*
- *Brown coal plant 31% (HHV)*

Efficiencies standards have not been developed for power plants employing CO_2 capture technology. Considering the energy penalty associated with a capture plant, new efficiency standards would be required to allow consideration of the additional energy required to capture CO_2.

Clearly, the energy penalty associated with the deployment of a CO_2 capture plant could affect the way a power plant qualifies under the GES. This issue will need consideration by Australian regulators going forward.

6.6.4 Victoria Legislation & Regulation

The primary approvals process for major developments in Victoria can be via either:

⇒ An *Environment Effects Statement* (EES) pursuant to the *Environment Effects Act 1978* and *Environment Effects (Amendment) Act 1994*, or
⇒ A Planning Permit (PP) pursuant to the *Planning and Environment Act 1987*.

For an EES, the workshop participants typically form the basis of the *Technical Reference Group* (TRG), which drafts the EES scope guidelines, advises the proponent on the scope of the EES, supporting technical studies, relevant policy and statutory requirements, coordination of the statutory process and the stakeholder consultation program.

A Planning Permit is still required regardless of the need for an EES. However, the planning permit is 'called in' by the Minister for Planning to enable coordination of the approvals process. In effect, the EES forms the supporting information for the permit application, which is exhibited at the same time and the permit is approved when the EES is approved. This is essentially a formality once the EES is approved.

Various other assessments and approvals may also be required during the EES process and/or during construction in accordance with the Victorian *Archaeological and Aboriginal Relics Preservation Act 1972*, *Flora and Fauna Guarantee Act 1988* and *Environment Protection Act 1990* and *Commonwealth Aboriginal* and *Torres Straight Islander Heritage Protection Act 1984*.

In addition, any development that triggers the Commonwealth EPBC Act must be approved via an EES as the *Commonwealth Department of Environment and Heritage* does not formally recognise the Victorian planning permit approval process as sufficiently rigorous.

6.6.4.1 State Environment Protection Policies (SEPP's)

State Environment Protection Policies (SEPPs) are subordinate legislation made under the provisions of the Environment Protection Act 1970. The objective of the SEPPs are to provide detailed requirements and guidance for the application of the Act in Victoria. This is undertaken with an overall aim of safeguarding the environmental values and human activities (beneficial uses) that need protection in the State of Victoria from the effect of waste.

Under the Environment Protection Act 1970, the requirements in environmental regulations, including impact assessments, works approvals and licenses, must be consistent with SEPPs.

6.6.4.2 *State Environment Protection Policies – Air Quality Management*

The *State Environmental Protection Policy (Air Quality Management)* (SEPP (AQM)) implements a government commitment, reflected in the Victorian Greenhouse Strategy, to promote sustainable business practices by requiring greenhouse gas and energy issues to be addressed in the Environmental Protection Act 1970 works approvals and licensing processes.

A *Protocol for Environmental Management* (PEM) on greenhouse gas emissions and energy efficiency in industry has been issued as an incorporated document of the SEPP (AQM). The PEM specifies:

- The necessary steps to be taken by businesses subject to the Environmental Protection Act 1970 work approval and licensing system to comply with SEPP (AQM) principles and provisions relating to energy efficiency and greenhouse gas emissions; and
- How the EPA will assess compliance.

Under the SEPP any major new developments likely to result in energy usage and subsequent greenhouse gas emissions are required to undergo an audit if energy consumption exceeds 500GJ per annum. Any project exceeding the trigger threshold would require the following:

- Examination of energy consumption and sources;
- Determination of total consumption of all fuels;
- Consideration of occupancy site use and environmental conditions and requirements;
- Analysis of energy performance in relation to size of site and activities carried out at the site; and
- Identification and recommendation of measures to implement energy and financial saving opportunities, where applicable.

Assessments would also address greenhouse issues such as the extent of likely emissions and whether the project design represents 'best practice' from a energy and greenhouse perspective.

6.6.5 *Western Australian Legislation and Regulation*

Environmental issues in Western Australian regulation are typically dealt with under the WA *Environmental Protection Act 1968*. The current approvals system in Western Australia comprises a variety of discrete approvals existing under a number of single purpose pieces of legislation. The responsibility for administering these approvals rests with a range of different Commonwealth and State Government agencies and statutory authorities.

One approval may trigger or inform another, however the system is not integrated, and relies on administrative and facilitative mechanisms to achieve better integration and coordination.

In Western Australia the major organisations involved in the planning/development process include:

- Department for Planning and Infrastructure, who consider how a development complies with planning schemes, strategies and regulations and impacts on services such as power and water;

- Department of Environmental Protection, who consider the impacts of developments on the environment;

- Local Governments, who consider a broader range of issues including community concerns, compliance with local regulations and the impact of the development on surrounding landholders.

6.6.6 *Summary and overview of permitting considerations for CO_2 capture in Australia*

Despite a large amount of attention to regulating CCS by Australian authorities, no specific Commonwealth or State legislation is currently in place for regulating CO_2 capture plants. In fact, existing regulations designed to reduce CO_2 emissions from the power sector could act as an impediment to the deployment of CO_2 capture at Australian power plants.

Specific issues to consider include:

⇒ Commonwealth generator efficiency standards could create permitting issues for power plants installing CO_2 capture plant.

⇒ Victorian State legislation requires case specific assessment of power plant permit authorisations. Specific protocols which relate to greenhouse gas emissions are likely to work in favour of permit applications for power plants employing CO_2 capture.

⇒ Western Australia State legislators have already exhibited an accommodating attitude towards the permitting of CO_2 storage sites. Indeed Western Australian State regulators currently head-up the Commonwealth task force that is reviewing Commonwealth policies and principles for CCS. This suggests that the permitting of power plants employing CO_2 capture should be a relatively straightforward process.

Table 6.6 provides a summary of the current status of CO_2 capture under Australian permitting regimes

Table 6.6 ***Summary of permitting issues for CO_2 capture under Australian law***

CO_2 capture issue	Gap	Partially Covered	Covered
Energy Penalty	AGO GES could act as an impediment to deployment of CO_2 capture		

CO_2 capture issue	Gap	Partially Covered	Covered
Storage of Amine solutions			Covered under existing permitting and regulations
Safety of Equipment			Covered under existing regulations
Wastewater discharges			Covered under existing regulations
Change in exhaust parameters		Some re-permitting may be necessary under Commonwealth and State legislation	
Waste from Amine reclamation			No specific issues identified

7 PERMITTING ANALYSIS FOR CO_2 TRANSPORTATION

7.1 INTRODUCTION

This section presents some of the key existing regulatory and permitting requirements that could potentially be applicable to any operator considering the option of transporting CO_2 in a pipeline in Europe, Australia and the USA.

The issues relevant to permitting presented by CO_2 transportation by pipeline have been considered previously (*Section 3*). Pipelines are widely used for the conveyance of hazardous substances including natural gas, oil, sewage and CO_2. Consequently, there are unlikely to be any major permitting restrictions associated with any *additional* issues triggered by CO_2 transport for the purpose of geological storage. Issues that might create a problem include:

⇒ Existing pipeline regulations are unlikely to consider CO_2 in their current definitions, except in some parts of the USA and Canada (Texas, Arizona, Dakota, Saskatchewan etc.)
⇒ The high pressure associated with CO_2 pipelines could trigger new permitting issues.

Nonetheless, there are unlikely to be any deal-breakers associated with permitting for CO_2 pipelines.

The permitting processes for CO_2 pipelines are reviewed for each region in the following sections:

7.2 *CONSIDERATIONS IN A UK CONTEXT*

7.2.1 *Onshore CO_2 Transportation*

Following capture, CO_2 must be transported to the planned point of injection. Due to the limited number of suitable storage sites within the UK it is likely that this transportation will have to take place over fairly large distances. As outlined in preceeding sections, this report assesses the permitting regime for transportation via pipeline only. Other methods of transportation will require different permits which are not covered here. The following section therefore provides a summary of the permitting pathway for design, construction, operation and decommissioning of a CO_2 pipeline. *Figure 6.1* summarises the main process and permits required through the project lifecycle from project conception through to decommissioning.

7.2.2 *Transportation by Pipeline*

7.2.2.1 *Feasibility Assessment*

The first stage of the feasibility study will be to carry out a route corridor investigation. This study will identify several (normally three or four) route corridor options. A desktop study of each route corridor will be carried out which will determine key environmental and social constraints. The results from this desk top assessment will indicate which is the preferred route option based on social and environmental considerations.

7.2.2.2 *Existing UK Gas Transporter EIA Requirements*

Once the feasibility stage has been completed and the preferred route option is finalised then the developer will need to move onto the conceptual design phase. Under *Part 1 Schedule 3* of the *Public Gas Transport Regulations 1999* (PGT Regulations), which came into effect in July 1999, there is a requirement for an Environmental Statement (ES) (1) '*in respect of a pipe-line with a diameter of more than 800 mm and a length of more than 40 km*'. The ES (which is based on an EIA) must be submitted to the Department for Trade and Industry (DTI) if the pipeline is in England or Wales, and the Scottish Executive if the pipeline is in Scotland.

If the pipeline does not meet the criteria above, an EIA may be required under *Part 2* of *Schedule 3* of the PGT Regulations if 'pipe-line works (other than those described in *Part 1* above) in respect of the pipe-line –

> *'…the whole or any part of which, or the whole of any part of any working width for which, will be within a sensitive area (2); or b) which will have a design operating pressure exceeding 7 bar gauge.'*

(1) Schedule 1 of the PGT Regulations 1999 sets out the topics that an ES must contain.
(2)· A sensitive area is defined as: Site of Special Scientific Interest (SSSI); an area to which *Paragraph (u) (ii)* in the table in *Article 10* of the Town and County Planning (General Development Procedure) Order 1995 (f) applies. [Development likely to affect a SSSI or in an area within 2 km of a SSSI (Article 10)]; land to which *Subsection (3)* of *Section 29 (Nature*

The Public Gas Transporter must then either ask the DTI/Scottish Executive for a determination as to whether or not an EIA is required, or give the DTI/Scottish Executive notice that it intends voluntarily to submit an ES/EIA.

An Environmental Social and Health Impact Assessment (ESHIA) will not automatically be required for all projects in respect of which a determination is requested. In all instances, the key factor is whether a project would be likely to have significant environmental effects. The DTI/Scottish Executive will decide this in the light of individual circumstances and the responses from statutory consultees and other bodies consulted.

Where the *Department of Trade and Industry* (DTI)/*Scottish Executive* is asked for a determination, they are obliged to consult the local planning authority before reaching their decision, unless the Public Gas Transporter includes in its request, a copy of a letter from the local planning authority conveying that authority's view on the request.

It will be for the local authority to liaise as necessary with other bodies for the purpose of giving DTI/*Scottish Executive* views as to whether there are likely to be significant environmental, social or health effects.

In order to ascertain the likely outcome of a determination, it is advisable for the *Public Gas Transporter* to approach the statutory consultees prior to formal application to the DTI/Scottish Executive. If the consultees respond positively then replies can be included in the documentation in support of the application.

7.2.2.3 *The Conceptual Design Phase*

Environmental, Social and Health Impact Assessment

It is envisaged that in most instances an ESHIA will be required. The initial phase of the ESHIA will be to carry out a scoping study which will outline significant impacts. This scoping study will be sent to key consultees who will determine if any major impacts have been omitted. Following scoping the full ESHIA will be carried out. This will include a series of detailed studies which will assess the impacts on all aspects of the natural and social environment. Consultation is an integral and ongoing component of the ESHIA process. Generally none of the studies require additional permits however, if a Phase 2 habitat survey is required then English Nature / Scottish National Heritage may need to be consulted, especially if intrusive investigations are required e.g. relocation of bird nesting sites.

Following completion of the ESHIA, the final report will be submitted to the CA (at present the DTI) who will have requested comments from all statutory consultees. The DTI or other CA will have a set timescale during which they

Conservation Orders) of the Wildlife and Countryside Act 1981 applies; National Parks; the Broads; a property appearing on the World Heritage List; SAMs; AONBs; European designated sites; and Natural Heritage Areas.

must reach a decision on the ESHIA. Most pipeline approvals will include a number of planning conditions that the developer must address / adopt prior to construction.

7.2.2.4 *Above Ground Installation (AGI) Planning Approval*

As part of the pipeline an *Above Ground Installation* (AGI) will be required to house monitoring equipment, telecoms etc which are required for operational and maintenance activities. Planning permission for the AGI will be required from the local planning authority which will probably be sought in conjunction with the ESHIA process.

7.2.3 *Construction*

Prior to construction the developer will need to apply for all the relevant permits required during the construction phase of the project. *Table 7.1* provides a summary of the most common permits required during pipeline construction.

The construction of pipelines for the transport of CO_2 for the purpose of CCS could also be allowed under the *Permitted Development Rights* process (summarised in *Box 7.1*). Conferring of Permitted Development Rights to CO_2 pipelines will ultimately be dictated by high-level policy decisions regarding the urgency of CO_2 mitigation, the importance of CCS operations within that, and the competing interests of regions affected by pipeline developments.

Box 7.1 Permitted Development Rights (England, Wales & Scotland)

To facilitate the effective and prompt development of the natural gas network to meet customers' needs, Public Gas Transporters like National Grid Transco are not required to obtain permissions from the local planning authority under the *Town and Country Planning Act 1990/Town and Country Planning (Scotland) Act 1997* for the installation of underground pipelines. Public Gas Transporters, in common with other utilities, have 'permitted development rights' to lay gas pipelines under Part 17 of Schedule 2 of the *Town and Country Planning (General Permitted Development) Order 1995/Town and Country Planning (General Permitted Development) (Scotland) Order 1992*.

Temporary site offices, and construction bases and pipe dumps are not integral elements of the pipeline system. They are subject to the normal development control processes and usually require consent under *The Town and Country Planning Act 1990*. Design and construction of the project will adhere to *Construction (Design and Management) Regulations 1994*.

Figure 7.1 Permitting flow chart for pipeline developments (onshore)

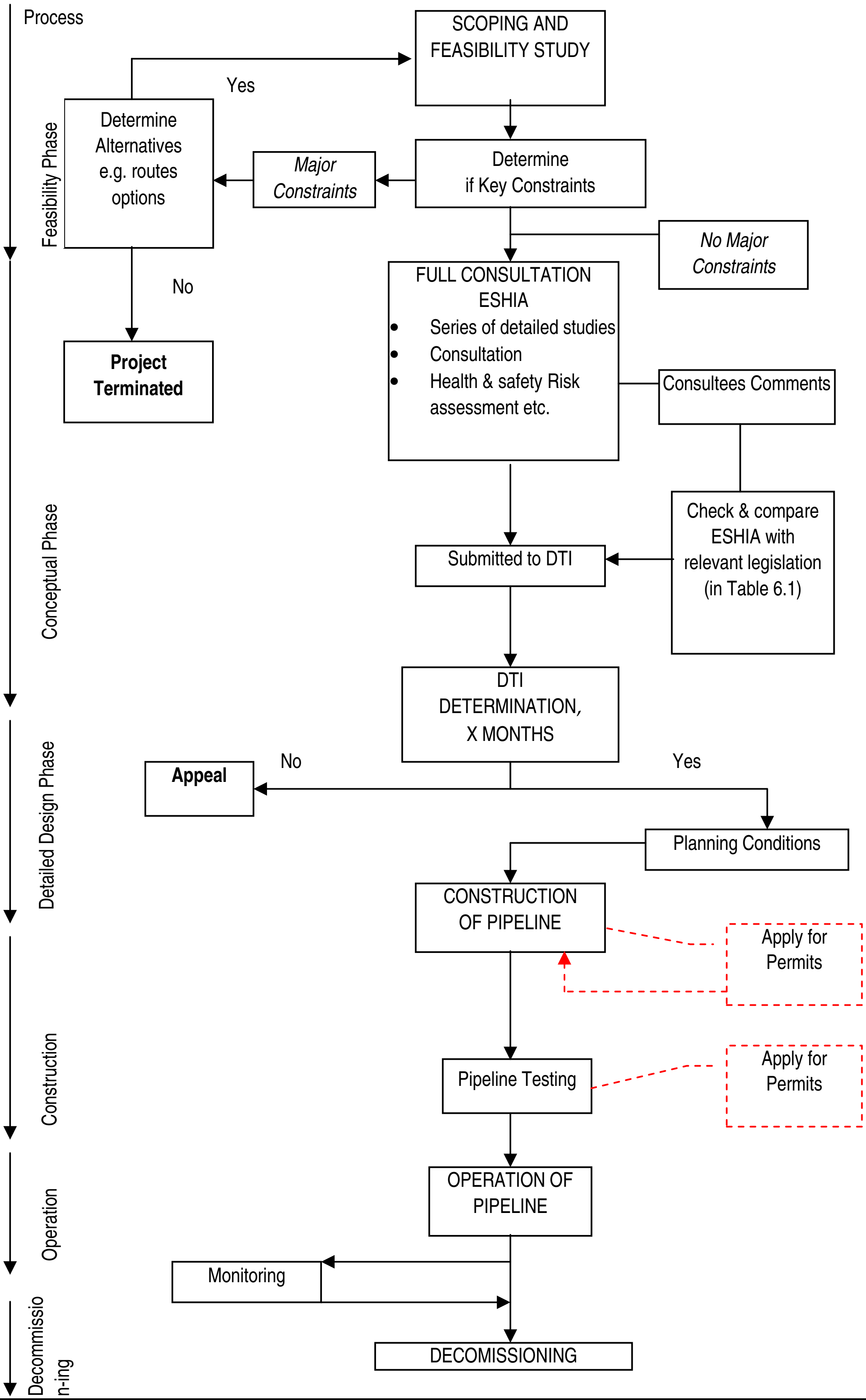


Table 7.1 ***Consents and Authorisations required during the Planning and Construction of Onshore Pipelines (England, Wales & Scotland)***

Notice/Order/ Consent/ Licence	Legislation	Licensing Authority
For Pipeline Construction	*Gas Act 1986* as amended by the *Gas Act 1995, Public Gas Transporter Regulations 1999, Statutory Instrument 1999, No. 1672*	DTI (Secretary of State) (England and Wales) First Minister of the Scottish Executive (Scotland)
Pipeline Safety	*Pipeline Safety Regulations, 1996*	HSE
Pipeline Safety	*Pressure Systems Safety Regulations (2000)*	HSE
Planning Application (Associated Facilities)	*Town & Country Planning Act 1990 (England and Wales)*	Local Authority
	Town & Country Planning (Scotland) Act 1997	Local Authority
Discharge	*Control of Pollution Act 1974*, as amended by the *Environment Act 1995*	The EA SEPA (Scotland)
Abstraction	*Water Resources Act 1991*	The EA SEPA (Scotland)
Main river crossing	*Water Resources Act 1991*	The EA SEPA (Scotland)
Noise	*Environmental Protection Act 1990*, as amended by the *Noise and Statutory Nuisance Act 1993* and the *Environment Act 1995*	Local Authority
Prior consent for control of noise on construction sites	*Control of Pollution Act 1974* as amended	Local Authority
Waste Management License	*Environmental Protection Act 1990* & *Waste Management Regulations 1994*	The EA SEPA (Scotland)
Hazardous substances	*Special Waste Regulations 1996*	The EA SEPA (Scotland)
Litter control areas & litter Abatement notices	*Environmental Protection Act 1990*	Local Authority
Archaeological Sites	*Ancient Monuments and Archaeological Areas Act 1979*	English Heritage Historic Scotland (Scotland)

Notice/Order/ Consent/ Licence	Legislation	Licensing Authority
Footpath closure/diversion	-	Local Authority
Development near a badger sett	*Protection of Badgers Act 1992*	English Nature (England) Countryside Council for Wales (Wales) Scottish Natural Heritage (Scotland)
Disturbance near a badger sett	*Protection of Badgers Act 1992*	English Nature Countryside Council for Wales Scottish Natural Heritage
Hedgerow Removal	*Hedgerow Regulations, 1997 SI 1160*	Planning Authority
Temporary consent for construction site offices and pipe laydown areas	-	Local Authority
Consent for tree felling or disturbing the roots of a tree with a tree preservation order.	-	Local Authority

7.2.4 *Operation*

During operation it is not envisaged that any additional permits will be required for the pipeline. Depending on the type and size of the AGI, an EU ETS permit and allowances could be required; however this will depend on the level of venting, and any changes made to the definition of an installation under the current EU ETS Directive (see *Section 6.2.5*).

Signage and pipeline monitoring requirements may be necessary, and these might parallel the types of techniques used in the CO_2 EOR pipelines in the Permian Basin in West Texas, as described in *Section 7.3.3*.

These requirements would be established in the conceptual design phase.

7.2.5 *Legislative gaps and summary*

Onshore CO_2 transportation is likely to be governed by the same permits and consents those currently applicable to natural gas pipelines in the UK, although the definition of gas in the relevant Acts does not include CO_2. This may require primary legislation to amend the existing definitions of gas.

Additional health and safety considerations are likely to be necessary and included in the ESHIA based on the specific risks posed by high pressure liquefied transport of CO_2.

Whether *Permitted Development Rights* will be conferred to CO_2 pipeline developers is subject to high-level policy decisions regarding the status and urgency of climate change mitigation strategies, relative to the areas affected by pipeline developments.

7.2.6 *Offshore CO_2 Transportation*

7.2.6.1 Introduction

As with onshore transportation this section concentrates on transportation offshore via pipeline only and does not deal with other methods of transport such as marine shipping.

Many similarities can be drawn with onshore pipeline transportation as the ESHIA process will follow the same pathway. However, different legal controls will apply due to nature of regulation of the offshore environment. It should be noted that the process for permitting an offshore pipeline will require two Environmental Assessments to be carried out. One for the offshore component and one for the landfall section of the pipeline. This section therefore summarises the permits required for both components.

7.2.7 *ESHIA Process*

7.2.7.1 Feasibility Assessment Onshore and Offshore

The ESHIA process will be similar to that described in *Section 7.2.1* for the onshore pipeline. The initial phase will require a desk top feasibility study to be undertaken. Again it is likely that several route options will be assessed to determine key constraints. These constraints are likely to include suitable landfall locations, protected fishing grounds, protected environments and shipping lanes etc. No permits are expected to be required at this stage.

7.2.8 *ESHIA Process Offshore*

7.2.8.1 ESHIA Determination

This section provides an outline of the main permits required for the offshore component of the pipeline. This permitting pathway is summarised in *Figure 7.1.* In the UK, permitting requirements for a pipeline system is usually considered in two distinct components:

- **Stage 1** - the preparation of a *Request For Direction* (as required by the *Petroleum Operations Notice* (PON) *PON 15C*), followed by;

- **Stage 2** - the preparation of a full Environmental Statement in support of a formal Application for Consent (*PON 16*).

7.2.9 *Stage 1 – Request for Direction*

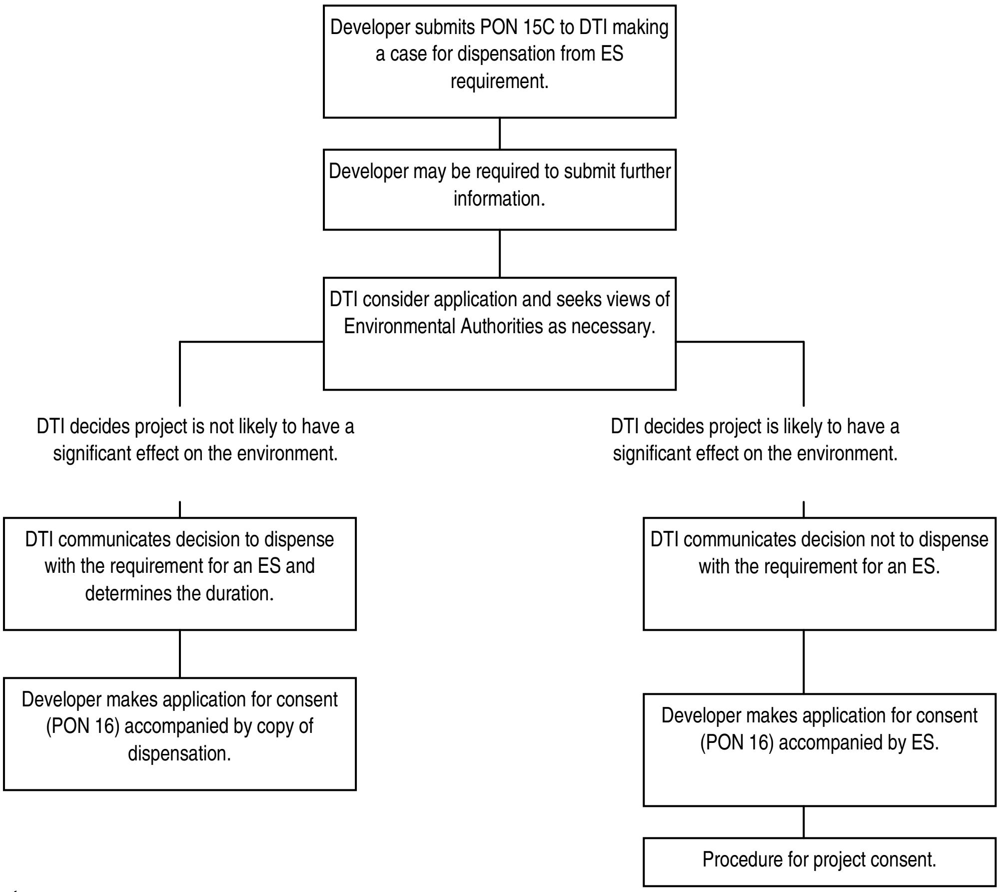
Under the *PON 15C* the developer is required to submit information in order to apply for a request for dispensation from the need to prepare an ES for a proposed pipeline. It should be noted however that for all pipelines over 40km an ES is compulsory. A developer should therefore only submit a *PON 15C* is the pipeline is less than 40km. If a *PON 15C* is to be submitted then the following information should be supplied.

⇒ summary project description including the purpose and planning schedule of the pipeline system;
⇒ alternatives considered;
⇒ basic information on the existing environment conditions in and around the proposed pipeline, in particular any information on sensitive species or habitats;
⇒ outline of EIA process that will be followed if required;
⇒ scope of works that will be covered by EIA process;
⇒ EIA methodology that will be used to assess impacts; and
⇒ objectives of the EIA and subsequent decision making process under UK legislation.

The *PON 15C* must be submitted to the Competent Authority (1). The CA will review the application for direction during which time they will consult with other interested bodies including the Joint Nature Conservancy Council (JNCC), which is a statutory consultee and government advisory organisation. The CA will provide a response within 28 days identifying whether an EIA is required or not. A summary of how this process operates for offshore petroleum pipelines is provided in *Figure 7.2.*

(1) for petroleum pipelines this is the DTI

Figure 7.2 *Stage 1- Dispensation Procedure as required for Offshore Petroleum Pipeline*



Note:

- Where the undertaker wishes to submit an ES with the project Application for Consent the process above is not required.
- The undertaker may submit PON 15C at the same time of application for consent (PON 16). However, should the DTI decide that an ES is required then the project will face delay as the ES is prepared and consultations take place. This may result in refusal or modifications to the project.

Depending on the outcome of Stage 1, as described above, a further Stage 2 may be required. This is essentially the preparation of the EIA and, as a fundamental part of that process, participating in consultation with stakeholders. On completion of the ES the developer is capable of submitting the formal Application of Consent (*PON 16*).

7.2.10 *Stage 2 – Preparation of an Environmental Statement*

Following Stage 1, should it be deemed that a full EIA is required for the pipeline system under UK legislation, scoping will commence.

At present a petroleum pipeline developer is required to carry out an Environmental Assessment (an EIA) under the *Offshore Petroleum Production and Pipelines Regulations (Assessment of Environmental Effects) Regulations 1999* with the DTI acting as the CA. It is possible that CO_2 transportation offshore could fall under the same legislation however the definition of petroleum [1] in the regulations does not specifically cover CO_2.

The initial phase of the EIA process is to carry out a scoping assessment which will involve consultation with the key statutory consultees and the CA. Following receipt of comments on the key constraints of the project the developer will progress to undertaking the full EIA. Upon completion the developer will submit the EIA to the CA along with a pipeline works authorisation (required under the *Petroleum Act 1998*) which includes a consent to locate (required under the *Coast Protection Act 1949*).

7.2.10.1 Key Contacts

During the EIA process a number of key government bodies will be required to consent and approve the installation and operation of an offshore pipeline, landfall and onshore pipeline in UK controlled waters including the list below. Each authority will consult the relevant legislation as outlined in *Table 7.2* to ensure that the EIA meets the requirements of the legislation. *Figure 7.2* indicates the geographical extent of each of the legislative controls identified in *Table 7.2*.

⇒ Department of Trade and Industry (DTI);
⇒ Department for Food Environment and Rural Affairs (DEFRA);
⇒ Marine Consents and Environment Unit (MCEU);
⇒ Department for Transport (DfT);
⇒ Environment Agency (EA);
⇒ Sea Fisheries Committee; and
⇒ Crown Estates (Marine Estates).

Table 7.2 Offshore Legislation Relevant to Proposed Project Development

Relevant Government Body	Legislation	Description / Relevance
DTI	*The Petroleum Act 1988*, Chapter 17	This act requires an authorisation ("Pipeline Works Authorisation") from the DTI for the use or works for the construction of a submarine pipeline. The application process includes a formal consultation process. Authorisation may include conditions for the design, route, construction and subsequent operation of the pipeline.
DTI	*The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999*	This act implements the 1985 and 1997 EC Directives on the "*Assessment of the Effects of Certain public and private projects on the environment*" (The EIA Directive).

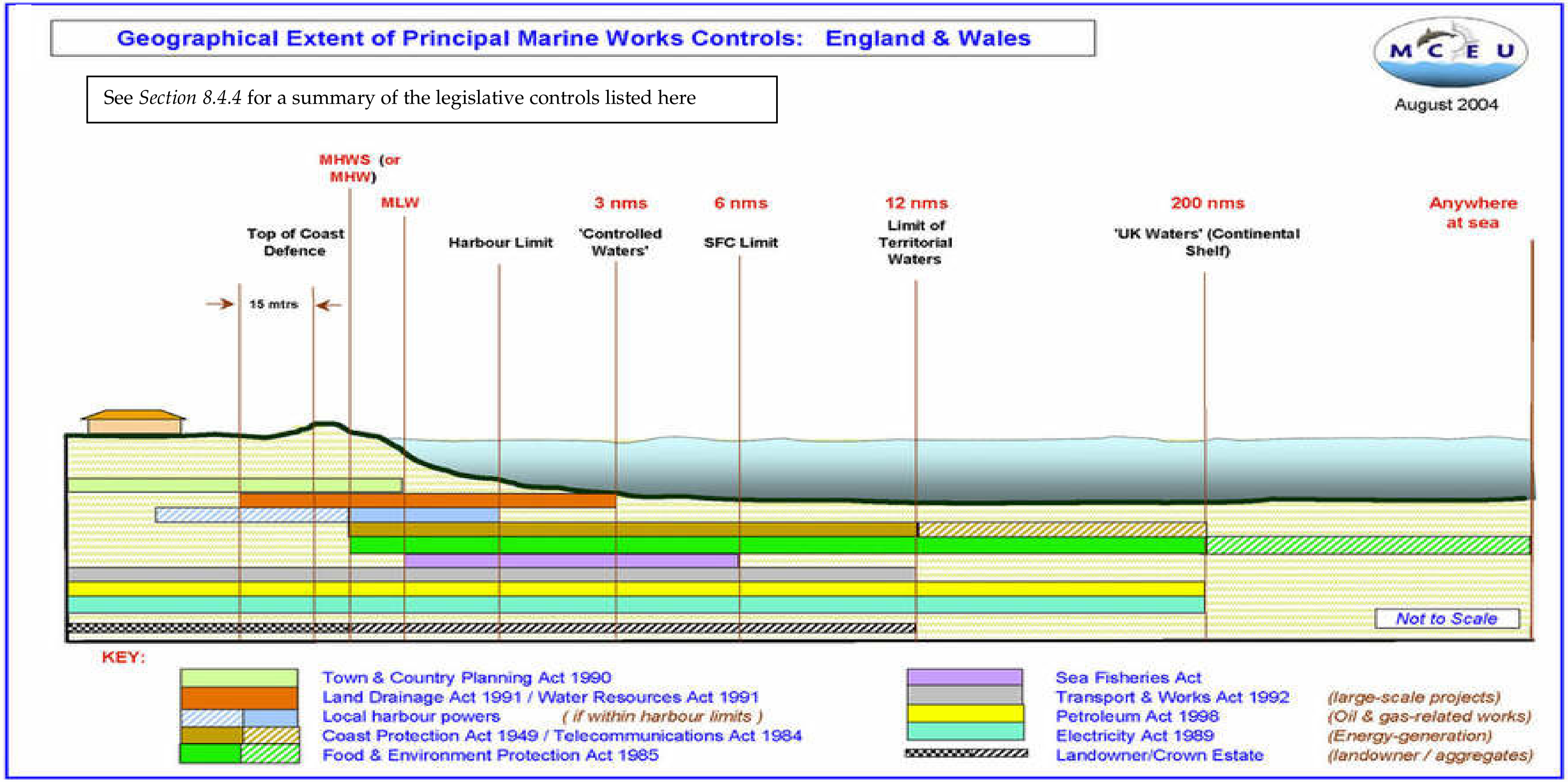
(1) "petroleum" includes any mineral oil or relative hydrocarbon and natural gas existing in its natural condition in strata, but does not include coal or bituminous shales or other stratified deposits from which oil can be extracted by destructive distillation, as defined in the Petroleum Act 1998

Relevant Government Body	Legislation	Description / Relevance
DTI	*The Offshore Petroleum Activities (Conservation of Habitats) Regulations, 2001*	This implements European Directives for the protection of habitats namely, Council Directive 92/43 on the *Conservation of Natural Habitats and of Wild Fauna and Flora and 79/409* on the *Conservation of Wild Birds* in relation to oil and gas activities carried out on the UK Continental Shelf.
Department for Transport (DTI)	*The Coast Protection Act 1949*, Section 34.	Section 34 imposes restrictions on works which may be detrimental to safety of navigation. Consent is required from the Department for Transport which is valid for a period of three years.
DEFRA/ MCEU	*Food and Environment Protection Act 1985* (FEPA)	Generally, a license is required from MCEU where substances or articles are deposited on the seabed. However, the installation of subsea pipelines are exempt from FEPA licensing, provided that the developer has a 'Works Authorisation' from DTI under the Petroleum Act 1998 which covers the deposit in the sea of all material associated with the works.
Sea Fisheries Committee	*Sea Fisheries (Wildlife Conservation) Act 1992.*	Requires ministers to have due consideration to the conservation of marine flora and fauna.

Following confirmation of approval of the EIA, the developer will be required to submit a series of consents which will be required for construction including;

- consent to deposit materials;
- submit application for Chemical Permit *PON 15C*; and
- ensure Waste Management Plan is in place – obtain offshore waste storage and transfer consent.

Figure 7.2 Geographical Extent of Principal Marine Works Controls: England & Wales (from MCEU)



7.2.11 *Onshore EIA Execution*

The onshore component of the development will require approval by the local authority under the *Town and Country Planning Act 1990*, and will require an EIA to be conducted according to the *Town and Country (Environmental Impact Assessment) (England and Wales) Regulations 1999* (1).

The scoping will be conducted in accordance with *EC Guidance on EIA Scoping*. It is possible that in populated areas an ESHIA may be required to ensure that all environmental, social and health issues have been addressed. Following scoping, the ESHIA will be completed addressing the standard set of environmental aspects according to the regulations, with emphasis and focus on any specific issues raised during scoping and consultation. *Figure 7.1* and *Section 7* in this report provide additional information pertaining to permitting onshore pipelines in the UK.

Other consents, which will or may be required for construction of a pipeline landfall, include:

- Planning consent under the *Town and Country Planning Act 1990*
- Agreement of the local landowner (Crown Estate). A license is required from the Crown Estates Commissioners for the laying of a pipeline from the Mean High Water mark out to the UK Territorial Sea Limit (12 nautical miles).
- Consent from the Environment Agency for waste management licenses (*Environment Protection Act 1990*, *Waste Management Licensing Regulations 1994*), and Discharge or Drainage Consents (*Water Resources Act 1991/ Land Drainage Act 1991).*

The ESHIA will be submitted to the CA who will ask for comments from the statutory consultees to ensure that it is compliant with the relevant legislation. The CA will then make a decision based on the information received in the ESHIA and the comments from the consultees. A positive response to construct and operate the pipeline will be accompanied by a series of planning conditions.

7.2.12 *Construction of onshore and offshore components*

Prior to construction it is likely that the developer will be required to complete a bathymetric survey to determine the seabed conditions along the pipeline route. It is likely that the *Centre of the Environment, Fisheries and Aquaculture Science* (CEFAS) will be required to assess the bathymetric survey to ensure that it provides adequate coverage to determine seabed conditions and habitats and will advise on any additional permits required. All other permits relating to waste management, any spoil disposal etc identified in the ESHIA will also be required.

(1) See also DETR Circular 02/99

7.2.13 *Operation*

It is not envisaged that any additional permits will be required during operation however if any permits are necessary they will be identified in the EIA.

7.2.14 *Decommissioning*

Discussions with the CA should take place in good time prior to decommissioning to ensure that the decommissioning programme meets all current standards and requirements. At the time of submitting the programme the developer may need to submit an application for

- *POP71* for any possible oil discharges;
- The disposal of material under *the Food and Environmental Protection Act 1985* (FEPA) if any seabed deposits are anticipated; and
- *PON15E* chemical permit.

The developer will also be required to provide notice of the change of status to the hydrographic office.

7.2.15 *Legislative Gaps and Summary*

Offshore CO_2 transportation will be governed by the same permits and consents as existing offshore oil & gas pipelines in the UK. Additional Health and Safety considerations may need to be included in the ESHIA and it is possible that additional risk assessments may need to be monitored and revised during operation.

Table 7.3 Summary of permitting issues for onshore CO_2 pipeline transport under UK law

CO_2 transport issue	Gap	Partially Covered	Covered
Population density		Covered by existing gas transportation regulations. Similar signage requirements could be adopted from Texan standards.	
Removal of Water	Unclear what the transmission standards will be for CO_2		
Permitted development rights			Covered by existing gas transportation regulations
Definition of a Gas	Legislation will need to be amended before existing law can be applied to CO_2 pipelines		
Hazard / risk			Covered by existing gas transportation regulations

7.3 CONSIDERATIONS IN A US CONTEXT

In the US, it is reasonable to assume that generation of CO_2 may occur in locations relatively distant from deep geologic storage locations, assuming the economics of capture, transport, and disposal have been worked out in a positive way. Inter-state transport may indeed occur and possibly international transport (Canada and Mexico). In fact, among the few pilot programs in North America is an international CO_2 capture, transport and storage program between the US and Canada, where CO_2 is piped from the US midwest (North Dakota) to the Weyburn oil field in Saskatchewan, Canada (*Box 8.5*).

From a regulatory perspective, the US *Federal Energy Regulatory Commission* (FERC) is involved in "energy" projects that involve interstate transport of electricity, gas, fuels, etc. or the transport of gas/fuels in navigable waters of the US. FERC is also involved in the international import/export of electricity, gas, fuels, etc. along transmission lines, gas and other pipelines, etc.

FERC is the regulatory arm of the US Department of Energy (DOE) and sets policy (to some extent), enforces their own regulations, enforces select US *Department of Transport* (DOT) regulations; and incorporates compliance requirements into licenses for many energy projects.

Transportation of CO_2 will, in many cases, fall under an "Energy Project" category, thereby triggering oversight and permitting through FERC, especially where CO_2 is transported across US State lines. Interstate CO_2 transport will likely raise a complex set of questions, as the source and storage locations will, in many instances, require transportation across regulatory regimes (State and international) that will likely have their own permitting requirements. In the case of the Weyburn project, CO_2 transport is between a Kyoto ratifying (Canada) and a non-ratifying country (USA). This presents possible issues for GHG accounting and inventory in respect of Canada's Kyoto Protocol emission reduction commitments, should seepage form the reservoir occur.

The key issues surrounding CO_2 transportation in the US can be summarised as follows:

⇒ CO_2 transportation will most likely take place via pipelines, and would, therefore, be regulated (explicitly) by the DOT under *49 CFR 195 Transportation of Hazardous Liquids by Pipeline*. In this case, the DOT promulgates the regulations, but individual States are obliged to enforce them.

⇒ Right-of-way is required for placement of a new pipeline. Gaining right-of-way is not regulated by a single agency and therefore can require significant effort. This could potentially be mitigated by building CO_2 conveyance systems in existing rights-of-way; (see EIA description under UK Section of this report).

⇒ Alternative transport options, including rail, highway, and marine transport (regulated under DOT guidance *49 CFR 105-180*) tend to be more costly and are, therefore, less likely to be widely used for CO_2 transport.

7.3.1 *Transportation via Pipeline*

While CO_2 is not considered a hazardous liquid, it is treated as such by the DOT (see above) because it is transported in a liquid state. Hazardous liquid pipelines, and hence CO_2 pipelines, are not permitted by a single regulatory agency in the US, and are subject to regulations at the local, state, and federal agencies based on the chosen route of the pipeline.

At the Federal level, CO_2 liquid pipelines fall under the Code of Federal Regulations, *49 CFR 195 Transportation of Hazardous Liquids by Pipeline*. Any new pipeline for the transport of CO_2 would be subject to the following:

⇒ The pipeline must consist of appropriate materials to handle content, loading, temperature, and pressure.
⇒ The pipeline and associated supports must be designed to withstand external loads including earthquakes, vibration, thermal expansion and contraction.
⇒ Associated valves and fittings must also meet internal and external load requirements.
⇒ New and existing pipelines must install a Computation Pipeline Monitoring (CPM) leak detection system.

At the State and local level, the process of permitting CO_2 pipelines requires a search for appropriate Agencies that have permitting authority and can issue a right-of-way or an easement. This requires working with each local and State government affected by the proposed pipeline. For example, if a portion of the pipeline goes through a wetland, permits and approvals will be necessary from:

⇒ local conservation commissions - not present in all States, but a necessary approval process in many;
⇒ State Department(s) of Environmental Protection: likely to be the governing authority in most states;
⇒ *Federal Fish and Wildlife Authority* – may be involved, but does not have direct regulatory authority; generally in a review and advisory capacity;
⇒ the *Army Corp of Engineers* – important permit review and approval process for construction in wetland areas – could be a deal breaker if not consulted and involved early.

Pipeline construction within an existing pipeline right-of-way would avoid much of the regulatory permitting process involved with a new CO_2 pipeline. Operational controls and requirements (e.g. signage, inspection, maintenance) in most cases would mirror those of the associated pipeline(s). For example, in the Permian Basin of Texas where oil and gas exploration and production takes place in the US, an extensive CO_2 pipeline network already exists for use of CO_2 in EOR operations. Consequently, the permitting of any CO_2 pipeline network for the sole purpose of CO_2 storage would not need to consider any new permitting issues.

The *National Historic Preservation Act 1966* was promulgated to ensure the protection of historically significant resources in the United States. Any large-scale construction of a pipeline in the US, or expansion of an existing right of way would require compliance with the letter and intent of this law. For the Weyburn project (*Box 8.5*), this resulted in the completion of archaeological surveys for the pipeline right-of-way. The presence of historically significant resources required re-routing of the pipeline in some areas by as much as 500 feet.

Regardless of the approach, based on the contemporary regulatory framework, permitting for such a pipeline may require between two and four years to achieve completion.

7.3.2 Alternative Transportation

Alternative transport options include rail, highway, and marine transport. These are all regulated under US federal regulations captured in *49 CFR 105-180*. Whilst these options are viable and have been used (the Frio injection project, *Box 8.6*, provides an example of CO_2 received via tanker truck), they are less likely modes of transport, as they are considerably more expensive. The volume of CO_2 that would be captured and transported to an injection point would typically far exceed the volume that could be economically transported by rail or tanker truck. These options are, therefore, only applicable in small scale facilities or pilot projects. Marine transport would only be feasible if the scale of the project and the distance of the capture or injection site from land would render a pipeline cost prohibitively expensive.

7.3.3 Operational Requirements for Transportation Pipelines

Under the *49 CFR 195* requirements for the transportation of hazardous liquids by pipeline (Subpart F - Operation and Maintenance), the following monitoring requirements have been established:

⇒ A manual of written procedures must be established for conducting normal operations and maintenance procedures as well as responding to abnormal operations. This manual must be reviewed and updated once each calendar year.

⇒ The pipeline system must be monitored continuously for
  - pressure,
  - temperature,
  - flow rate, and
  - other appropriate operational data (i.e. CO_2 in the case of liquid CO_2 transport).

⇒ Markers identifying pipeline contents must be placed at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

⇒ The pipeline owner/operator must inspect the surface conditions on or adjacent to each pipeline right-of-way at a minimum of 26 times per calendar year. Methods of inspection can include walking, driving, flying, or other appropriate means of traversing the right-of-way.

⇒ All valves along the pipeline must be inspected twice each calendar year.

⇒ All pressure limiting devices must be inspected twice each calendar year.

⇒ The pipeline owner/operator must ensure the prevention of damage via excavation activities, mainly by participating in a public service program such as a one-call system for excavation activities.

⇒ Additional monitoring requirements may be necessary in high consequence areas such as commercially navigable waterways, high population areas, and other sensitive areas (i.e. wetlands and other environmentally sensitive areas).

7.3.4 *Regulatory gaps in permitting for CO_2 transport in the US*

The following is a brief summary of the key points relative to regulatory gaps for permitting CO_2 transport from source to storage point:

⇒ The permitting process for developing any pipeline system in the United States is not streamlined. Land use and right of way approval for pipelines is not regulated by a single agency, and local, State, and Federal governments do not appear to have a consistent approach.

⇒ Existing rigorous pipeline operational requirements are likely to be sufficient for application to CO_2 pipelines.

Table 7.4 ***Summary of permitting issues for onshore CO_2 pipeline transport under US law***

CO_2 transport issue	Gap	Partially Covered	Covered
Population density Removal of Water Permitted development rights Definition of a Gas Hazard / risk			Covered by existing gas transportation regulations. State level legislation (i.e. Texas) may need to adopted at a Federal level

7.4 CONSIDERATIONS IN A CANADIAN CONTEXT

7.4.1 *Overview*

In Canada it is likely that generation and capture of CO_2 may occur in locations far removed from suitable geologic storage sites, therefore requiring the CO_2 to be transported by some means from the source to the sink.

Transportation across borders, either provincial or national, is also possible. In fact, the current pilot program in the Weyburn oil field in Saskatchewan receives captured CO_2 from pipeline across the US-Canada border from a power plant in North Dakota.

The National Energy Board (NEB) is a federal body responsible for regulating aspects of Canada's energy industry. The NEB aims to protect Canadian public interest by promoting safety, environmental protection and economic efficiency. The NEB's mandate includes regulating pipelines and energy development and trade.

7.4.2 *Transportation via Pipeline*

7.4.2.1 *Federal*

The *Federal Canadian National Energy Board Act* (NEBA), *Part III* regulates the construction and operation of pipelines. This Act has jurisdiction over pipelines that connect Provinces or extend beyond the limits of any Province and transport oil, gas or some other commodity. Certificates from the NEB are required to construct and operate a pipeline. *Pipeline Crossing Regulations* made under the Act do not encompass CO_2 transportation.

Recently, the NEBA was amended to specifically include security. The NEB is proposing changes to the *Onshore Pipeline Regulation*, which currently does not include CO_2 transportation in its definition. However the general trend is towards increased regulations regarding pipeline security, including requiring companies to develop and implement a pipeline security management program.

7.4.2.2 *Alberta*

The *Alberta Pipeline Act* and accompanying *Pipeline Regulation* require a licence to construct and operate a pipeline in the Province. Construction of pipelines must follow certain CSA standards regarding materials and design. Neither the *Alberta Pipeline Act* nor *Pipeline Regulation* specifically mentions the transport of CO_2.

Under the *Pipeline Act, R.S.A. 2000, C. P-15*, a licence for a pipeline may be granted by the Alberta Energy Resources Conservation Board subject to any terms and conditions expressed in the licence or the Board may refuse to grant a licence. The Board may stipulate that the licensee must acquire an interest in any land not owned by the licensee and required for the purposes of the licensee's pipeline by negotiation with the owner.

The Board may make regulations respecting the discontinuation, abandonment and removal of pipelines, including the circumstances under which a pipeline must be discontinued, abandoned or removed, the timing of such discontinuation, abandonment or removal and the manner in which discontinuation, abandonment and removal are to be carried out.

Under the Pipeline Regulation (on order), Alta. Reg. 91/2005 a licensee shall prepare and maintain a manual or manuals containing procedures for pipeline operation, corrosion control, integrity management, maintenance and repair and shall on request file a copy of each manual with the Alberta Energy Resources Conservation Board for review.

The manual shall include provision for evaluation and mitigation of stress corrosion cracking when the licensed pipeline has disbonded or develops non-functional external coatings. It also requires the licensee to prepare and maintain a corporate emergency response plan in accordance with the requirements of the Alberta Energy Resources Conservation Board, and is required to submit a copy to the Board for review on request.

In addition, for a pipeline conveying a product that contains H_2S gas in the gas phase when the pipeline is operating at the licensed conditions, a licensee is required to calculate the emergency planning zone and determine whether any surface development exists or is taking place within the emergency-planning zone. In addition, for pipelines designed to convey gas with a content of more than 10 moles of H_2S gas per kilomole of natural gas, the design stress levels expressed as a percentage of the specified minimum yield strength of the pipe based on nominal wall thickness (SMYS) may not be greater than 60% SMYS for all underground piping, and 50% SMYS for all above ground piping. The pipeline licensee is also required to conduct a pressure test in a manner that will ensure the protection of persons and property in the vicinity of the pipeline. Records or charts of a pressure test must be continuous and legible over the full test period, with the commencement and termination points of the test identified.

7.4.2.3 British Columbia

The *BC Pipeline Act* and *Regulation* maintains that certificates must be obtained from the BC Oil and Gas Commission prior to pipeline construction. Conformance with specified Canadian Standards Association (CSA) standards is required for the design and operation of pipelines.

The *BC Sour Pipeline Regulation* requires that before a sour pipeline is open for service, the company must prepare and implement an emergency response plan that has the approval of the chief inspecting engineer. The emergency response plan must be prepared in conformity with the guidelines as

published by the *Canadian Petroleum Association*, the *Alberta Energy Resources Conservation Board*, or the *BC Oil and Gas Commission*.
The application to construct a sour pipeline must include:

⇒ a chemical analysis of the gas or fluid to be transported,
⇒ a description of the leak detection system,
⇒ the maximum and minimum temperature of the gas or fluid to be transported, and;
⇒ the release volume or release rate, at standard atmospheric conditions, of H_2S from the sour pipeline calculated using the maximum pressure possible.

An emergency planning zone must also be maintained for each sour pipeline, consisting of an area within a parameter formed by using the H_2S release rate in metres per second or volume in cubic metres for the sour pipeline and finding the corresponding distance in kilometres using a graphs set out in the Schedule to the *BC Sour Pipeline Regulation*. The parameter is calculated by measuring the distance out from the outside edges of the sour pipeline.

A sour pipeline must have check and block valves located so that the release of H_2S will remain within acceptable limits in the event of a leak. A sour pipeline must include emergency shut down devices that close on the failure of any control or operating component. Signs must be posted at all sour pipeline facilities warning of the possible presence of H_2S and advising about protective gear requirements.

Before permission to open a sour pipeline for service is granted, evidence that all emergency shutdown devices will fail closed and details of the internal corrosion protection plan for the sour pipeline must be submitted to the *BC* Oil and Gas Commission.

Furthermore, under the *BC Sour Pipeline Regulation*, prior to giving an approval, the chief inspecting engineer may require the company seeking the approval to obtain approval for the emergency response plan for the sour pipeline from any ministry of the government the chief inspecting engineer specifies. The chief inspecting engineer must also be satsified that the emergency response plan for the sour pipeline is sufficiently integrated with plans for emergency response developed or being developed for wells, lines or other land or facilities the chief inspecting engineer specifies.

In BC a sour pipeline means a pipeline containing H_2S in concentrations of 1 mole % or more.

7.4.2.4 *Saskatchewan*

The *Pipelines Act (Saskatchewan)* includes the transport of CO_2 in the definition of a pipeline. *Section 5* of the Act requires a licence to construct, alter, operate or abandon a pipeline. The Regulation also refers to the CSA standard for design and construction. Every pipeline operator is also required to prepare and maintain an emergency procedures manual.

The CSA standard referenced in Provincial legislation is *CSA Standard Z662: Oil and Gas Pipeline Systems*. This Standard covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey CO_2 used in oilfield EOR schemes. The scope of the CSA standard, includes CO_2 pipeline systems, piping and equipment in onshore pipelines, pressure-regulating stations, and measuring stations.

Under the *Pipelines Act*, the Lieutenant Governor in Council may make regulations prescribing the specifications and standards for the construction, alteration, operation and abandonment of pipelines and the discontinuation of the operation of pipelines; prescribing measures for the protection of life, property or the environment to be taken in the construction, alteration, operation and abandonment of pipelines and the discontinuation of the operation of pipelines.

Transported substances must also be measured for the purposes of leak detection and material balance.

7.4.3 Alternative Transportation

Alternative transport options include rail, highway, and marine transport. Although these options are viable, the economic feasibility of transporting CO_2 in this manner would need to be carefully assessed. Typically, the large volumes required to be transported would negate any other benefits. Should CO_2 be transported by means other than a pipeline, it would be considered a dangerous good under the Federal *Transportation of Dangerous Goods Act* (TDG) as well as be subject to the requirements of the *Workplace Hazardous Materials Information System* (WHMIS) for storage and handling in the workplace. TDG requires trained employees to complete manifests upon sending or receiving dangerous goods. In addition transportation vessels must adhere to specific labelling. WHMIS also requires the training of employees to recognize warning symbols on potentially hazardous products. WHMIS labels must include product information.

7.4.4 Regulatory gaps in permitting for CO_2 transport in Canada

The licensing and management of sour gas pipelines in the Canadian Provinces analysed suggest that a robust licensing and permitting regime for pipeline transport of hazardous materials is well evolved. It is conceivable that this regime could be easily conferred onto CO_2 transport. However, it is apparent that some gaps exist in regulations regarding CO_2 transport across different Provinces. The first step to closing this gap would be modifying the definition of pipeline in Provinces such as Alberta to be aligned with those in Saskatchewan.

Table 7.5 Summary of permitting issues for onshore CO_2 pipeline transport under Canadian law

CO_2 transport issue	Gap	Partially Covered	Covered
Population density Removal of Water Permitted development rights Definition of a Gas Hazard / risk			Largely covered by existing acid gas transportation regulations and the need to provide emergency response plans for. Province level legislation (e.g. Saskatchewan, BC) may need to adopted at a Federal level, or at least pushed out to other Provinces in order to provide National coverage

7.5 *CONSIDERATIONS IN AN AUSTRALIAN CONTEXT*

7.5.1 *Onshore CO_2 transportation in Australia*

The relevant pipelines Acts in Victoria and Western Australia do not consider the transport of CO_2. If these Acts were considered the best method to regulate CO_2 pipeline transport, one option would be to amend the definition of 'petroleum' to include carbon dioxide (1).

7.5.1.1 Victoria

Onshore pipeline approvals are issued and administered under the *Pipelines Act 1967* and the *Pipelines Regulations 2000.*

To construct a pipeline two tenements are required;

⇒ Permit to Own and Use a Pipeline
⇒ Licence to Construct and Operate a Pipeline

In addition, before the commencement of construction and operation of a pipeline can begin the following are required;

⇒ *Construction and Environmental Safety Case* (accepted by the *Minerals and Petroleum Regulation Branch*)
⇒ Safety Case for the operation and maintenance of the pipeline for natural gas, accepted by the *Office of Gas Safety*.
⇒ Consent to Operate a Pipeline.

Once a natural gas pipeline has been given consent to operate, the administration of its operation and maintenance is handled by the *Office of Gas Safety* (OGS) under a Memorandum of Understanding between the OGS and the *Department of Primary Industries*.

The Acts address all aspects of pipeline licensing and construction for gas transmission pipelines greater than 1050 kPa, including access to land, safety issues during construction and environmental issues which include licensing, construction and operation issues for non-gas pipelines.

Gas pipelines at less than 1050 kPa (largely distribution pipelines) are exempt from the *Pipelines Act* and are covered by the *Gas Industry Act 1994.*

All gas pipelines are covered by the *Gas Safety Act 1997*, with respect to operational safety.

(1) As applied in the specific case of the Gorgon project, see *Box 8.8*.

7.5.1.2 *Western Australia*

The *Petroleum Pipelines Act 1969* provides for the administration of petroleum pipelines over onshore areas. A petroleum pipeline is defined as a structure that conveys naturally occurring hydrocarbons and is generally in respect to high-pressure pipelines.

The grant of a pipeline licence can only be made following approval that all safety technical and environmental requirements have been met. Pipelines crossing Reserves or Conservation Estates vested in the *Department of Conservation and Land Management* (CALM) require an easement to be approved by CALM. The applicant must apply to the *Australian Environmental Protection Authority* (EPA) for a permit to clear native flora.

Pipeline construction cannot commence until the necessary access rights have been obtained and an application for consent to construct has been approved. When the applicant accepts the conditions, the licence can be granted.

7.5.2 *Offshore CO_2 Transportation in Australia-*

There is an agreement between the Commonwealth and all the States and the Northern Territory to maintain, as far as practicable, common principles, rules and practices in the regulation of exploration and exploitation of petroleum resources in both State and Commonwealth territorial waters.

7.5.2.1 *Victoria*

Offshore oil and gas approvals in Victorian waters (i.e. within 3 nautical miles) are administered under the Victorian *Petroleum (Submerged Lands) Act 1982* and the *Petroleum (Submerged Lands) Regulation 2001.*

The Victorian *Petroleum (Submerged Lands) Act 1982* mirrors the Commonwealth *Petroleum (Submerged Lands) Act 1967*. Approvals required for Victorian waters are identical to that of Commonwealth waters.

Offshore oil and gas approvals in Commonwealth waters are administered under the Commonwealth *Petroleum (Submerged Lands) Act 1967* and incorporated acts, including the *Petroleum (Submerged Lands (Pipelines)) Regulations 2001.*

The term of the offshore pipeline licence is 21 years.

7.5.2.2 *Western Australia*

Offshore pipelines in Western Australia are administered under the *Petroleum (Submerged Lands) Act 1982* for State coastal waters (to a limit of three nautical miles seaward of the base line).

Beyond State coastal waters, the offshore adjacent area (Commonwealth waters) is administered by a Joint Authority comprising the Commonwealth

Minister for Industry, Tourism and Resources and the Western Australia *Minister for State Development*, under the Commonwealth's *Petroleum (Submerged Lands) Act 1967* and incorporated acts, including the *Petroleum (Submerged Lands (Pipelines) Regulations 2001.*

7.5.3 Regulatory gaps in permitting for CO_2 transport in Australia

Generally the Australian approvals and easement protocols reflect those applicable in the UK, with requirements for ESs / EIAs and consultation with appropriate bodies.

Table 7.6 Summary of permitting issues for onshore CO_2 pipeline transport under Australian law

CO_2 transport issue	Gap	Partially Covered	Covered
Population density		Covered by existing gas transportation regulations. Similar signage requirements could be adopted from Texan standards.	
Removal of Water	Unclear what the transmission standards will be for CO_2		
Permitted development rights			Covered by existing gas transportation regulations
Definition of a Gas	Legislation will need to be amended before the same law can be applied to CO_2 pipelines. WA State legislation has already been amended to include CO_2 within the definition of "petroleum"		
Hazard / risk			Covered by existing gas transportation regulations

8 PERMITTING ANALYSIS FOR CO_2 INJECTION AND STORAGE

8.1 INTRODUCTION

This section presents some of the key existing regulatory and permitting requirements that could potentially be applicable to any operator considering the option of storing CO_2 in a geological reservoir in Europe, Australia and the USA.

The issues relevant to permitting presented by the geological storage of CO_2 are considered in the previous Sections of the report (*Section 4*).

Whilst some broadly analogous regimes for permitting exploration, production and/or temporary containment of fluids in the subsurface exist, the long term storage of CO_2 is largely unprecedented, and may ultimately require a whole new set of laws and regulations to be developed in order to ensure safe and reliable operation of geological storage sites. Moreover, there are fundamental differences in environmental permitting approaches adopted across different jurisdictions under study. Consequently, some jurisdictions (principally the UK) have been reviewed in greater depth. A brief summary of each regime is outlined as follows:

The UK is required to adhere to European Union legislation (unless specific exemptions are sought, which is not the case for any environmental laws). In particular, one of the key permitting requirements this analysis has revealed is the need for an environmental impact assessment across various parts of the CCS chain. Under the EU EIA Directive, a significant body of evidence must be provider by a project developer about the potential environmental impact of the proposed project (see *Section 6.2.3*). If CCS operations - and in particular storage site development - were to trigger EIA requirements, then there will be a *burden of proof* upon project developers to demonstrate to key stakeholders that no adverse environmental effects would be created by the proposed site. Moreover, they must convince statutory bodies and other competent authorities (regulators) that the site will not impede their capacity to fulfil their statutory duties in relation to environmental protection. As a consequence, the process can become iterative in nature until parties are satisfied that it is safe to proceed, or the project is rejected. For this reason, considerable detail on the EIA approvals process has been included under the UK section. Such rigorous permitting requirements are born out of the need to provide sufficient environmental safeguards in the highly populous regions of northern and western Europe.

Australia, to date, has taken a lead globally in developing regulations that can accommodate CO_2 injection and storage. However, this has largely been through secondary amendments to primary legislation relating to petroleum production, and not through the development of direct primary legislation (see later Sections). Australia also has a well-evolved environmental approvals process – based around EIA - that broadly reflects the approvals process in operation in the UK. Some details have been provided about this process.

The USA has a well-developed regulatory regime for the management of underground injection of various fluids, based around groundwater protection legislation. This regime can provide some useful insights on the type of regulatory system that could emerge for CO_2 injection and storage globally. There is a fundamental difference in permitting approaches in the US, relative to the UK and Australia. Whilst in the USA some Federal funded programmes and projects are required to undertake an environmental assessment or impact study (under NEPA, see *Section 8.4.3.1*), and some States require that an EIA be compiled by the State regulator prior to them permitting certain projects, no obligation exists for the project developer to prepare an EIA, unlike in Europe or Australia. A US-based private developer may wish to undertake an environmental assessment scoping study in order to identify the permitting requirements of the project, but there is no *burden of proof* on them to demonstrate that the project will not have adverse effects in the environment, other than through application of specific permits relevant to the project (as outlined in *Section 8.4*). Also, there is no obligation for the developer (although the State authorities might wish) to consult on the environmental impacts, unlike in Europe or Australia. That said, on the whole, the wide ranging and rigorous environmental permitting regime in operation in the USA provides strong safeguards against environmental damage.

Canada has 15 years experience of regulating acid (sour) gas transportation, injection and storage, operated at both the Federal and Provincial level. This framework provides an excellent analogue to CCS operations, albeit with only a weak framework for handling the long term storage issues. Canada also has a well developed environmental assessments and approvals process at both Federal and Provincial levels, and this could be a major component of CCS operations going forward, although to date this regime has not applied to acid gas injection operations.

A review of the existing regulatory frameworks that could apply to CO_2 storage in the jurisdictions under study are reviewed below:

8.2 CONSIDERATIONS IN A UK CONTEXT - ONSHORE

8.2.1 *Introduction*

There are currently no permitting regimes applicable to the on- or offshore injection and storage of CO_2 in the UK. Furthermore, the UK has a very complex system of planning law which in a large part requires consideration on a case by case basis for large scale infrastructure projects, such as a CO_2 storage site development. This is further complicated by the fact that it is unclear how CO_2 will be interpreted in the licensing and planning regime, i.e. whether it will broadly follow the regime for petroleum exploration, minerals and mining exploration, or be developed from a whole new set of primary legislation. Thus the full breadth of UK planning law is far too lengthy and complex to be considered in this report, but some observations based on expert judgement by the authors has been made as to the likely permits that might be required across the storage site project cycle, namely:

⇒ **Site selection**: oil and gas and/or mineral exploration regulations;
⇒ **Site development**: existing permitting regimes for constructing large scale infrastructure projects and underground storage permitting, such as natural gas stores;
⇒ **Site operation**: legislation which covers industrial plants and underground storage of gases;
⇒ **Site decommissiong**: based on current practice for large-scale extractive industry projects.

Based on the project-cycle outlined, a proposed permitting route map has been laid out below (*Figure 8.1*).

8.2.2 *Site Selection*

Existing oil and gas activities both on- and offshore within the UK are largely regulated through the Petroleum Act (1998). The *Secretary of State for Trade and Industry*, via the *UK Department of Trade and Industry*: *Oil and Gas Directorate, Licensing and Consents Unit* (1), issues licences to individual developers to explore for onshore petroleum resources. Under the *Petroleum Act 1998*, petroleum is defined under *Section 1*

> *(a) … any mineral oil or relative hydrocarbon and natural gas existing in its natural condition in strata;*

Consequently, CO_2 storage site selection could not be considered under the regime without a change in the definition of petroleum (2). However, the Act would seem the most appropriate overarching piece of legislation under which to consider the approach taken to CO_2 storage site selection.

(1) Although another competent authority could be specifically established for CCS regulation.

(2) Whilst such an regulatory approach seems somewhat unorthodox, a similar approach ahs been adopted by the Western Australian Government (see *Section* 8.5)

The Act gives exclusive rights under *Section 2* of:

….searching and boring for and getting petroleum…

..to Her Majesty, with the licensing of exploration and exploitation vested to the Secretary of State to enforce.

Whilst the *Petroleum Act 1998* could be used to regulate CO_2, it would require the development of new primary or secondary legislation to amend the existing Act. In this case it seems more likely that some form of new primary or secondary legislation would be needed specific to CO_2. Nevertheless, the regime does provide a suitable basis upon which to assess how permitting for storage site development may evolve.

The *Petroleum Act 1998* in the context of onshore site selection is discussed below:

8.2.3 *Onshore site surveying rights*

Prior to any exploratory work being undertaken in a particular area, agreement from the person owning the subsurface mineral rights will be required. In most cases in the UK, these are held by the person with the surface land rights, although in areas with a history of subsurface mineral extraction, subsurface rights may have been separated from the surface rights. The *UK Land Registry* can provide information about land-owners.

Subject to agreement of the person holding the subsurface mineral rights, some type of license to exploit the subsurface will be required.

Under mineral planning legislation, permission from the local *Mineral Planning Authority* (MPA) will be necessary, which is usually managed at the level of the County Council or unitary local authority. Permission will only be granted by the MPA subject to the restrictions laid out in the authorisation, taking into account appropriate planning guidance issued by the *Office of the Deputy Prime Minister* (ODPM).

Under the Petroleum Act 1998, a single licence, the *Petroleum Exploration and Development Licence* (PEDL) which is issued by the Secretary of State, confers the right to explore for petroleum onshore – in fixed blocks – to the licensee.

Whilst the principal purpose of the license is the conferring of rights to the licensee to exploit discoveries, it also enables the holder to undertake the following:

- *seismic investigations:* subject to notifying the DTI and consulting the local planning authority;

- *drill wells*: subject to the permission of the landowner / occupier and the granting of planning consent under the *Town and Country Planning Act 1990*; and
- *develop wells*: if the site is considered suitable.

(*see below for more details*)

Obtaining a PEDL for drilling and developing consents does not confer the responsibility of the licensee from exemption under other regulatory requirements such as the need to gain access rights from land owners, health and safety regulations, or planning permission from relevant local authorities. In a large part, these requirements are governed by the *Town and Country Planning Act 1990*.

Thus, whether the PEDL approach would be broadly applicable to CCS operations is not necessarily clear, although it does provide a useful framework in which to consider licensing across the project lifecycle, and is considered further in proceeding sections.

8.2.4 Planning

A PEDL is split into a number of different phases, referred to as 'Terms', which last for a fixed period based around different elements in the lifecycle of a petroleum field development, namely: exploration, appraisal, production. At the end of each Term, the licensee is obliged to apply for a new license, based on the actions for the next phase of field development.

For a CO_2 storage site, the issues associated with storage site selection, as outlined in *Section 4.3.3*, could be broadly analogous with the types of issues that would need to be agreed in the *Work Programme* under a PEDL. This might include evidence that:

⇒ permission has been granted from land owners,
⇒ the local authorities have been consulted prior to seismic investigations,
⇒ planning permission has been obtained prior to the drilling of exploratory wells and
⇒ the EA/SEPA has been consulted at all times in relation to the disposal of waste from site etc.

Under PEDL, if the *Work Programme* is completed successfully then the licensee can apply for a second Term, covering 'appraisal' and 'production' of the field. In the same way as for exploration, the licensee and the DTI must then agree a *Development Plan* covering the next phase of activities.

The analogue with CO_2 storage can broadly be drawn with regards to storage site development, as outlined in *Section 4.3.4*. The issue covered in that Section provides a useful guide to the types of issues that may need to be resolved in a *Development Programme* for a CO_2 storage site.

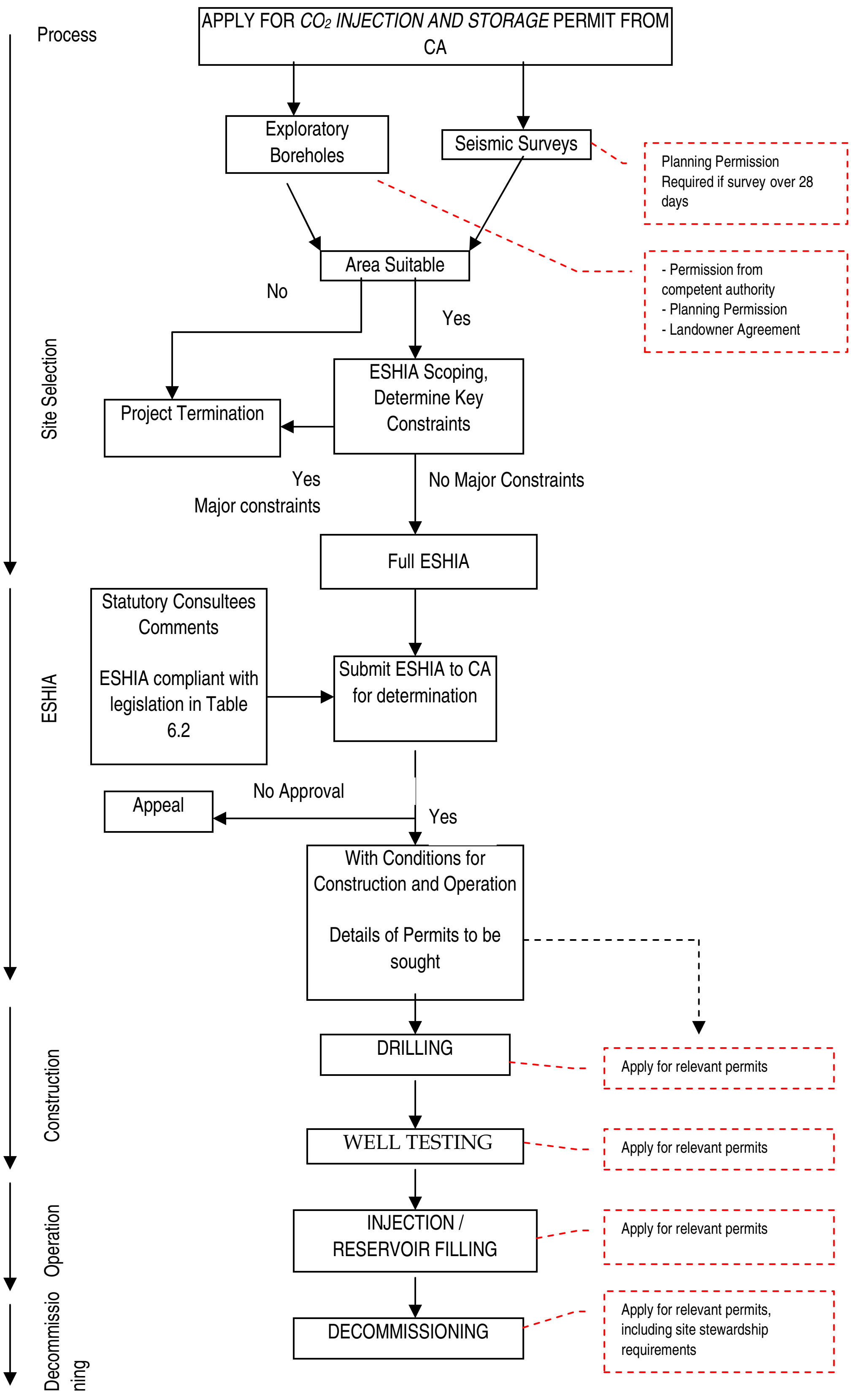
Using the analogy to draw conclusions about how storage site licensing might develop, it is likely that a *Development Programme* might include evidence of how the licensee/developer has considered the environmental and safety aspects associated with development, such as:

- An environmental statement
- A health risk assessment
- A suitable site monitoring programme, and
- A statement on decommissioning

Whilst the petroleum licensing regime outlines a useful framework under which CO_2 storage site development could be regulated, other specific permits will likely be necessary during development of a sites, as reviewed below.

A process / permitting flow diagram is provided in *Figure 8.1*. The following text accompanies the diagram.

Figure 8.1 Possible permitting critical path for a CO_2 storage site (on or offshore)



8.2.5 *Geological and geophysical surveying*

Much research has been undertaken into the suitability of different geological structures for CO_2 storage in the UK, principally by the *British Geological Survey* (BGS). Based on available information, a storage site developer would be able to identify areas where geological CO_2 storage may be possible. Availability of CO_2, and the cost of transportation will also be an important consideration in site location planning. Once these issues have been resolved, then the primary data collection will be necessary via direct observation and intrusive measurements. Much of this information will be obtained through physical surveys, including well bore holes, geomagnetic measurements, drillings, and seismic surveys.

As suggested in the previous section, specific authorisation from the local planning authority will be necessary prior to undertaking this type of survey work. The types of permitting issues for these activities are reviewed below:

8.2.5.1 *Seismic Investigations*

The most common method is vibroseis, the use of sonic waves created by vehicles fitted with vibrator pads. Shot holes are not needed, however the vehicles probably have to leave roads and tracks to gather the data needed. This could lead to damage to surrounding vegetation.

Under PEDL, prior notification must be given to the relevant local authorities if the onshore survey is planned to be less than 28 days. Also, under 'permitted development rights' (*Town and Country Planning (General Permitted Development) Order 1995*) *Section 22* of *Schedule* 2 mineral exploration using boreholes etc. can be carried out without a permit, so long as it is not for the exploration of petroleum (*Box 8.1*). Thus, unless a PEDL or equivalent is required for CO_2 storage site surveying activities, then providing the conditions laid in *Class A* of *Section 22* of *Schedule 2* of the 1995 Order are met, then exploration activities of less than 28 days are permitted, subject to the requirements laid down in *Article VII* of the Order.

Prior to carrying out any work the developer must also determine whether the area to be surveyed is a protected site e.g. an *Area of Outstanding Natural Beauty*, *Site of Special Scientific Interest*, *National Park* or is know to contain any protected species of flora and fauna. Appropriate mitigation measures must be employed depending upon the level of protection of the site. Developers will need to seek advice from the local authorities on a case-by-case basis.

If the planned survey will last more than 28 days then formal planning permission is likely to be required. This will include consultation with statutory bodies' e.g. English Nature, the EA etc. In all cases the landowners must be notified prior to any surveying [(1)].

(1) The UK Land Registry holds information on land owners.

Box 8.1 *Section 22 of Schedule 2 of Town and Country Planning (Permitted Development Rights) Order 1995*

MINERAL EXPLORATION
Class A

Permitted development

A. Development on any land during a period not exceeding 28 consecutive days consisting of-

(a) the drilling of boreholes;
(b) the carrying out of seismic surveys; or
(c) the making of other excavations,

for the purpose of mineral exploration, and the provision or assembly on that land or adjoining land of any structure required in connection with any of those operations.

Development not permitted

A.1 Development is not permitted by Class A if-
(a) it consists of the drilling of boreholes for petroleum exploration;
(b) any operation would be carried out within 50 metres of any part of an occupied residential building or a building occupied as a hospital or school;
(c) any operation would be carried out within a National Park, an area of outstanding natural beauty, a site of archaeological interest or a site of special scientific interest;
(d) any explosive charge of more than 1 kilogram would be used;
(e) any excavation referred to in paragraph A(c) would exceed 10 metres in depth or 12 square metres in surface area;
(f) in the case described in paragraph A(c) more than 10 excavations would, as a result, be made within any area of 1 hectare within the land during any period of 24 months; or
(g) any structure assembled or provided would exceed 12 metres in height, or, where the structure would be within 3 kilometres of the perimeter of an aerodrome, 3 metres in height.

Conditions

A.2 Development is permitted by Class A subject to the following conditions-
(a) no operations shall be carried out between 6.00 p.m. and 7.00 a.m.;
(b) no trees on the land shall be removed, felled, lopped or topped and no other thing shall be done on the land likely to harm or damage any trees, unless the mineral planning authority have so agreed in writing;
(c) before any excavation (other than a borehole) is made, any topsoil and any subsoil shall be separately removed from the land to be excavated and stored separately from other excavated material and from each other;
(d) within a period of 28 days from the cessation of operations unless the mineral planning authority have agreed otherwise in writing-
- (i) any structure permitted by Class A and any waste material arising from other development so permitted shall be removed from the land,
- (ii) any borehole shall be adequately sealed,
- (iii) any other excavation shall be filled with material from the site,
- (iv) the surface of the land on which any operations have been carried out shall be levelled and any topsoil replaced as the uppermost layer, and
- (v) the land shall, so far as is practicable, be restored to its condition before the development took place, including the carrying out of any necessary seeding and replanting.

NOTE: The storage site developer would be required to consult the legislation to check whether his activities qualified as Class A or Class B (not listed) as specific in Article VII of the Order.

8.2.5.2 *Exploratory Boreholes*

Borehole investigations may also be necessary. If the borehole development will last for less than 28 days, and providing that CO_2 storage site exploration is classified as mining exploration, the conditions outlined in the above will apply (*Box 8.1*) and no specific authorisation will be required (subject to local planning approval). Otherwise, prior to commencement of the borehole drilling (following permission from the competent authority) planning permission must be obtained from the relevant body (either the DTI licensing and Consents unit under *petroleum* or the *Mineral Planning Authority* or the

ODPM under mineral licensing regimes). This is likely to include a requirement to undertake an Environmental Assessment which must be submitted with the planning application. Consultation with the relevant statutory bodies will also be required, and permission granted subject to the conditions laid down in the permit.

If the site is considered to be suitable for CO_2 storage, the developer is then likely to be required to undertake a wider risk assessment, covering the risks posed to both the natural environment and human health, before progressing with an application to store CO_2.

8.2.6 Environmental, Social, and Health Impact Assessment

The first stage of the ESHIA process will be to carry out scoping which will ensure early communication with key statutory consultees to ensure that all the major environmental, social and health impacts have been addressed.

The full ESHIA can then be developed. This would likely include a risk assessment of activities which could pose a threat to human health, such as a CO_2 leakage from the storage reservoir. In addition to the normal content of an ESHIA for an onshore exploration well, the assessment would likely include a thorough investigation into the potential risks associated with CO_2 injection and storage. Thorough and detailed reservoir modelling would likely form a central component of the ESHIA, the results from which will play a central role in determining the environmental and social viability of the project (1).

The ESHIA would then be submitted to the CA for review who will seek comments from the statutory consultees. These consultees would review the project to ensure compliance with all relevant legislation, the key components of which are outlined in *Table 8.1*.

Table 8.1 Key UK legislation

Legislation	Summary of Use	Competent Authority
Town and Country Planning Act 1990	Planning permission will be required for all onshore developments	Local Authorities / County Councils
EC Directive (85/337/EEC) Assessment of the effects of certain public and private projects on the environment	Requires an ES to be prepared as part of the planning process	Local Authorities
EC Directive (92/43/EEC) Conservation of natural habitats and of wild flora and fauna and; Conservation (Natural Habitats) Regulations 1994	Will require the development of any CO_2 storage site to take account of special areas of conservation in the environmental assessment	Local Authorities

(1) Note: the UK does not possess any permitting regimes analogous to the UIC Programme in the US, hence the consideration of sub-surface impacts would likely be brought in via an ESHIA requirement on a developer.

Legislation	Summary of Use	Competent Authority
Seveso II Directive (96/82/EC); Control of major hazards and accidents; and • Planning Regulations 1999 • Control of Major Accidents and Hazards Regulations 1999 (COMAH)	A licence will be required for the storage of listed hazardous substances Requires operators to implement certain management practices and report to competent authorities (See *Section 6.2.7*)	Local Authorities / the EA / SEPA
EC Directive (80/68/EEC) Groundwater; and Groundwater Regulations 1998	Discharges of listed substances which could pollute groundwater require authorisation	The EA / SEPA
Environmental Protection Act 1990: Part II; and Waste Management Licensing Regulations 1994	Requires that most wastes be disposed of at a facility operated by the holder of a suitable Waste Management Licence	The EA / SEPA
Water Framework Directive (2000/66/EC)	Requires "good" chemical and ecological status of surface and groundwaters to be maintained and/or enhanced	The EA / SEPA
Environment Act 1995 Part IV; and Air Quality Regulations 2000	Sets emission limits for certain substances	Local Authorities
Control of Pollution Act 1990 Part III; Environmental Protection Act 1990 Part III; and Environment Act 1995, Part V	Requires local authorities to take action where noise limits are exceeded	Local Authorities

8.2.7 *Site Development*

8.2.7.1 *Construction*

Many of the permits and licences required for construction of the storage site would most likely be the same as for those identified above. This will include:

⇒ waste management licences for all hazardous waste streams taken off site, granted by the EA or SEPA;
⇒ a permit from the EA/SEPA for drilling through any aquifers;
⇒ a licence from the EA/SEPA for water abstraction for drilling;
⇒ a discharge licence from the EA/SEPA for any water discharge;
⇒ a PPC permit from the EA/SEPA for any venting during testing etc (see *Section 6.2.2* and *Annex I*)

All permitting requirements will be identified during the ESHIA process.

8.2.8 *Reservoir Filling (Operational Phase)*

Due to the particular characteristics associated with CO_2 storage sites, it is envisaged that the majority of the permits required will have been gained in the earlier planning phases of the development. Once all of these have been agreed and the reservoir is operational, it is envisaged that only a couple of permits will be required for continued operation of the facility. This might include a PPC permit for air and waste emissions (e.g. for venting) and possibly a permit which considers emergency response procedures, similar to requirements laid down by the Seveso II Directive/COMAH Regulations (see *Sections 6.2.7* and *Annex I*). The licence granted prior to operation of the facility following submission of the ESHIA would likely include such items as:

⇒ safe operating procedures;
⇒ continuous monitoring devices;
⇒ monitoring of the subsurface plume of CO_2 and the surrounding land for signs of any environmental or human health impacts from displacement of existing reservoir fluids or for early signs of storage site CO_2 seepage; and
⇒ the procedures for reporting of any emissions, and reconciling these under the EU ETS Directive (see *Section 6.2.5*) and reporting to the UK Government as part of its National Communication on the greenhouse gas inventory to the UNFCCC.

8.2.9 Site Decommissioning

Decommissioning activities are likely to be covered as part of the planning consent and ESHIA compiled prior to construction of the facility, based on the projected reservoir capacity and fill-rate. It is envisaged that the decommissioning plan will be expanded and refined prior to closure of the plant to ensure that Best Available Techniques available at the time are taken into account and implemented, and also to ensure that the plan is in line with legislation current at the time.

At this time it is likely that the CA may issue a permit for site closure. This would include the specific site post-closure stewardship requirements, and outline a date or outcome that would trigger cessation of liabilities for the [former] site operator.

8.3 CONSIDERATIONS IN THE UK CONTEXT - OFFSHORE

8.3.1 *Introduction*

Offshore permitting requirements for the development of CO_2 storage reservoirs under the seabed present slightly different issues to onshore. For example, for UK territorial waters the only land owner is the Crown Estate, from whom permission would be needed prior undertaking any activities. Consideration of the impacts of international treaties, for example the OSPAR and London Conventions will also need to be made (1).

In the following section, the permitting processes outlined have been drawn from the oil and gas regulatory framework, which broadly parallels the types of issues that could be presented by CO_2 storage site development.

8.3.2 *Site Selection*

Existing offshore oil and gas activities are permitted by the DTI Oil and Gas Directorate, in much the same way as for onshore, albeit with slightly different permit types and approaches. The process of identifying and selecting offshore CO_2 storage sites, as with onshore, could be regulated either through a licensing round as happens with offshore petroleum wells or via other yet-to-be established procedures (2).

Offshore oil and gas developments are also regulated via a series of Petroleum Operations Notices (PONs), which lay out a range of specific requirements for operators to comply with during reservoir development and operation.

For example, the preliminary geological and geophysical survey work, such as seismic investigations, borehole investigations, shallow drilling and gravity / magnetic surveys, will all require consent form the CA, most likely by way of existing PONs. The developer would need to commence early discussions with the JNCC and the CA to determine whether the area in question is particularly sensitive to cetaceans and / or in a site designated under the EU Habitats Directive. The developer would also need to identify whether the area is an important fishing ground. Following this it is likely that the developer would be required to submit an EA.

8.3.3 *Drilling a Well*

An EIA for certain types of offshore oil and gas projects is required throughout the European Union by the EU EIA Directive (85/337/EEC and 97/11/EC; see *Section 6.2.3*). For offshore, the Directive is transposed into UK national legislation via the *Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (SI No. 1999/360)* which

(1) Although consideration of OSPAR and London Convention issues will not be reviewed here, a number of reviews of the status of CCS under OSPAR and the London Convention are widely available. A good overview of the status of CCS under International Law can be found at: http://www.iea.org/dbtw-wpd/textbase/work/2004/storing_carbon/Thomson.pdf
(2) Some observers have suggested that the UK might need to establish a Carbon Dioxide Capture and Storage Authority.

covers wells, field developments and pipelines in the United Kingdom Territorial Sea and on the United Kingdom Continental Shelf (UKCS).

In order to comply with the requirements, in most cases a PON 15 or application form will be submitted seeking a direction from the Secretary of State. For some projects covered by the regulations, an EIA may not be required, but for others it will remain mandatory. Direction in this regard will be given by the Secretary of State.

SI No. 1999/360 requires the CA to take into consideration environmental information before making decisions on whether or not to authorise various offshore projects. Where an ES / EIA is prepared it will include details of the existing baseline environment, potential impacts which may result from the project and any measures which the operator intends to take to mitigate that impact. The ES has to be subject to a period of public consultation during which time any person or body can make their views known. The CA will subsequently make the decision as to whether the proposed project can go ahead.

The developer would also need to complete PON 16 and PON 15B which are an application for consent and a Chemical Permit Application respectively. *Figure 8.1* provides a broad overview of the main legislative controls which will apply whilst *Table 8.1* provides a summary of the types of International and UK legislation which statutory consultees will address.

Table 8.1 Key Marine Regulations for Offshore Drilling

Item	Basis	Key issues
MARPOL (International Convention on the Prevention of Pollution from Ships)	International (World)	• Only *Annex II* substances can be carried by support vessels. • Competent authorities must be notified of chemicals used on support vessels. • Discharge of category A, B or C substances or other residues containing them is prohibited. • Discharge of oil or oily mixtures is prohibited unless below 15 ppm oil without dilution. • Floating or fixed rigs are considered as ships i.e. oil content of effluents must not exceed 15 ppm. • Tankage should be provided to receive residues which cannot be treated to 100 ppm. • Disposal of garbage overboard is prohibited.
OPPRC (Oil Pollution Preparedness and Response Convention) 1990	International (World)	• Operators of offshore units are required to have oil pollution emergency plans which are co-ordinated with the national system
OSPAR (Oslo and Paris Conventions) regarding conservation and preservation of the North East Atlantic, 1992	International (Eastern Atlantic countries)	• Hydrocarbons in produced water should be less than 40 ppm (possibly 30 ppm in the near future). • OSPAR are likely to develop a set of regulatory principles for CCS under one of its subsidiary scientific and technology bodies.

Item	Basis	Key issues
London Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other matter, 1972	International (World)	• Designed to regulate the types of material discharged and dumped at sea. • The role of the CCS under the London Convention is subject to considerable debate at present, and has yet to be resolved.
POPA (Prevention of Oil Pollution Act 1971 as amended)	UK	• Oil spills must be reported to the competent authorities and monitored. • The licensee must prevent the escape of petroleum into waters in the vicinity of the exploration / production area.
Merchant Shipping (Prevention of Pollution) Regulations 1983	UK	• Installations shall be equipped as far as practicable with oil discharge monitoring and control systems, oily water separators and tanks for residues/sludge (as per MARPOL)
Merchant Shipping (Prevention of Pollution by Garbage) Regulations 1988 and 1993	UK	• Disposal of garbage from offshore installations is prohibited, except macerated food wastes
Merchant Shipping (Prevention of Oil Pollution) Regulations 1996	UK	• 15 ppm limit for oil in discharges
Merchant Shipping (Oil Pollution Preparedness and Response) Regulations 1998	UK	• Installations must have a UK or international Oil Pollution Prevention certificate
Pollution Prevention and Control Offshore Chemicals Regulations 2001	UK (under amendment as part of 2004 regulations)	• These regulations will be enacted under the *Pollution Prevention and Control Act 1999.* • The Regulations will control chemicals in offshore E&P. Operators will require permits from DTI for the discharge or use of all chemicals offshore.
Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001	UK	• The provisions of the Regulation enact the *Habitats Directive* and *Wild Birds Directive* i.e. Natura 2000 sites and the protection of listed habitats and species, will apply to all UK waters, including those outside the 12 mile limit.

In addition to international and UK regulations, a variety of government and industry guidance exists relating to the environmental performance of exploration and production operations. This is summarised in *Boxes 8.1* and *8.2.*

Box 8.2 *Offshore Chemical Notification Scheme (OCNS)*

The UK Revised OCNS contains classifications for those chemicals permitted for use in offshore hydrocarbon exploration and production activities. The Revised OCNS is a mandatory scheme administered by the DTI. It was applied in December 1996, replacing the existing voluntary scheme and thereby complying with the requirements of the Harmonised Offshore Chemical Notification Format (HOCNF) devised by OSPARCOM.

The objective of the revised scheme is, in essence, to prevent unacceptable damage to the marine environment by discharges or accidental losses from offshore E&P activities. This is achieved in a number of ways, as summarised below.

- *All chemicals in use are assigned hazard categories; this also enables operators to consider environmental factors when selecting products for use offshore.*
- *The OCNS provides for consultation between operators and the government in the case of proposed large scale chemical usage, with an associated Risk Assessment.*
- *Operators and their sub-contractors are provided with information on chemicals and components which are prescribed and considered unsuitable for use offshore.*

The scheme provides information to the government regarding the likely levels of use of various substances offshore.

Box 8.3 *Control of Offshore Chemicals within UK Waters*

The OSPAR decision introducing a Harmonised Mandatory Control Scheme (HMCS) for the use and discharge of chemicals offshore was adopted at the OSPARCOM meeting in mid-2000 and the draft Offshore chemicals Regulations were issued for comment in January 2001. A regulatory regime has been introduced under which operators will require a permit to use and discharge chemicals in the course of the exploration and exploitation of oil and gas resources within the UK Continental Shelf (UKCS).

An essential element will be the maintenance of a database containing information on offshore chemicals according to the OSPAR Recommendation on a Harmonised Offshore Chemicals Notification Format (HOCNF). The database will also include a calculated PEC/PNEC (Predicted Environmental Concentration/Predicted No Effects Concentration) relating to each Chemicals discharge under standardised conditions.

8.3.4 *Food and Environmental Protection Act 1985 Part II (Deposits in the Sea)*

The *Food and Environmental Protection Act 1985* (FEPA) [(1)] provides the statutory means by which the UK can meet its obligations under the London Convention and OSPAR, which address the dumping of waste at sea. Like the London Convention and OSPAR, it was not drafted with the concept of CCS in mind, and thus presents ambiguities in its interpretation when considering CO_2 storage in the sub-sea bed and use of CO_2 for EOR operations.

Under *Part II* of *FEPA*, a *License for the Deposit of Substances or Articles in the Sea* is required. The provisions laid out in *Part II, Section 5* require a license for the a number of activities:

> *(a) for the deposit of substances or articles within United Kingdom waters or United Kingdom controlled waters, either in the sea or under the sea-bed ---*

(1) FEPA (1985) replaced the Dumping at Sea Act (1974)

(iii) from a structure on land constructed or adapted wholly or mainly for the purpose of depositing solids in the sea;

(b) for the deposit of substances or articles anywhere in the sea or under the sea-bed-

(ii) from a container floating in the sea, if the deposit is controlled from a British vessel, British aircraft, British hovercraft or British marine structure;

Under S*ection 5 (a) (iii)* it seems that the deliberate capture and export of CO_2 from power station flue gas would be covered. However, exemptions are possible by order or by statutory instrument by Ministers under *Section 7* of the Act.

In the case of deposits from hydrocarbon production – including drill cuttings - *FEPA* licenses are controlled by the DTI Oil & Gas LCU, and issued by either the Secretary of State for Trade and Industry (in Scotland) or *Defra*, *Marine Consents and Environmental Unit* (MCEU).

Operations involving the *onsite* injection of operational wastes are exempted from *FEPA Part II* requirements, as a consequence of *Section 15* of the *Schedule* to *Article 3* of *The Deposits in the Sea (Exemptions) Order (1985)*, *SI No 1699*. *Section 15* of the Schedule refers exemptions for the:

deposit under the sea-bed on the site of drilling for, or production of, oil or gas of any substance or article in the course or such drilling or production.

For offsite injection of operational wastes, a *FEPA Part II* license is required. There is some ambiguity about whether CO_2 injected onsite would be subject to *FEPA Part II* licensing requirements, as the CO_2 would not have been produced onsite. It is therefore likely that a *FEPA Part II* license will be required for EOR operations, although the provisions of the existing licensing arrangements do not explicitly cover the use of CO_2 for EOR, unless the CO_2 used is produced on the platform.

It is also worth noting that under Section 8 of the Act, alternative disposal options must be considered in the case of:

8. -- (2) … where it appears to a licensing authority that an applicant for a licence has applied for the licence with a view to the disposal of the substances or articles to which it would relate, the authority, in determining whether to issue a licence, shall have regard to the practical availability of any alternative methods of dealing with them.

This specific Section is likely to lead to the requirement for some kind of guidance to regulators in respect of power station flue gas, which would otherwise be emitted direct to the atmosphere as a more practical alternative method of disposal.

Currently there are a broad range of *FEPA Part II* license application forms, although none relate to the injection of CO_2 in the seabed. Such a license application form might need to be developed should it be considered that *FEPA Part II* is applicable to CCS operations.

Most *FEPA Part II* license applications require the applicant to provide the following type of information (*Box 8.4*)

Box 8.4 FEPA Part II license application information requirements

- *Details of duration of the disposal operations – FEPA Part II* licenses are time limited for 10 years, with an option for renewal;
- *Submission of a method statement* for the transport and disposal of the material – including details of how the waste will be transported to the installation undertaking the disposal;
- *Details of the materials to be disposed of* - Including maximum annual quantities scheduled for disposal, and the maximum quantity scheduled for disposal over the licensing period (in metric tonnes).
- *Alternative means of disposal* (as outlined above)
- *Consultation with Conservation bodies*
- *Environmental assessment* – must be submitted with the application if one has been carried out;
- *Placement on the Public Register*

Some of these aspects relate directly to the types of issues considered relevant to licensing CO_2 storage sites, as outlined in *Section 4.3.5.* This suggests that elements of the FEPA licensing process could be developed into a broader CO_2 injection licensing regime. This would require development of a specific license application process for this type of operation, and the provision of guidance in relation to the Acts requirement for alternative disposal options.

8.3.5 Reservoir Filling (Operational Phase)

As with onshore wells the majority of permits to operate will have been obtained as part of the EIA process, however it is unclear at this time as to what such additional permits may be, although it could conceivably be a FEPA Part II license. Once all permits have been gained and the site is operational, then the only permits likely to be required will be for well maintenance activities (see *Figure 9.1*) and for any surveying / monitoring activities which may be required. It is presumed that as for an onshore well the ES will have covered areas such as

⇒ safe operating procedures;
⇒ continuous monitoring devices;
⇒ monitoring of the subsurface plume of CO_2 and the seabed for signs of any environmental or human health impacts from displacement of existing reservoir fluids or for early signs of storage site CO_2 seepage; and
⇒ procedures for the reporting of any emissions, and reconciling these under the EU ETS Directive (see *Section 6.2.5*).

8.3.6 *Site Decommissioning*

Figure 8.1 provides a summary of the permits required at present for the decommissioning and abandonment of offshore petroleum wells. It is envisaged that, due to the long term monitoring required, and to issues surrounding site stewardship, decommissioning activities will require much greater regulation. However the means for this long term regulation and monitoring is not in place within the UK legislative and permitting system at present. Some form of financial guarantees, such as indemnities may be a preferred option for long-term stewardship.

8.3.7 *Conclusions on CO_2 storage site permitting in the UK*

Whilst it seems unlikely that the UK would amend the *Petroleum Act 1998* in order that the licensing regime be applicable to CO_2 storage selection, the process provides a useful guide to how CO_2 storage site selection permitting could evolve in the UK, most likely through the enactment of new primary legislation.

The UK minerals exploitation permitting is largely controlled at a local authority level via the local *Minerals Planning Authority*. For large scale works or work that is deemed of high importance (as may be the case with CO_2 storage sites), then referrals can be made up to the Secretary of State (the Deputy Prime Minister) to make decisions regarding planning permission.

Whilst *FEPA Part II* does not address CCS operations in any way, through amendments and development of the licensing procedure could provide a useful interim measure to regulate CO_2 storage sites. This is because certain aspects of the regime bear significant resemblances to the types of permitting issues highlighted for reservoir filling in *Section 4.3.5*.

In general, given the lack of recognition of CO_2 in existing primary legalisation in the UK, in either petroleum regulations, gas regulations or minerals regulation, then it is likely that new primary legislation will be required prior to widespread deployment of activities.

Legislative developments on CCS storage site planning, site selection, operation and decommissioning at the European Union level will also need to be taken into consideration under UK law.

Note: It is not possible to present a coherent analysis of the gaps in permitting as outlined for CO_2 capture and transportation.

8.4 CONSIDERATIONS IN A US CONTEXT

Whilst geological storage options for CO_2 are varied, the most common form to date in the US is storage in underground oil reservoirs, often as a part of EOR projects. The US permitting system for injection of anthropogenic materials are well established due to a long history of waste injection and EOR activities. This means that CO_2 injection is likely to be accommodated in existing legislation.

A review of the underground injection permitting regime is presented below:

8.4.1 *The Underground Injection Control (UIC) Program*

The *Safe Drinking Water Act 1974* (SDWA) was promulgated by the EPA in response to "wide-spread and uncontrolled pollution of surface and subsurface waters". Under the SDWA, the *Underground Injection Control* (UIC) *Program* was established to provide assurance that injection of fluids below the ground surface would be undertaken in an environmentally safe and responsible manner. Approval of UIC wells requires demonstration that waste injection will not adversely affect drinking water supplies (generally through reservoir and ground water transport modelling) and appropriate financial commitments (often in the form of a guarantee) to ensure that well closures will be performed in accordance with UIC regulations at the appropriate time.

The Federal UIC Program was designed to enable State programs that meet federal standards to receive authority to regulate UIC activities within their State boundaries. In 1980, EPA promulgated regulations (*30 CFR 144*) that established minimum standards of performance for injection wells, including siting/construction standards, operational permit stipulations, testing, monitoring, and reporting. Most U.S. states adopted the EPA standards into state-specific UIC programs after 1980. For those states that did not develop state-specific UIC programs, EPA retains enforcement authority.

The EPA UIC program defines five well classifications:

Class I: wells used to inject liquid hazardous and non-hazardous wastes beneath the lowermost sources of potable ground water;

Class II: wells used to dispose of fluids associated with the production of oil and natural gas, enhanced oil recovery (using water or CO_2), and storage of liquid hydrocarbons (*Box 8.5*);

Class III: wells used to inject fluids for the extraction of mineral resources, exclusive of oil and natural gas; injection well technology is commonly used for the production of uranium, potash, and sulphur;

Class IV: wells used by generators of hazardous and/or non-hazardous wastes and radioactive wastes to inject fluids into or above a formation that contains potable water within one quarter mile of the wellhead (Class IV wells are prohibited in many states); and

Class V: miscellaneous injection wells that do not fall under Class I through IV; examples include geothermal wells, subsidence control wells, drainage wells, aquifer recharge wells, and experimental wells (*Box 8.5*) etc.

Box 8.5 ***The Weyburn Project***

In 2000, with a $20.5 million cooperative agreement with the Canadian Federal Government and the Saskatchewan Provincial Government, EnCana, a Canadian oil and gas company, began enhanced oil recovery (EOR) efforts using CO_2 to extend the life of the Weyburn oil field in south eastern Saskatchewan, Canada, by more than 25 years, anticipating the extraction of 130 million or more barrels of oil from the depleted field (the field is now owned by Apache (Canada) Ltd).

CO_2 Transportation: The CO_2 is produced from a coal gasification facility located in North Dakota, USA, and is transported to the Weyburn oil field via a 320-km pipeline, demonstrating the economic feasibility of long distance CO_2 transportation. According to project personnel, the Federal Energy Regulatory Commission (FERC) was not involved in reviewing or permitting transportation issues, as the pipeline does not cross state boundaries. Approvals were, however, needed from the Public Services Commission of North Dakota. Of the 199 EOR projects operating in 1998 active across the USA and Canada, 66 of these projects used miscible CO_2 floods, including the Weyburn oil field.

CO_2 Storage: Approximately 1/3 of the CO_2 used in EOR activities remains in the oil field. Researchers will gather information before and after CO_2 flooding to assess CO_2 as an oil extraction enhancement, and to analyse the conditions and behaviour of the CO_2 in the subsurface. Another element of the study is determining yield and storage capacity of the field to fully realize cost effectiveness; that is, determining the potential CO_2 storage capacity of the reservoir for every enhanced barrel of oil produced. No specific permitting issues arose during development of the EOR programme.

CO_2 Monitoring: The IEA Weyburn CO_2 Monitoring and Storage Project is coordinated by 20 research organizations in Canada, the USA, UK, France, Italy and Denmark. This international collaboration will improve the knowledge and understanding of geologic storage by monitoring the CO_2 that remains in the oil field over a 4-year period. Key objectives of this research are to study the geological, geophysical and geochemical aspects of the Weyburn oil field, and map the migration and distribution of existing formation fluids (including resident CO_2) as well as injected fluids.

8.4.2 CO_2 injection under the UIC program

Many State regulators in the US and researchers consider that CO_2 injection wells for CO_2 storage should be governed under *Class I* or *Class II* injection well requirements based on the following:

- *Class II* wells are currently used for EOR purposes.
- *Class I* wells would be the most appropriate class for all other CO_2 injection projects.

However, pilot projects, such as the Frio Project (see *Box 1.2)*, have been permitted as Class V experimental wells. The EPA and the *Interstate Oil and Gas Compact Commission* (IOGCC) has undertaken a provisional review of permitting issues for CO_2 geological sequestration. The review broadly concludes that the existing regulatory regimes in place for EOR, natural gas storage and acid gas injection provide a significantly robust regulatory regime to provide long-term assurance of secure storage, and that the natural gas storage statutes should be applied to CO_2 storage. A range of other recommendations are made by the IOGCC as to the appropriate regimes for regulating CO_2 geological sequestration operations (see IOGCC, 2005).

The US Federal government will likely turn to State-level UIC programs to administer, regulate, and permit injection of CO_2 specifically for greenhouse gas reduction.

Box 8.6 Frio Brine Pilot Experiment

The Frio Brine Pilot experiment is designed to field test modelling, monitoring, and verification techniques that can be applied to CO_2 storage in high-permeability, high-volume sandstones. The site is representative of a broad area that is an ultimate target for large-volume CO_2 storage due to favourable geologic conditions (the Frio Formation), and the hydrogeology consists of a saline aquifer, which cannot be utilized as a drinking water source. The unit underlies a concentration of industrial CO_2 sources and power plants along the Gulf Coast of the United States. Development of geologic storage of CO_2 in this region has excellent potential for the long term.

The Frio Brine Pilot experiment site is 30 miles (50 km) northeast of Houston, Texas, USA, in the South Liberty oil field. The area is located in a low topographic area along the lower coastal plain of the Gulf of Mexico on a terrace above the Trinity River. Originally developed as an oil field in 1950, the area is now densely wooded and has agricultural, rural residential, and other low-density uses.

Experiment objectives are to:

- Demonstrate that CO_2 can be injected into a brine formation without adverse effects on health, safety, or the environment;
- Determine the subsurface distribution of injected CO_2 using various novel monitoring technologies;
- Demonstrate validity of conceptual models; and
- Develop the experience necessary for success of large-scale CO_2 injection projects.

Injection of CO_2 took place in October 2004, and was permitted under the Texas UIC program. The injection well was classified as a Class V Experimental Well, though it could also have been classified as a Class I Non-hazardous Waste injection well. The CO2 was purchased commercially and transported to the site via tanker truck with DOT placards. An OSHA-compliant Health and Safety plan was developed for the project. Monitoring of CO_2 is conducted in the subsurface, on the ground surface and in ambient air with monitor points surrounding the injection site. Additional monitoring is performed via seismic reflection and refraction surveys to validate the site conceptual model.

For further information, see http://www.beg.utexas.edu/environqlty/co201.htm

8.4.3 Other relevant regulations

8.4.3.1 National Environmental Policy Act (NEPA)

Future CO_2 storage projects undertaken in conjunction with a U.S. Federal agency will likely be required to complete a NEPA review. NEPA was designed to ensure that government agencies complete a thorough review of all environmental considerations prior to any significant undertaking. Under NEPA, the *Council of Environmental Quality* (CEQ) was established in 1969. CEQ regulations state "government agencies shall make diligent efforts to involve the public in preparing and implementing their NEPA procedures." NEPA compliance documents include:

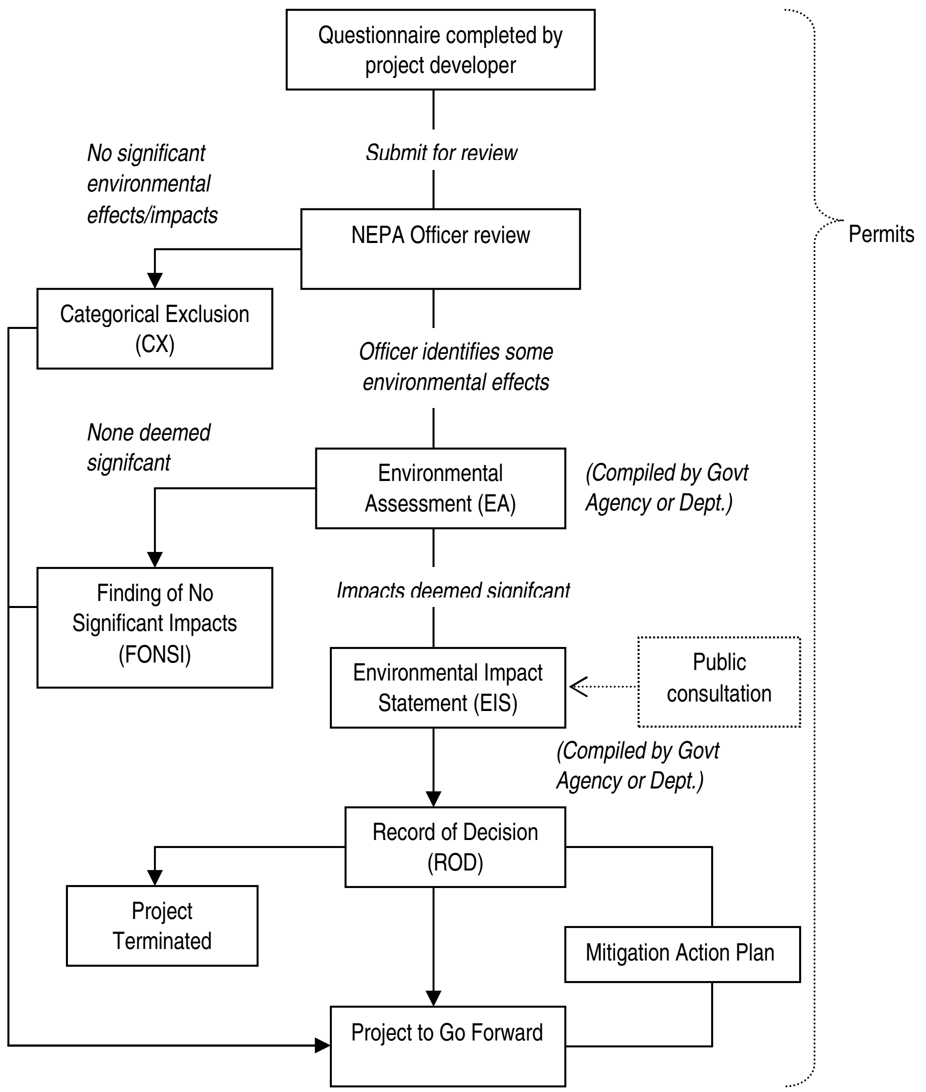
- Environmental Assessments (EAs) to determine if there are any significant impacts;
- Finding of no significant impacts (FONSI);
- Environmental Impact Statements (EIS) to analyse significant impacts; and
- Records of Decision. (see *Figure 8.2*)

NEPA also requires consultation with agencies or technical experts that have participated in the project planning process and have provided significant information and recommendations. The DOE *Order No. 0451.1B* (National Environmental Policy Act Compliance Program) provides guidance for NEPA reviews of DOE projects. For example the University of Texas Frio project (*Box 8.6)* underwent NEPA review since the funding for this project is through the DOE.

Currently, the US EPA is undertaking a "programmatic" EIA of the CO_2 sequestration research programme in the USA (which covers both biological and geological sequestration). Findings of this could mitigate the need for any project-specific EIAs under NEPA undertaken with Federal funding [(1)].

(1) This "programmatic" EIA can be considered broadly analogous with the SEA Directive requirements outlined in *Section* 6.2.4. This is fundamentally different to the EIA considerations outlined in the UK and Europe sections of this report.

Figure 8.2 ***EA and EIS permitting flow chart for Federal funded projects under NEPA***



8.4.3.2 *State level environmental impact assessment*

Most US States also place their own specific legislative requirements for the preparation of environmental assessments and statements for major projects, for example, the *California Environmental Quality Act*, *Minnesota Environmental Policy Act, 1973* and the *New York State Environmental Quality Review Act*. These laws require State and/or local public decision-makers to assess environmental significance prior to approving major project plans.

In all cases (NEPA, State legislation) the *burden of proof* falls on the relevant government agencies to prove that their decision regarding project approval would not lead to adverse effects on the environment.

8.4.4 *State-by-State Considerations*

CO_2 injection and storage is also subject to State regulations, and these can vary significantly. In general, States with low population density and/or previously established injection activities under UIC programs (e.g. Texas) will likely be more receptive to and prepared for the storage of CO_2 for climate change mitigation purposes. States with a high population density and/or very little previously established injection activities under UIC programs (e.g. Massachusetts) will have a steeper learning curve, lower level of regulator acceptance, and will be subject to a greater level of public scrutiny.

On 16 August 2003, the DOE identified seven partnerships of state agencies, universities, and private companies to form a nationwide sequestration network. These include:

- *West Coast Regional Carbon Sequestration Partnership* led by the California Energy Commission, Sacramento, CA, and made up of representative organizations from Alaska, Arizona, California, Nevada, Oregon, and Washington. The Province of British Colombia (Canada) joined in December 2004;
- *Southwest Regional Partnership for Carbon Sequestration* which will involve the efforts of 21 partners in eight states coordinated by the Western Governors' Association and New Mexico Institute of Mining and Technology, Socorro, NM;
- *Northern Rockies and Great Plains Regional Carbon Sequestration Partnership* which will be headed by Montana State University, Bozeman, MT, and cover Idaho, Montana, and South Dakota;
- *Plains CO_2 Reduction Partnership* which will extend across Minnesota, North Dakota, South Dakota, Nebraska, Iowa, Missouri, Wisconsin, Montana, Wyoming and three Canadian Provinces. It will led by the Energy & Environmental Research Center at the University of North Dakota, Grand Forks, ND;
- *Midwest (Illinois Basin) Geologic Sequestration Consortium* which will evaluate sequestration options in the Illinois Basin of Illinois, western Indiana, western Kentucky, Michigan, and Maryland. It will be led by the University of Illinois, Illinois State Geological Survey;
- *Southeast Regional Carbon Sequestration Partnership*, headed by Southern States Energy Board, Norcross, GA, and involving Arkansas, Louisiana, Mississippi, Alabama, Tennessee, Georgia, Florida, North Carolina, Virginia, Texas, and South Carolina;
- *Midwest Regional Carbon Sequestration Partnership* covering Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia and coordinated by the Battelle Memorial Institute, Columbus, OH.

The following sections describe State regulations for CO_2 storage and injection for several leading states in the US, including California, Oklahoma, Ohio and Texas (based on their geological suitability for CO_2 sequestration and their geographical representation across the regional partnerships outlined above):

8.4.4.1 California

California's UIC program

- ⇒ *Class I Wells* are governed by the Federal EPA. Only six *Class I* wells currently exist within the state. The State has no authority over *Class I* wells.
- ⇒ *Class II Wells* are governed by the state and the Federal EPA, and have been in operation in California for over 50 years. Currently, over 25,000 *Class II* injection wells are operating in the state. *Class II* wells are used to increase oil recovery and to safely dispose of the salt and fresh water produced with oil and natural gas. In California, all *Class II* injection wells are regulated by the *Department of Conservation, Division of Oil, Gas, and Geothermal Resource*s, under provisions of the state Public Resources Code and the Federal Safe Drinking Water Act.

  California state regulations are more stringent than federal regulations as they require the following:
  - *Class II* wells in California need to be constructed to the same stringent specifications as Class I wells.
  - Reporting is required on an annual basis rather than every three to five years.
  - The State of California requires annual radioactive tracer testing.

In addition to the UIC requirements, the *California Environmental Quality Act* (CEQA) may be an impediment to future development of CO_2 storage projects in the State. Any proposed projects must be permitted through CEQA, which has a long history of delaying a number of large projects, such as pipelines and cogeneration power plants in California. In some cases, the CEQA review process has resulted in delays of as much as several years.

8.4.4.2 Oklahoma

The *Oklahoma Department of Environmental Quality* (DEQ) regulates *Class I* and *Class V* injection wells (Oklahoma Administrative Code (OAC) 252:652). The Oklahoma Corporation Commission (OCC) regulates *Class II* injection wells (*Title 165: Chapter 10*). Regulations in Oklahoma appear to mirror the Federal program with very few exceptions. Potentially within the state of Oklahoma, *Class I* injection well limitations could preclude more than half of the State based on geology alone, as *Class I* injection wells are required to be in bedrock formations, below drinking water aquifers with a confining layer between the injection point and the drinking water aquifers.

8.4.4.3 Ohio

The UIC Section of the Ohio Division of Drinking and Ground Waters is responsible for the regulation of Class I and Class V injection wells and for assuring that Class IV wells are plugged and abandoned in accordance with state law (*Chapter 3745-34 of the Ohio Administrative Code*). The UIC Program is established under the authority of Ohio Revised Code (ORC) Sections *ORC*

6111.043 and *ORC 6111.044*. The *Ohio Department of Natural Resources Division of Mineral Resources Management* regulates *Class II* and *III* UIC wells.

Owners and Operators of *Class I* injection wells are required to apply to the Ohio EPA for a permit for each well (OAC rule 3745-34-16). Permits are granted only after extensive data review followed by issuance of draft permits open to public comment. All Class I wells have strict siting, construction, operation and maintenance requirements designed to ensure the protection of drinking water supplies. Similar restrictions can be expected for the permitting of CO_2 injection wells.

The Ohio State UIC program is similar to the Federal UIC program, with the following exceptions:

⇒ The State permitting process is tailored to be facility specific. Class I facilities must provide more detailed information to the State about the nature of the injected material and operations producing waste.

⇒ Monitoring, such as mechanical integrity testing and tracer testing of permitted injection wells, is more stringent, and required on a more frequent basis.

⇒ Operating reports are required monthly as opposed to annually.

8.4.4.4 Texas

The TCEQ regulates and permits all *Class I* and *Class V* wells in the State (*Texas Administrative Code (TAC), TAC Title 30, Part 1, Chapter 331*). *The Railroad Commission of Texas* regulates all *Class II* wells (TAC, Title 16, Part 1, Chapters 1 through 20).

In Texas, CO_2 storage site selection among existing enhanced oil recovery operations will likely achieve widespread acceptance, since these communities and regulators are already familiar with energy production and drilling operations, and much of the necessary infrastructure and support services are in place.

In general, there are very few differences between the Texas rules and the Federal regulations.

8.4.5 Regulatory Gaps in Permitting for CO_2 Injection

- There is currently no definitive decision by the federal EPA or State regulatory agencies as to which class of injection wells are likely to be approved for CCS projects (*Class I, Class II*, or *Class V*);
- State UIC requirements may differ from Federal requirements and from State to State, depending on how each individual State has elected to enforce the UIC Programme controls. This means more rigorous approvals requirements under UIC are required in some States;
- Whilst existing pilot projects provide some guidance for the regulatory, commercial, and legal processes surrounding storage and injection, it is not clear whether the same requirements will apply to full-scale projects;

- Local communities may not support injection facility planning within their borders. Community activist groups have a history in certain areas throughout the US, of mobilizing local opposition to industrial development and/or project expansion. Federal and State governments need to address active monitoring requirements to provide safety assurance and hence encourage local governments to accept facilities.

8.4.6 *Permitting issues for CO_2 storage site stewardship*

Short term and long term stewardship of CO_2 storage sites includes activities such as monitoring, and closure and decommissioning planning to ensure site security and safety. To some extent, monitoring requirements exist throughout the various stages of a CCS project cycle in the USA via the requirements laid down by UIC Programme controls and natural gas storage regulations (IOGCC, 2005), although there remains significant uncertainty as to how long-term stewardship of CO_2 storage might be handled (see IOGCC, 2005).

8.4.6.1 *Summary of key issues*

- Monitoring and verification requirements already exist for CO_2 transport pipelines and UIC injection wells, and are directly applicable to CCS projects.
- Additional requirements may include near surface air monitoring and shallow soil gas monitoring.
- The US DOE anticipates the creation and implementation of a monitoring and verification program for CCS within the next three to five years.

8.4.6.2 *Monitoring of injection sites*

Under the UIC program, monitoring requirements for injection wells are summarized in *40 CFR 146*. Specific requirements for relevant classes of injection wells are described below.

Class I – Non-Hazardous

For all *Class I* wells the following monitoring requirements apply (*40 CFR 146.13*):

⇒ The analysis of injected fluids on a regular frequency to adequately characterize the nature and composition of the injected fluid.
⇒ Continuous monitoring of injection pressure, flow rate and volume, and annulus pressure.
⇒ Demonstration of mechanical integrity once every five years.
⇒ Development of a monitoring plan within ¼ mile of the injection well.
⇒ Annual monitoring of pressure build-up in the injection zone.

Additional monitoring requirements, depending on the particular characterisation of the site, may include:

⇒ Continuous monitoring of pressure changes in the first aquifer overlying the confining zone.
⇒ Quarterly sampling of the first aquifer overlying the confining zone for constituents consistent with the nature and composition of the injection fluid.
⇒ The use of geophysical techniques to determine the position of the waste front within the injection zone.
⇒ Periodic monitoring of groundwater quality in the shallow aquifer overlying the injection zone.

Class II – EOR and Coal Bed Methane Extraction (CBME)

For all Class II wells the following monitoring requirements apply (*40 CFR 146.23*):

⇒ The analysis of injected fluids on a regular frequency to adequately characterize the nature and composition of the injected fluid.
⇒ Continuous monitoring of injection pressure, flow rate and volume, and annulus pressure at the following frequencies:
  - o Weekly for produced fluid disposal operations,
  - o Monthly for EOR,
  - o Daily during injection for withdrawal of stored hydrocarbons.
⇒ Demonstration of mechanical integrity once every five years.
⇒ EOR may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring (i.e. by monitoring the entire array of wells via a centralized monitoring station).

Class V – Experimental Technology Wells

Monitoring requirements for *Class V* injection wells are not described under the applicable regulation (*40 CFR 146.51*). However, specific monitoring requirements may be established on a project-by-project basis. In general, monitoring requirements are expected to be very similar to Class I injection wells.

Well Decommissioning requirements for Class I, II, and V Wells

Under *40 CFR 146.10* UIC wells must be abandoned/decommissioned following use. The abandonment procedures appear to be consistent with established well abandonment procedures in oil and gas exploration and production. Most importantly the following requirements must be met:

⇒ Wells must be plugged with cement in a manner that does not allow for the movement of fluids between aquifers.
⇒ Wells must be plugged in a manner that prevents the movement of contaminants into a drinking water supply.

8.4.7 *Conclusions on CO_2 storage site permitting in the USA*

Based on the current regulatory regime in place for underground injection of liquid materials, the following conclusions regarding CO_2 storage site permitting in the US can be drawn:

- ⇒ No standard exists for defining an unacceptable risk of failure for a CCS project.
- ⇒ No standard exists for defining an unacceptable release to the environment; no standards exist for monitoring for potential release of CO_2.
- ⇒ A process hazard analysis for CCS does not appear to exist at this time.
- ⇒ There are no specific performance standards for CCS wells and storage reservoirs. By way of example, radioactive waste disposal sites in deep geologic formations in the US have well-established performance standards that require that an agency demonstrate that these standards have been met prior to permitting and actual disposal.
- ⇒ There are currently no well abandonment/closure standards and permit stipulations specifically designed for CCS.
- ⇒ Any underground injection activities in the US in the near term will undergo permitting as established under the *EPA UIC Program. UIC Class I*, *Class II*, and *Class V* wells apply to CCS activities.
- ⇒ CO_2 injection under pilot programs for CCS is currently permitted as *Class V*. CO_2 injection wells for the purposes of EOR are permitted as *Class II*.
- ⇒ Injection wells for the purposes of CCS for climate change mitigation will most likely be permitted as *Class I* Non-Hazardous wells. Permitting *Class I* injection wells will vary from State-to-State, as permitting under the UIC program is primarily the responsibility of the individual States.

8.5 *CONSIDERATIONS IN A CANADIAN CONTEXT*

8.5.1 *Overview*

There are several existing Provincial regulations related to the injection of natural gas and acid (sour) gas for subsurface storage. Some of these address CO_2 specifically while others are not as comprehensive.

In the large part this is driven by the economics of H_2S removal from acid gas produced in association with oil: Since surface desulphurization of acid gas using the Claus process is generally proving to be uneconomical, and the surface storage of the produced sulphur constitutes a liability, more operators in western Canada are turning to acid gas disposal by injection into deep geological formations (IOGCC, 2005).

Although the purpose of the acid-gas injection operations is to dispose of H_2S, significant quantities of CO_2 are co-injected because of the cost of CO_2 separation. Such acid gas injection operations represent a useful analogue to geological storage of CO_2. Currently acid gas injection occurs only in Alberta and north-eastern British Columbia.

8.5.2 *Approvals and Environmental Assessment*

8.5.2.1 *Overview*

Canada has Federal and Provincial environmental assessment and environmental protection requirements in place. Considering the nature of CO_2 injection and storage projects, an environmental assessment may be required prior to approval in Canada, although there is no explicit requirement in Federal or Provincial legislation with regard to CCS to date.

The following EIA regimes are in operation in Canada:

⇒ *Federal*: *Canadian Environmental Assessment Act* has jurisdiction over projects where there are concerns regarding potential trans-boundary effects between Provinces or where Federal lands/Federal authorities are involved.

⇒ *Alberta*: environmental assessments are covered under the *Alberta Environmental Protection and Assessment Act*.

⇒ *British Columbia*: environmental assessments are covered under the *BC Environmental Assessment Act*. There is no direct mention of CO_2 in either of these regulations.

⇒ *Saskatchewan*: environmental assessments are covered under the *Environmental Assessment Act* and the *Environmental Management and Protection Act*.

Under the relevant Acts, CO_2 could also be classified as a contaminant since it will be injected at levels exceeding natural background levels. Additionally, there is a requirement to identify a responsible party for any discharges to the environment.

8.5.3 *Provincial level Environmental Assessments and Approvals Processes*

Either the Federal Environmental Assessment (EA) process or a Provincial approval process, or both, may be applicable to all aspects of CCS operations. In the case of a project that is subject to Federal and Provincial requirements for EAs, one does not supersede the other and all legislative requirements must be met. However, cooperation agreements exist between individual Provinces and the Federal authorities, which allow projects subject to both sets of regulations to perform only one EA. The Provinces of British Columbia, Alberta and Saskatchewan have such agreements.

8.5.3.1 Alberta

The *Environmental Assessment Regulation* under the *Alberta Environmental Protection and Enhancement Act* (AEPEA) lays down the requirements for EAs in Alberta. The *Environmental Assessment (Mandatory and Exempted Activities) Regulation* does not address CO_2 storage projects directly, but under *Part II* of the AEPEA the Directory can recommend an environmental assessment be completed for any proposed activity whose potential impacts require further assessment. The four stages of the Environmental Assessment Process (EAP) are:

⇒ Stage 1 – Initial Review
⇒ Stage 2 – Screening
⇒ Stage 3 – Preparation of an Environmental Impact Assessment Report
⇒ Stage 4 – Final Review

The proponent of a project requiring an EA must publish a notice stating where and how copies of the completed EA report or summary can be obtained for public review. The EA report must include the results of all public consultations or upcoming plans for public consultation. The Director keeps a public registry of all information pertaining to the EA process.

Alberta - Other Approvals

Under the *Alberta Environmental Protection and Enhancement Act*, approvals are required for designated activities which, according to the *Alberta Activities Designation Regulation*, includes deepwell injection of waste intended as a final resting place in the definition of disposal. The definition of waste is any solid or liquid material that is not recyclable, destined for treatment or disposal. The construction or operation of a facility where more than 10 tonnes per month of waste is treated is a designated activity.

The AEPEA states that activities covered by Codes of Practice cannot be commenced or continued unless done so in accordance with the Code of Practice. A Code of Practice currently exists for compressor and pumping stations and sweet gas facilities.

8.5.3.2 British Columbia

The *BC Environmental Management Act*, *Section 78*, gives the minister the power to require an environmental impact assessment (EIA) if the minister considers a proposed project to have a detrimental impact on the environment and insufficient information is available to assess the environmental impact. When required, an EIA must assess the detrimental and beneficial impacts on water and air quality, land and water use, aquatic and terrestrial ecology.

Under the *Environmental Assessment Act*, a minister issues an environmental assessment certificate with restrictions when a reviewable project (as defined by the *Reviewable Projects Regulation*) application, including the environmental assessment, is deemed acceptable. Reviewable projects are defined by the type of project and further divided into subcategories, for example, 'waste disposal' activities qualify as reviewable projects, and could potentially apply to CO_2 storage. Also, under the *Reviewable Projects Regulation*, contaminants are assigned weightings for the purposes of calculating waste discharge from a certain project type, although it is interesting to note that whilst CO_2 is currently listed as a contaminant, it is assigned a weighting of zero.

8.5.3.3 Saskatchewan

The *Saskatchewan Environmental Assessment Act* broadly defines which projects require Ministerial Approval. All aspects of a CCS projects (capture, transportation and storage) may be required to complete an EA prior to commencing within the Province of Saskatchewan. The Act also states that an EIA shall be conducted in accordance with the regulations, however no regulations currently exist under this Act. Proponents are required to prepare and submit an environmental impact statement that can be made available for public inspection and review for at least 30 days on the *Saskatchewan Environment's* - the Province's environmental protection authority - website. The minister may also choose to conduct a public information meeting regarding the proposed development. Upon granting approval to proceed, the Minister may impose terms and conditions.

8.5.3.4 Reporting

The Federal environmental protection authority (Environment Canada) operates the *National Pollutant Release Inventory* (NPRI) under the *Canadian Environmental Protection Act* (CEPEA). As the NPRI does not include the reporting of greenhouse gases, a separate reporting requirement is regulated by Statistics Canada in conjunction with Environment Canada. In 2004 greenhouse gas emissions were collected from facilities that emitted 100 kilotonnes or more of CO_2 or equivalent emissions.

8.5.4 Injection

8.5.4.1 Federal

There are currently no federal regulations specifically covering CO_2 injection in Canada. A number of relevant Provincial Acts and Regulations do apply to CCS either directly, or via acid gas injection rules, as outlined below.

8.5.4.2 Alberta

In Alberta, the Alberta Energy and Utilities Board (AEUB) regulates injection of acid (sour) gas (including CO_2) into geological formations. For acid gas disposal, specific requirements are listed in the *AEUB Guide 65*: *Resources Applications for Conventional & Gas Reservoirs, Calgary AB, 2000.*

Acid-gas injection wells are classified as *Class III* disposal wells, unless the acid gas is dissolved in produced water prior to injection, in which case the well is designated as either *Class Ib* or *Class II*, depending on the produced-water designation (*AEUB Guide 51: Injection and Disposal Wells*).

AEUB Class III injection wells are used for the injection of hydrocarbons, or inert or other gasses for the purpose of storage in or enhanced hydrocarbon recovery from a reservoir matrix and includes but is not restricted to:

⇒ Solvents or other hydrocarbon products used for enhanced recovery operations;
⇒ Sweet gas used for gas storage operations;
⇒ CO_2, N_2, O_2, air or other gasses used for storage or enhanced recovery;
⇒ Sour or acid gases for disposal, storage or cycling operations.

In all classes the location and purpose of the well must first be approved as a part of a specific scheme approval as required by the Alberta *Oil and Gas Conservation Act* (OGCA) and the *Oil and Gas Conservation Regulations* (OGCR), or the *Oil Sands Conservation Act* (OSCA).

A number of specific criteria are laid down in the regulations (*Box 8.7*).

Box 8.7 Alberta acid gas injection well regulation requirements

Hydrocarbon contamination: For all classes of injection wells, potential hydrocarbon-bearing zones, in addition to injection or disposal zone, must be isolated by cement. Where thermal operations are conducted or anticipated, thermal cement must be used. If the production casing is not cemented to the surface or cement returns to the surface are not obtained and maintained during setting, then a cement top-locating log must be run.

Well log reports: All required logs shall be submitted to the *Energy Resources Conservation Board* (ERCB), accompanied by a detailed interpretation of the log against its specific objective, for approval prior to commencement of regular injection/disposal operations. A completed well summary for injection or disposal form as well as a *Well Completion Schematic* shall be submitted as part of any application for disposal or injection. A full-length casing inspection log must be run on any existing well being converted to injection or disposal service. An initial pressure test of the casing or tubing/casing annulus to minimum pressure of 7000kPa for 15 minutes shall be conducted prior to commencement of injection or disposal operations. Annual packing isolation test to a minimum surface pressure of 1400kPa for 15 minutes. For Class III injection wells, wellhead pressure will be limited to the lesser of 90 per cent of the formation fracture pressure, or the pressure at which the hydraulic isolation logging was conducted.

The formation fracture pressure as referenced above may be determined by step-rate injectivity tests, in situ stress test, mini frac or reliable offset or regional fracture/injectivity data. Approval to inject above the fracture pressure may require an assessment of fracture containment potential and analysis of the effects of such an injection on useable groundwater and hydrocarbon recovery.

Some discretion in determining wellhead injection pressure may be necessary in high-pressure solvent injection where logging pressure may be restricted by the effectiveness of wireline pressure control equipment, or where cement integrity logs are submitted as evidence of hydraulic isolation.

Wells included in an EOR or gas storage scheme may also be subject to further wellhead pressure limitations as specified in their scheme approval.

An application for disposal would likely be approved if the AEUB is satisfied that:

- ⇒ Disposal will not impact hydrocarbon recovery,
- ⇒ The disposal fluid will be confined to the injection formation,
- ⇒ Offset owners within 1.6 km of the disposal well(s) have been consulted and have no objections or concerns to the disposal scheme, and
- ⇒ The applicant has the right to dispose into the requested formation.

Figure 8.3 outlines the overall oil and gas resources applications process, and *Figure 8.4* shows the oil and gas resources applications evaluation process under the AEUB guides.

Figure 8.3 Oil and gas resources application process - Alberta

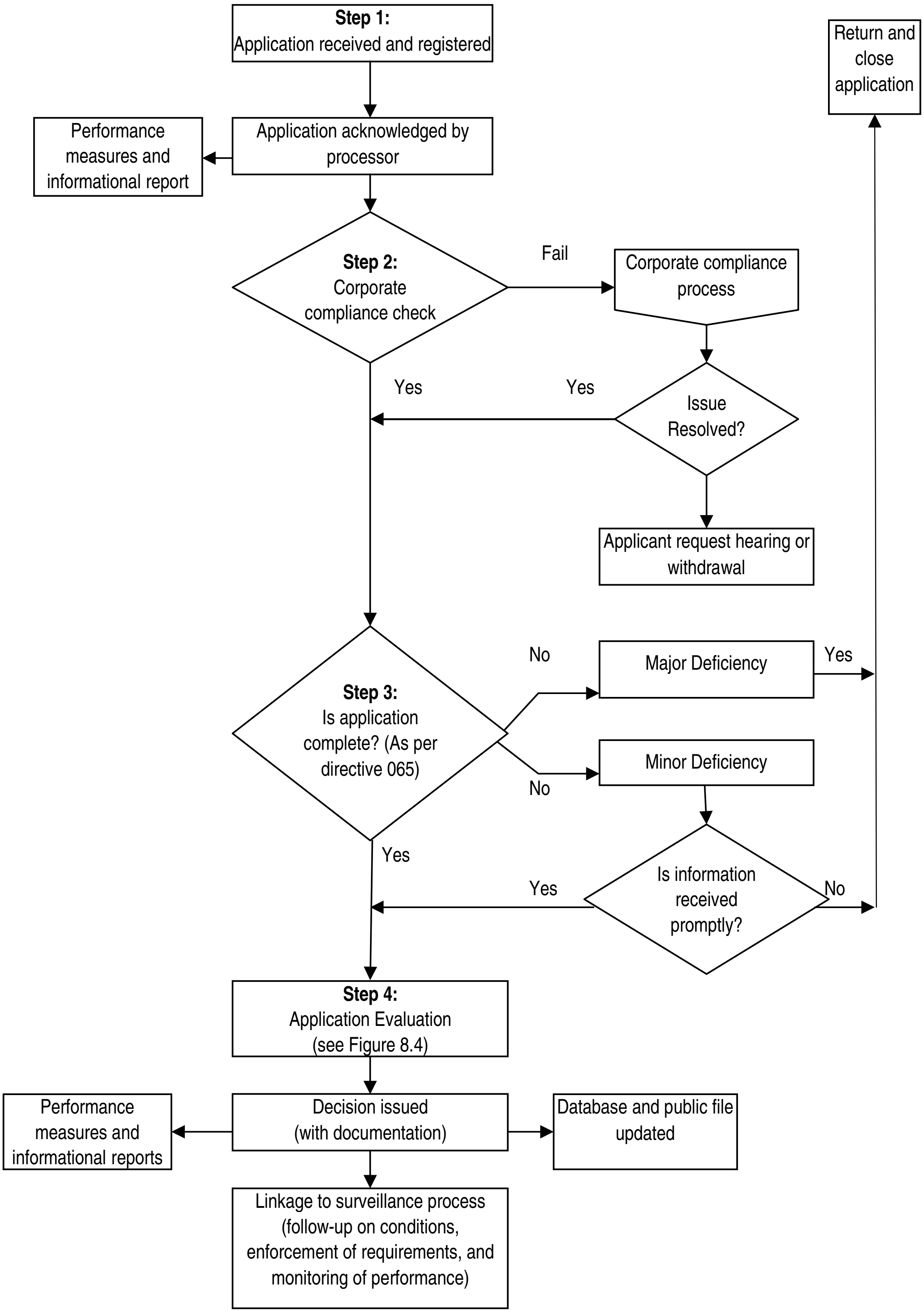
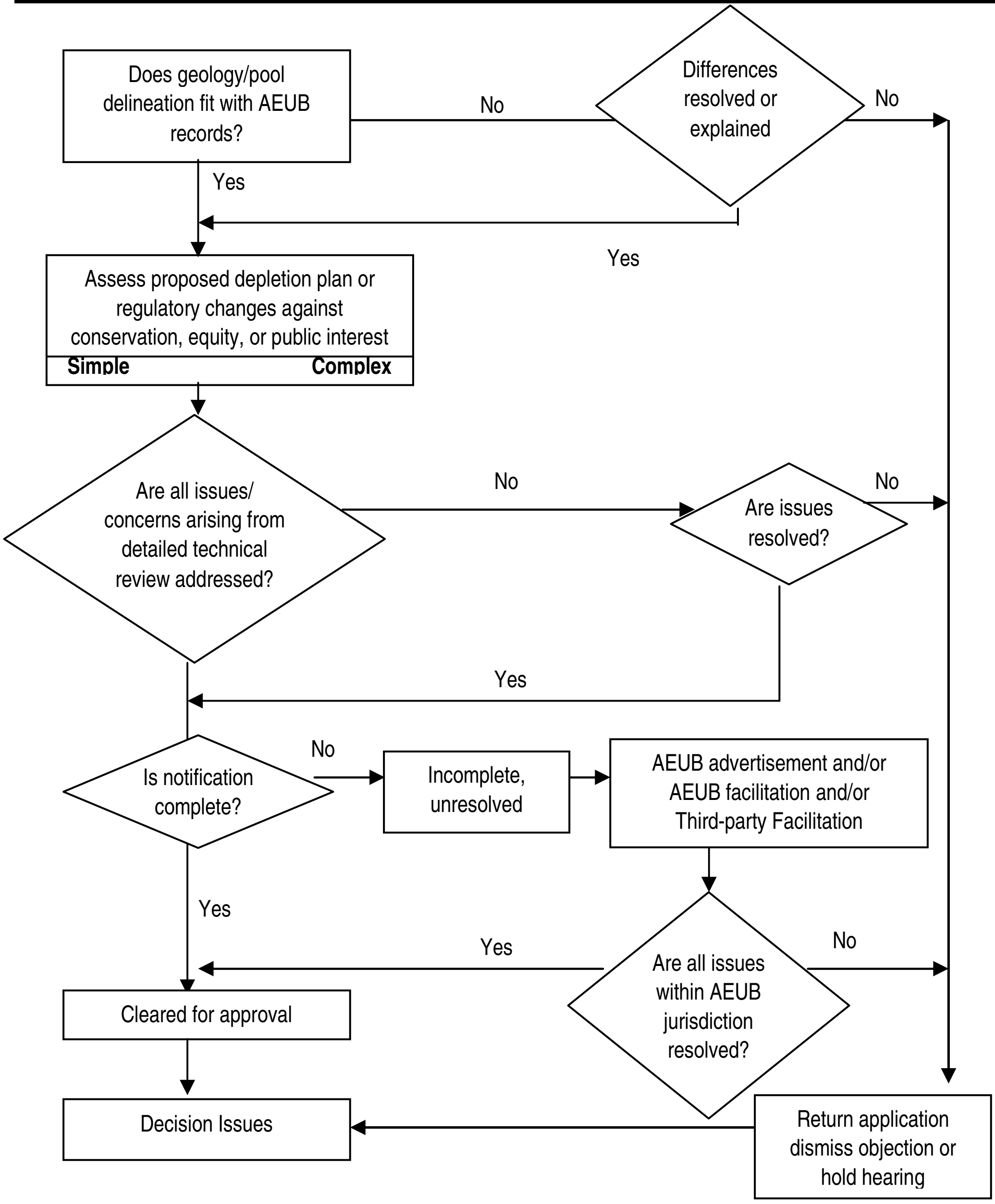


Figure 8.4 Resources application evaluation process - Alberta



8.5.4.3 *British Columbia*

Under the *BC Petroleum and Natural Gas Act*, owners or operators of equipment or facilities may discharge from the equipment or facility acid gas (including hydrogen sulphide and carbon dioxide) by means of underground injection provided that the discharge is approved by the *Minister of Employment and Investment* under the scheme approval process. This takes a similar form as outlined for Alberta, albeit with certain Province-specific elements and approvals.

8.5.4.4 *Saskatchewan*

In southeast Saskatchewan, CO_2 has been injected and stored since 2000 in the 50-year-old Weyburn oilfield, on the basis of using the anthropogenic-sourced CO_2 for the purpose of EOR in a mature field, and storing CO_2 that would otherwise be vented from the North Dakota coal gasification plant (see *Box 8.5*).

Under the Saskatchewan *Oil and Gas Conservation Act*, requirements are laid down for the minister of Energy and Mines to potentially make orders approving plans for increasing or improving oil or gas recovery or operations, including plans for introducing any substance into the producing formation and disposing of oil-and-gas wastes or non-oil-and-gas wastes in subsurface formations. Under this regime, the minister may include an order pursuant to any terms and conditions that the minister considers advisable, meaning that CO_2 injection may not proceed prior ministerial approval. Essentially, this allows for the regulatory approvals process to set down specific requirements for any proposed project on a case-by-case basis within the Province.

Also, under the Saskatchewan *Oil and Gas Conservation Regulations*, a plan for the disposal of oil-and-gas wastes or non-oil-and-gas wastes into subsurface formations must be accompanied by the written consent of all owners and all fee simple mineral owners, other than the Crown, that in the opinion of the minister " *may reasonably be adversely affected by the disposal; and any other information or material that the minister may require*". As such, without prior written approval, operators cannot dispose of oil-and-gas wastes via injection, including but not limited to drilling fluids and waste oil or refuse from tanks or wells. Consequently, it is likely that CO_2 storage operations would require written approval in Saskatchewan.

8.5.5 **Storage**

8.5.5.1 *Federal*

There are currently no Federal or Provincial regulations addressing the specific requirements for CO_2 storage. However Canada does have a *National Standard of Canada for Reservoir Storage* (*CSA Standard Z341*), which sets out the minimum requirements for the design, construction, operation, maintenance, abandonment, and safety of hydrocarbon storage in underground formations and associated equipment. This covers, but is not limited to storage wellhead and christmas tree assemblies; wells and subsurface equipment; and safety equipment, including monitoring, control, and emergency shutdown systems.

CSA Standard Z341 does not apply in cases where underground storage of hydrocarbons containing hydrogen sulphide in concentrations greater than 10 mol/kmol are planned.

8.5.5.2 *Alberta*

Alberta CO_2 Project Royalty Credit Regulation defines CO_2 as a gaseous mixture consisting mainly of carbon dioxide. The same regulation defines a CO_2 project as a scheme approved under the *Oil and Gas Conservation Act* for enhanced recovery of petroleum or natural gas from any underground formation through the injection of CO_2 into the formation. The Minister may, on application by the operator, approve a CO_2 project for the purposes of the Regulation if the Minister is satisfied that the project will employ an approved process, and that approving the project for the purposes of the Regulation is in the public interest. This could consist of assurances that the project meets *CSA Standard Z341*.

8.5.5.3 *British Columbia*

Under the *BC Petroleum and Natural Gas Act*, exploration for storage reservoirs may not proceed unless the Assistant Deputy Minister of the Energy Resources Division, Ministry of Energy and Mines, approves a license from the applicant. The division Assistant Deputy Minister may grant a licence to a person to explore for a storage reservoir, for a period of time he or she determines and subject to conditions he or she determines, or the division head may refuse to grant the licence.

On the recommendation of the Ministry of Energy and Mines, the Lieutenant Governor in Council may by regulation designate land as a storage area. Ninety days after designation of land as a storage area, a right, title and interest in a storage reservoir in or under the storage area is vested in the government. The holder of a petroleum or natural gas permit, drilling licence or lease or an exploration licence may apply to the Ministry of Energy and Mines for a lease of a storage reservoir that is owned by the government.

Furthermore, any proposal also requires approval from the Oil and Gas Commission. The Commission may grant a licence to a person to develop or use a storage reservoir for the storage of petroleum or natural gas, grant the licence for a period of time he or she determines and subject to conditions he or she determines, or the commission may refuse to grant the licence. The commission may require that the underground storage project be designed, constructed, operated and abandoned in accordance with all or portions of the *CSA Standard Z341*.

Under the *BC Petroleum and Natural Gas Storage Reservoir Regulation*, an exploration licence must be applied for to explore for a storage reservoir; the granting of a lease of a storage reservoir; and the granting of a storage licence for the development or use of a storage reservoir for the storage of petroleum or natural gas. An application for a licence for a lease made under the *Petroleum and Natural Gas Act* must include the information specified in the *British Columbia Oil and Gas Handbook*. This handbook is designed to assist the petroleum industry in planning and conducting operations in British Columbia and in adhering to its guiding principles. The handbook consolidates a variety of legislative requirements, regulation, procedures and guidelines, and provides a starting point from which the project proponent can plan and undertake activities, acquire additional reference material or contact government personnel and industry associations for further assistance.

8.5.5.4 Saskatchewan

Saskatchewan Industry and Resources has several guidelines under the Oil and Gas section that may be applicable to CO_2 projects, including:

- ⇒ PNG Guideline 20 - Application for a Gas Storage Project.
- ⇒ PNG Guideline 12 - Application for an EOR Project other than a Water flood.
- ⇒ PNG Guideline 21 - Application for a Pipeline Licence.

8.5.6 Monitoring

Currently there are no federal regulatory or permitting requirements specifically addressing the monitoring of CO_2 during and following injection into a geological formation.

8.5.6.1 Alberta

Alberta Oil and Gas Conservation Regulations require that where gas, air, water or other substance is injected through a well to an underground formation, it must be continuously measured by a method satisfactory to the Alberta Energy Resources Conservation Board.

8.5.6.2 British Columbia

Currently there are no Provincial regulatory or permitting requirements in British Columbia specifically addressing the monitoring of CO_2 storage projects.

8.5.6.3 Saskatchewan

The Saskatchewan *Oil and Gas Conservation Regulations* require that all waste disposal wells and pressure maintenance wells are to be inspected by the department at least once every two years, or as directed by the minister, to ensure that there are no production casing, tubing or packer failures; and the tubing-production casing annulus is filled with a satisfactory corrosion inhibiting fluid.

It also requires that any person whom produces, sells, purchases, acquires, stores, transports, refines or processes oil or gas shall keep and maintain complete and accurate records in Saskatchewan of the quantities of the oil or gas.

If water or gas is injected or disposed of into a well, the owner is required to keep a daily record of the well on an approved form showing the gas injected or disposed of into the well; the source from which the gas was obtained; the particulars of any treatment to which the gas has been subjected; and the pressure used in the injection of the fluid.

8.5.7 Abandonment of Wells

Currently there are no Federal and only limited Provincial regulatory or permitting requirements specifically related to the abandonment of wells used for CO_2 injection. The long-term responsibility for the abandoned well is also not addressed under current legislation.

8.5.7.1 Alberta

Well abandonment is covered under the *Alberta Oil and Gas Conservation Regulations* and *Guide G-20 'Well Abandonment'*. Abandonment of a well does not relieve the operator of the well from responsibilities associated with the control or further abandonment of the well, suggesting perpetual liability for the well.

8.5.7.2 British Columbia

Under the *BC Petroleum and Natural Gas Act*, a person can be considered not to have abandoned a well, test hole or production facility until the BC Oil and Gas Commission issues, on application, a certificate of restoration respecting the well, test hole or production facility. By issuing a certificate of restoration, the Commission may certify that it is satisfied, that a well, test hole or production facility has been abandoned in accordance with the regulations.

Under the *BC Drilling and Production Regulation*, no wells may be left unplugged or uncased after they are no longer in use. All permeable formations must also be isolated using cement.

8.5.7.3 Saskatchewan

The *Saskatchewan Oil and Gas Conservation Regulations* indicate that no well shall be left unplugged or uncased when no longer in use. They also require that prior to the completion or abandonment of a well, the operator must have the following logs taken unless otherwise approved:

- ⇒ An approved resistivity log or standard electric log, excluding contact logs, from surface casing shoe to total depth;
- ⇒ An approved radioactivity log, including both natural and induced radioactivity or an approved porosity curve, commencing at a distance sufficiently above the top of the Paleozoic Erathem to give an accurate shale line, to the total depth if the well penetrates more than 15 metres into the Paleozoic Erathem.

8.5.8 *Long Term Responsibility*

The current Provincial legislation addresses short-term responsibility only. There are no provisions for long-term responsibility for CO_2 stored within a geological formation.

8.5.9 *Summary and Overview of Permitting Considerations for CO_2 Injection and Storage in Canada*

Whilst elements of the existing Provincial regulatory frameworks for the oil and gas industry address some of the issues associated with CO_2 injection and storage in Canada, a significant gap exists with regards to long-term liability. As such, the liability issue is likely to require further consideration by Federal or Provincial regulators (or both) going forward.

8.6 *CONSIDERATIONS IN AN AUSTRALIAN CONTEXT*

8.6.1 *Introduction*

CO_2 injection and storage is not currently considered in Australian regulations.

However, Australia can be considered to be at an advanced stage relative to other jurisdictions, principally through two key developments:

i). Passing of the *Barrow Island Act 2003* by the Western Australian government, which allows the re-injection of CO_2 into a saline aquifer off of Barrow Island, and;
ii). The development of the Commonwealth *Draft Guiding Regulatory Framework for Carbon Dioxide Geosequestration*, which outlines the underlying principles against which a regulatory regime of CO_2 capture and storage could be developed.

The *Barrow Island Act 2003* has been developed specifically for the re-injection of permeate gas (mainly CO_2) from the Gorgon gas field development (*Box 8.7*). The Draft regulatory principles form part of a wider range of ongoing activities that aim to promote the appropriate technical, political and regulatory environments for developing CO_2 geosequestration.

The Draft Regulatory principles for CCS are presented below (*Box 8.7*).

In order to outline how the Australian storage site permitting regime is evolving, the proceeding Sections present the assessment and approvals process undertaken for the Gorgon project. This provides a useful example of a possible process for storage site selection, operation and decommissioning.

In addition, the Australian oil and gas offshore regulations are presented as an example of regulation that draws together both Commonwealth and State requirements.

Box 8.8 *Consultation Regulation Impact Statement for the 'Draft Guiding Regulatory Framework for Carbon Dioxide Geosequestration'*

The draft framework states that the objective of government is to:

'introduce a regulatory framework within which industry can develop an emerging carbon capture and storage technological process. The framework needs to be transparent, predictable and practical providing community confidence and investor certainty. The purpose of the framework will be to improve economic efficiency and certainty in environmental, health and safety management wherever possible. The framework should provide for the development of regulation which will allow consistency in assessment and approval processes for regulators in cross-jurisdictional projects in Australia. The proposed framework does not explicitly increase the economic incentive to undertake geosequestration (carbon capture and storage)'.

Seven key issues were identified as fundamental to the successful implementation of a carbon capture and storage framework, they were;

- Access and property rights
- Long term responsibilities
- Environmental Protection
- Authorisation and compliance
- Monitoring and verification
- Transportation
- Financial issues

Each of these issues were analysed using three options; (1) Rely on market – no regulation, (2) Self regulation, and (3) Government regulation.

In relation to environmental protection, the recommendation of the draft framework is that explicit government regulation would best achieve the desired objectives and that;

'Existing regulation could generally be applied to carbon dioxide geosequestration (carbon capture and storage) activities or could be slightly amended at minimal cost to specifically apply to carbon dioxide geosequestration (carbon capture and storage)'.

The final recommendation of the Regulation Impact Statement is that government regulation is the preferred option. Within the final recommendation the document states that:

> *'Existing oil and gas regulations available in the Commonwealth, states and territories provide an adequate starting point for developing a framework. In view of the long-term storage requirement for carbon dioxide geosequestration (carbon capture and storage) however, specific regulations may need to be developed.*
>
> *It is therefore recommended that government regulation (a combination of Commonwealth, state and Territory legislation and of new and existing regulation) be used to manage the capture, transport, storage and post-closure phases of carbon dioxide geosequestration (carbon capture and storage).'*

On the basis of the recommendations presented in the Regulation Impact Statement it is possible that CCS projects would be regulated in a manner similar to the existing oil and gas regulations within Australia [(1)]. In the case of the Gorgon project (refer to *Box 8.8*) the existing Western Australian

(1) This is a similar conclusion as drawn by the IOGCC, 2005.

legislation has been amended to allow for the proposed pipeline transportation and underground storage of CO_2 using the existing oil and gas regulations. It is important to note that with the exception of Commonwealth waters, oil and gas regulations are specific to each State or Territory.

Box 8.8 *Case Study - Gorgon Project – Barrow Island Act 2003*

The Gorgon project is a proposed LNG development that has extensive proven hydrocarbon gas reserves. Carbon dioxide (CO_2) comprises approximately 14% of the raw gas reserve. The project intends to separate the CO_2 from the raw gas and inject the pure CO_2 gas stream into a deep, saline, geological formation below Barrow Island. It is estimated that the project could include the re-injection of 2 million to 3 million tons of CO_2 per year, subject to ongoing technical feasibility studies.

The government approvals process granted the Gorgon project approval "in principle" in September 2003. An environmental assessment and approvals process under the Commonwealth EPBC Act and relevant West Australian Act, started in November 2003, is anticipated to lead to a decision on Environmental approval late in 2005. In the absence of specific legislation, the Western Australian Government viewed that an environmental assessment would be insufficient because it would not account for the social and economic considerations.

In order to reduce regulatory uncertainty, the Western Australian Government amended the existing petroleum regulations to clarify the status of CO_2 transport and storage through the Barrow Island Act 2003.

The preface to the Barrow Island Act 2003 identifies part of its objective as:

- '*to make provisions as to the conveyance and underground disposal of carbon dioxide recovered during gas processing on Barrow Island'.*

Part 4 of the *Barrow Island Act 2003* – Conveyance and underground disposal of carbon dioxide, states that:

- *'The provisions of the Petroleum Pipelines Act 1969 apply as if there were included in the definition of 'petroleum' … (in) that Act a reference to carbon dioxide.'*
- *' … the definition (of 'pipeline' in the Petroleum Pipelines Act 1969) … is to be treated as including a pipeline for the conveyance of carbon dioxide to a place on Barrow Island for the purpose of disposing of the carbon dioxide in an underground reservoir or other subsurface formation.*

The *Barrow Island Act 2003* details the required information to accompany an application for the disposal of carbon dioxide underground:

- The position, size, capacity and geological structure of the underground reservoir or subsurface formations;
- The rate of disposal and the volume of CO_2;
- The CO_2 composition and disposal duration;
- Injection and disposal methods;
- The capability of the reservoir to confine the CO_2; and
- Any other technical advice and data considered necessary.

8.6.2 *Petroleum (Submerged Lands) Act 1967*

The *Petroleum (Submerged Lands) Act 1967* does not cover CCS. This act and associated regulations, present a possible analogous institutional framework for carbon capture and storage in that they provide a mechanism for a consistent regulatory environment for offshore oil and gas developments in Australia.

There is an agreement between the Commonwealth and all States and the Northern Territory to maintain, as far as practicable, common principles, rules and practices in the regulation of exploration and exploitation of petroleum resources in both State and Commonwealth territorial waters. It is envisaged that this framework could be applied to offshore CO_2 transport and storage. If existing oil and gas regulation is to be used as the basis for regulation of CCS within Australia, this will require each State to amend existing oil and gas regulation.

If a new regulatory framework was developed solely for carbon capture and storage the *Petroleum (Submerged Lands) Act 1967* presents a framework for agreement of environmental and other regulations between the State, Territory and Commonwealth Governments that could be applied Australia wide to both onshore and offshore carbon capture and storage projects.

The most relevant regulations associated with the *Petroleum Act 1962* are the *Petroleum (Submerged Lands) (Management of Environment) Regulations 1999*, other potentially relevant regulations include the *Management of Well Operations 2004,* and *Pipelines 2001*.

The *Petroleum (Submerged Lands) (Management of Environment) Regulations 1999* under the *Petroleum (Submerged Lands) Act 1967* apply to offshore oil and gas approvals in Commonwealth territorial waters. The objective of these regulations is to ensure;

> *'any petroleum activity in an adjacent area is carried out in a way that is consistent with the principles of ecological sustainable development, in accordance with environmental performance objectives and standards as well as measurement criteria for determining whether the objectives and standards are met.'*

These regulations cover any petroleum activity, which includes;

- seismic or other surveys;
- drilling;
- construction and installation of a facility;
- operation of a facility;
- significant modification of a pipeline;
- decommissioning, dismantling or removing a pipeline;
- storage, processing or transport of petroleum;
- any other operations or works for which a petroleum instrument, other authority or consent is required under the Act or the regulations.

For these activities the regulations define the requirement and content of an environmental plan to be submitted for a petroleum activity. The regulations also specify the penalties for non-compliance and the statutory requirements regarding incidents, reports and records.

8.6.3 Site planning phase - Gorgon Environmental Approval Process

Australia is currently the only country in the world that has made specific amendments to regulations in order to allow CO_2 injection and storage. These were made in response to the proposal for the development of the Gorgon gas field off of Western Australia; a field which has a high CO_2 content (~14%).

In 2002, the government of Western Australia determined that a strategic level evaluation of the proposed Gorgon project was required. The evaluation consisted of an Environmental, Social and Economic (ESE) Review of the Gorgon project, prepared by the operator of the Gorgon gas field, Chevron.

The ESE Review was conducted against a detailed scope established in accordance with Western Australia Government guidelines and endorsed by relevant Government agencies.

The ESE Review was submitted for State government consideration in February 2003. The government sought advice on environmental matters from the *WA Environmental Protection Authority* (EPA) and *Conservation Commission of Western Australia*, in which management of the Barrow Island Nature Reserve is vested. Social, economic and strategic aspects of the plan were considered by the *WA Department of Industry and Resources*.

Each of these agencies submitted their recommendations to the WA Government, in the form of a number of Bulletins, in July 2003. These bulletins were released for a six-week public review period that closed in August 2003.

In September 2003 the Western Australian Government decided to grant in-principle approval for the restricted use of Barrow Island for the Gorgon project development. In-principle approval does not constitute or imply environmental acceptance of the proposal.

Subsequent to receiving in-principle approval the Gorgon project is now required to undertake detailed engineering, environmental (including an EIA) and other studies required under Western Australian and Commonwealth legislation.

The Gorgon project was referred to the WA EPA in November 2003. The WA EPA has determined the development should be subject to an *Environmental Review and Management Programme* (ERMP) under the *Environmental Protection Act 1986*. This is a comprehensive level of assessment applied to major projects.

The Gorgon project was referred to the Commonwealth Minister for the Environment and Heritage in November 2003 for consideration of whether or not approval was required under the *Environmental Protection and Biodiversity Conservation Act 1999.* The Minister has determined that the proposal requires

Commonwealth environmental approval due to the following matters of national environmental significance;

- Listed threatened species and communities.
- Listed migratory species.
- Commonwealth marine environment.

The determination is that the Gorgon project must be assessed through the preparation of an Environmental Impact Statement (a Commonwealth-level EIA procedure). The Commonwealth and State environmental assessment processes have been co-ordinated and the preparation of draft joint environmental scoping document and guidelines, which outline the requirements of the joint EIS/ERMP were prepared; these were published for public comment in January 2004.

In April 2004 a joint Commonwealth (*EPBC Act)* and Western Australian *(EP Act)* '*Guidelines for an Environmental Impact Statement and Environmental Scoping Document for an Environmental Review and Management Programme*' was published.

The Gorgon project proponents are currently in the preparation of a single EIS/ERMP in accordance with the scoping document to satisfy the requirements of each jurisdiction.

Once the documents are complete and submitted, the following approval process will be undertaken;

- Public exhibition and review of the EIS/ERMP for a 10-week period.
- Preparation of an EIS Supplement by the proponent as an addendum or supplement once public comment has been received.
- Preparation of environmental assessment reports in each jurisdiction.
- Separate decisions by the Commonwealth Minister for the Environment and Heritage and the Western Australian Minister for Environment, both of whom will be in a position to determine whether the development could proceed, and if so, under what conditions.

The following sections detail some of the specific actions and proposals of the Gorgon project, as they relate to underground storage of CO_2.

8.6.4 Site Selection

Storage of reservoir CO_2 is considered a critical issue for the Gorgon project. The Gorgon joint venture evaluated 19 potential storage sites in the vicinity of the gas field. The sites were assessed based on the following criteria;

- capacity
- containment
- injectivity
- risk to assets.

The *Environmental, Social and Economic Review of the Gorgon Gas Development on Barrow Island*, prepared by Chevron Texaco, identifies the criteria for selection of a suitable CO_2 injection site;

⇒ The top of the reservoir for re-injection must be at least 800 m deep. At this depth the CO_2 will be in a dense supercritical state under normal geothermal conditions.
⇒ The reservoir system will provide containment of the CO_2.
⇒ The reservoir must have sufficient porosity and permeability to handle re-injection rates for the CO_2 volumes required. The Gorgon gas development requires a single site, or multiple sites near to each other, capable of taking approximately 250 million standard cubic feet per day and a total volume of approximately 2,500,000 million standard cubic feet or more. This would allow all the reservoir CO_2 produced from the proposed Gorgon development to be sequestered (from a 10 million tonnes per annum LNG facility producing for 30 years).
⇒ The reservoir must have the capacity to accept the volume of CO_2 being re-injected without build-up of pressures to conditions where safety or the integrity of the reservoir seals would be compromised.
⇒ The re-injection site should be close to the CO_2 source to minimise costs, transportation issues and increase overall 'greenhouse gas' efficiency.
⇒ The re-injection of CO_2 should not prevent the exploration and production of hydrocarbon resources from reservoirs within the area.

The scoping studies established that the massive sands of the Dupuy formation, located beneath Barrow Island have the capacity to store several times the volume of CO_2 anticipated from the Gorgon project. Some of the major factors that make the Dupuy saline reservoir the best option (as noted in the '*Environmental, Social and Economic Review of the Gorgon Gas Development on Barrow Island*') include:

⇒ The depth of the reservoir provides the most favourable technical conditions for re-injection.
⇒ Re-injection wells that penetrate into the Dupuy reservoir would allow access to other saline reservoirs as mitigation options.
⇒ The reservoir would be available for re-injection when gas production commences.
⇒ The location under a land mass and the existing oilfield provides increased geological data and monitoring opportunities to improve knowledge of the behaviour of re-injected CO_2.

As a result of detailed analysis, Barrow Island was confirmed as the only location that balanced the environmental, social and economic requirements of the Gorgon project.

8.6.5 *Site Development*

The preferred location for CO_2 injection is on the central eastern coast of Barrow Island in the general location of the proposed processing plant. The site was selected so as to maximise the migration distance from the major faults and to limit environmental disturbance to areas around the proposed gas processing plant.

The number of injection wells will be confirmed following further technical studies, scheduled for 2005. The wells are planned to be directionally drilled from the two or three surface locations to minimise the area of land required for the well sites, surface facilities, pipelines and access roads.

It is likely that the monitoring well (or wells) will be drilled from each cluster of injection wells to provide a sample point within the area of injection.

The Gorgon project has identified a work program to confirm the feasibility of reservoir CO_2 re-injection into the Dupuy saline reservoir. The work program is also designed to reduce uncertainties surrounding the storage component of the project to acceptable limits. The major items in the work program (as noted in the '*Environmental, Social and Economic Review of the Gorgon Gas Development on Barrow Island*') include:

⇒ detailed regional mapping to better define the extent and size of the Dupuy reservoir system;
⇒ down-hole static pressure measurements to confirm the hydraulic separation of the Dupuy saline reservoir from the formations above.
⇒ Use of existing reservoir core samples to study mineralogy and CO_2 dissolution effects;
⇒ consideration to obtaining extra core information to augment existing data sets;
⇒ detailed work to improve understanding of the sealing behaviour of the main Barrow Fault;
⇒ detailed subsurface computer modelling of CO_2 re-injection with presentation of the results to government and regulatory bodies;
⇒ identification of suitable surveillance and monitoring strategies to determine key early signs of potential injection or warnings of deterioration in re-inject ability or containment.

8.6.6 *Reservoir Filling*

The CO_2 will be transported by pipeline to several onshore injection wells into the Dupuy saline reservoir. To ensure efficient use of resources, re-injection would be implemented using a single train of injection equipment sized to handle the expected rate of reservoir CO_2 removed from the incoming gas stream. The system would be designed and operated in line with good oilfield practice for high-pressure injection. Limited venting would be required for the purposes of maintenance and re-injection equipment downtime or reservoir constraints. Re-injection of CO_2 will commence as soon as practicable after the processing facilities commissioning and start-up process.

A range of monitoring activities is planned as an integral component of the CO_2 injection proposal. These monitoring activities will comprise: routine observation and recording of injection rates and surface pressures at the injection wells. The main requirements for a monitoring program have been identified (in the '*Environmental, Social and Economic Review of the Gorgon Gas Development on Barrow Island*') as:

⇒ verification of net quantity of CO_2 stored.
⇒ interaction with dynamic reservoir simulations for history matching
⇒ validation of sequestration mechanism;
⇒ determination of efficiency such that that the available reservoir capacity has been utilised;
⇒ optimisation of the injection process (with respect to energy efficient operations);
⇒ demonstration that CO_2 is retained in formation in which it was injected.

In general, down-hole seismic and down-hole monitoring techniques will be preferred to minimise any environmental impacts.

8.6.7 Decommissioning

The *Barrow Island Act 2003* requires the proponents of the Gorgon project to submit to the Western Australian Minister on or before 31 December 2008 a detailed proposal (to the fullest extent reasonably practicable) regarding the closure plan including rehabilitation and long term management plan for injected carbon dioxide.

8.6.8 Conclusions on CO_2 storage site permitting in Australia

The Gorgon project, and the permitting of CO_2 storage via development of the *Barrow Island Act 2004*, represents an example of using existing oil and gas regulations to enable CO_2 storage. This example highlights the need for clear and effective regulation between the complex State and Federal environmental regulatory systems in Australia.

The Gorgon project documents completed to date, and the major items of the work programme committed to in the future provide an indication of the technical issues which need to be considered, evaluated and resolved in selecting, testing and monitoring a CO_2 storage site. Important lessons can be drawn from the procedures applied at Gorgon for use in the application of regulations in other jurisdictions.

9 CONCLUSIONS

This report has reviewed and analysed a diverse range of permitting issues that could apply to a CCS operation across the full chain of activities (*capture* > *transport* > *storage*), and in relation to all elements of a CCS operation life-cycle (*planning* > *operation* > *decommissioning* > *stewardship*). This analysis has covered permitting issues relevant to the oil & gas industry, the mining industry, aggregates and marine dredging, and other areas such as underground waste disposal in order to assess the appropriateness of existing regimes to a CCS operation, and to identify potential gaps that will need to filled.

Based on the analysis, a general picture has emerged over the appropriateness of existing environmental and health and safety permitting regimes to CCS operations. The picture presented is one where there is a distinct division between two elements of the CCS chain, namely:

- ⇒ *surface elements* including planning, construction and operating permits for a new power station with CO_2 capture (or retrofit), CO_2 pipelines, CO_2 injection facilities, storage site identification and selection activities including seismic surveys, exploratory drillings/boreholes etc. The analysis suggests that permitting regimes applicable to analogous industries and activities are well evolved and can largely accommodate these operations within these regimes with a few additions and adjustments to take account of the specifics of CCS operations, and;
- ⇒ *sub-surface elements* covering permits and licenses for development and operation, decommissioning and abandonment plans and permits for CO_2 storage sites, and accounting for issues of longer-term stewardship and liabilities following abandonment. Few precedents exist, and whilst some parts of existing regimes could be applicable, other considerations would require completely new permitting and licensing regulations to be developed.

These are considered in greater depth below:

9.1 PERMITTING SURFACE OPERATIONS

The surface elements of a CCS chain (capture>transport>injection) generally resemble many existing industrial activities, and as such are already well regulated under existing permitting regimes, at least within the OECD. As such, several broad conclusions can be drawn regarding permitting of the surface element of a CCS chain:

i) *No major additional regulatory developments will be required for above-ground installations and operations*: Any new-build development involving a CCS chain is likely to be a significant project in terms of the above-ground installations required, involving items such as a new power station (with capture plant), a CO_2 pipeline, and an injection wellhead facility. This type of development would already require preparation of a significant number of permits such as:

⇒ planning applications and consents
⇒ environmental statements,
⇒ environmental and social impact assessments,
⇒ health impact assessments, and
⇒ other regulatory and permitting considerations.

In addition, storage site surveying activities (such as seismic surveying, land access for undertaking surveys, drilling boreholes etc) will also be covered by existing permitting regulations, such as those applicable to oil & gas and mineral surveying and exploration. Therefore, consideration of the CCS element within these applications would be unlikely to present any major permitting constraints or significant new elements to consider within permitting regimes. This is consistent across all jurisdictions under study.

ii) *Energy penalty and thermal efficiency reduction*: The energy penalty associated with the operation of CO_2 capture on a power plant could have some impacts on the environmental permitting of the facility. This is a particular concern in an Australian context, where the Commonwealth *AGO Generator Efficiency Standards* (GES) could be breached because of the fall-off in efficiency. This is unlikely to have significant impacts for new build power plants with advanced boilers and turbine technologies or employing IGCC, but could impact on the re-permitting of retrofits to less efficient existing power plants. In the EU, the energy penalty could also create permitting issues under the EU IPPC and EIA Directives. IPPC permitting issues for new and/or retrofit CO_2 capture are less clear; the BREF guidelines for power sector permitting do not include clear guidance for regulators on the acceptability of the efficiency loss of a CO_2 capture plant. Moreover, CO_2 is not directly regulated in the same way as other gasses under EU regulations e.g. NO_x and SO_x, but is indirectly regulated via the EU ETS. Thus any trade off between the two may be difficult to justify in permit applications in the absence of clear BREF guidance. The integrated nature of IPPC permits may also mean that other trade offs will need to be carefully evaluated e.g. impacts on discharges to water, and the amounts and nature of hazardous and solid wastes generated. Under the EIA Directive, these issues will also be of concern in any permitting of a new power plant or major retrofit which triggers re-permitting under the Directive (*Box 6.7*). In the US, CO_2 is not a regulated air pollutant under the CAA; trade-offs between mitigating CO_2 emissions and increases in other pollutant emissions could be a problem. In Canada, permitting of CO_2 capture operations is likely to be treated on a case-by-case basis via the Code of Practice, although as Canada is a signatory to the Kyoto Protocol, and has an incentives program in place to promote uptake of CCS, it is likely to be well received by Canadian regulators. In most cases, clearer guidance for regulators on these issues, based on national environmental priorities e.g. local pollution concerns versus climate change concerns using some risk~benefit-based approach will likely be necessary.

iii) *Pipeline routing and permitted development rights*: Environmental, health and safety permitting considerations for major pipeline developments are well established in all jurisdictions. In the UK and Australia, permitted development rights for major pipeline constructions are long-established through the evolution of national water, sewerage, oil and gas infrastructures. The specific hazardous characteristics of CO_2 will need to be taken into consideration, however. Nonetheless, pipeline routing planning consents for a CO_2 pipeline are considered to present only minor new permitting considerations. A key issue is whether permitted development rights will be conferred on a CO_2 pipeline development application. This will be ultimately guided by national policy decisions regarding the relative importance of greenhouse gas mitigation - and the role of CCS within this - in national environmental priorities. In the US and Canada, large-scale CO_2 and acid gas pipelines are already in operation around the Permian Basin of West Texas for EOR and Alberta, and the US DOT, the *Railroad Commission of Texas* and the Alberta Energy and Utilities Board have well established operational and signage permitting requirements. The operational permitting approach adopted in US and Canadian jurisdictions can provide a useful guide to regulators elsewhere.

9.2 PERMITTING SUBSURFACE OPERATIONS

Unlike surface installations and operations, the subsurface element of a CCS chain presents a significant number of new considerations in terms of environment, health and safety permitting. Whilst there are similarities with existing activities in the oil and gas sectors in terms of the infrastructure required, the placing of a pressurised fluid into the sub-surface (as opposed to removing one) presents a whole new set considerations for regulators. The risk of potential major localised environmental, health and safety impacts, coupled with the potential risk that the actual global environmental objective of limiting atmospheric concentrations of greenhouse gases may not be met, leaves little doubt that effective regulation of CO_2 storage sites will needed going forward; at present, existing regulatory regimes cannot fully account for the safety and integrity of CO_2 storage. In this respect, several broad conclusions can be drawn:

i). *Need for new government-led regulation*: Given the complexity of CCS operations, the need to protect public and environmental health, and the potential long-term residual liability that may be underwritten by governments, government-led regulation rather than industry or self-regulation of storage sites will be needed. A lead on this is being taken by the Australian government, via its draft regulatory principles for geosequestration of CO_2. These form a useful set of guidelines against which to begin the regulatory development process. A number of EU Member States are forging ahead in considering their own storage site permitting process, largely based on the adaptation of existing regulatory instruments. In addition to this, the EU is likely to take some type of leadership on the issue in order to complement existing EU environmental regulations such as the EU ETS. International efforts through channels such as the *Carbon Sequestration Leadership Forum* could also see the emergence of some international guidelines and agreements on CO_2 storage site regulation in the longer term. Evolution of new permitting regimes will need to take into account existing international agreements such as the London Convention, Basel Convention and OSPAR. Any permitting system developed will need to provide evidence that sufficient assurances and accountabilities are in place to:

⇒ demonstrate storage site integrity prior to injection i.e. that storage selection has been carefully considered;
⇒ provide for ongoing performance measurement of the reservoir once injection commences;
⇒ ensure that appropriate responsibilities and commitments are in place with regard to the remediation of a leaking storage site;
⇒ ensure that some form of commitment regarding the future site decommissioning and abandonment process has been established;
⇒ ensure that appropriate consideration has been given to long-term liability for the storage site.

ii). *Requirement for extensive pre-feasibility studies and site characterisation et*c: The analysis compiled in this report suggests that extensively documented site characterisation will be required prior to the granting of a storage site permit. As yet, no analogous permitting regimes exist which can achieve the level of confidence about site integrity that regulators are likely to require for permit issuance. In this respect, the US has a well-evolved regulatory regime under the UIC regulations, and Canadian Provincial regulations make similar provisions in relation to acid-gas injection rules in some jurisdictions. Both require some form of injection site characterisation and pre-feasibility study, albeit for small volumes of materials. It is unclear whether these will be considered appropriate for CO_2 injection, or whether they will need to be adapted in the future to accommodate wider CO_2 storage deployment beyond R&D activities.

iii). *Ongoing site monitoring*: Deployment of an appropriate monitoring plan, and ongoing storage site monitoring, will be required in order to ensure that any storage site leakage can be detected. The monitoring plan is likely to form part of the license applications and subsequent conditions. Ongoing monitoring will be required in order to show that the site does not pose adverse environmental or health and safety risks. Public reporting of any leakage, including quantified estimates of the actual volumes leaking will be needed to conform with IPCC inventory requirements, and also under emissions trading schemes, should CCS be included.

iv). *Site decommissioning plan*: Some form of commitment with regards to the storage site decommissioning process at the time of site abandonment will be needed at the time of license issuance. Some form of assurance over the suitability of the well locations in terms of their ability to be capped may also be required in the initial site permit, such that the regulator can have confidence that the site can be successfully decommissioned with minimal environmental risk. Taking a precedent from oil and gas regulation, the storage site license is likely to incorporate a commitment to utilise best available techniques at the time of decommissioning, rather than committing to a specific technique upfront. A separate permit is likely to be issued in the run up to decommissioning, subject to the submission of an appropriate site decommissioning method statement by the operator. Agreement on how longer term liability will be handled may also be necessary at this point in the permitting process, although some consideration will likely be needed in the original site permit approval process. Liability about storage site operator insolvency will also need to be considered, with perhaps the need of some form of indemnity to ensure the costs of site decommissioning can be covered in this event.

v). *Need for an Environmental, Social and Health Impact Statement*: In all jurisdictions, it is likely that the undertaking of an ESHIA during storage site planning will be central to the full process. The established ESHIA process allows for many of the key issues to be considered by all stakeholders (government departments, local regulators, civil society, the public) via public and statutory consultation. The usual process is iterative, involving the preparation of a scoping statement outlining the key considerations, which are then commented on by stakeholders. The full ESHIA is then undertaken, consulted on, and any items of concern are subjected to further detailed considerations until all views and concerns have been addressed.

Many of these issues are subject to intensive ongoing research at a variety of levels. The information presented here reflects the situation at the time of writing, Summer 2005. In particular further guidance on some of the issues outlined could be forthcoming later in 2005 in the *IPCC Special Report on CO_2 Capture and Storage*.

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NOTES:

Annex I

UK enactments of EU environment, health and safety legislation relevant to CCS

I1.1 The Pollution Prevention and Control (England & Wales) Regulations 2000: SI 2000, No. 1973

These Regulations transpose the EU IPPC Directive into UK legislation, and elaborates on the Directive to incorporate UK specific requirements under the principle of subsidiarity.

I1.1.1. Sector specific guidance on BAT

Sector specific guidance has been issued by the EA, broadly mirroring the requirements laid out in BREF documents. The UK has also developed a process of options appraisal to assist in assessing BAT. An options appraisal must be undertaken in cases where the 'trade-offs' between reducing one pollutant and generation of other environmental impacts such as waste or increased energy use are evaluated (under *IPPC H1Guidance* note).

In addition the *IPPC H2 Guidance* specifies that energy efficiency is one of several considerations to be taken into account when determining BAT for the prevention and minimisation of pollution. In the case of a trade-off between increased energy consumption and improvement of other environmental objectives, the operator should undertake an environmental assessment, taking into account the costs and environmental benefits, to justify selection of the BAT for preventing and minimising pollution to the environment as a whole. The preferred methodology for this is provided in '*IPPC H1: Horizontal Guidance on Environmental Assessment'*.

Separate UK sector specific supplementary guidance has also been produced for mineral oil and gas refineries (*Box* I1.*I1.1*).

Box I1.1 Oil and Gas Processes Supplementary Guidance (IPC S3 1.02)

There are a number of methods available to reduce H2S concentrations in raw gas. The Sector Guidance describes the use of an amine solution to absorb the H2S and the 'rich' amine solution is then regenerated with steam.

The guidance defines the best available technique as:

'amine treatment of all significant sour gas streams to a level of 100 ppmv of H_2S or better'

In relation to the wastes produced by the amine scrubbing plant, the guidance states

'Contaminated scrubbing liquids, such as amines, should be recovered wherever possible, if necessary by off-site contract.'

Ultimate disposal method for reclaimed amine sludge is incineration at a hazardous waste facility.

The guidance requires evidence that waste arising and disposal issues have been addressed in the consideration of BAT. Due to the larger exhaust flow sizes, a CO_2 capture plant on a power plant would generate a greater amount of amine waste compared to processes in the oil & gas industry.

With regard to amine waste, BAT would be defined as recovery wherever possible and ultimate disposal of spent amine sludge at a hazardous waste incinerator.

The information in the supplementary guidance suggests that:

⇒ Use of amine scrubbing does constitute BAT in the *Oil and* Gas *Sector Guidance*.

⇒ BAT is defined by an acceptable H_2S concentration post scrubbing. For a CO_2 capture plant, an acceptable CO_2 concentration, or alternative, would need to be established.

⇒ BAT for waste arising from the use of an amine scrubbing plant is defined as regeneration wherever possible, with ultimate disposal at a hazardous waste incinerator.

⇒ The energy penalty for the capture plant does not have a direct parallel in the oil and gas sector.

Similarly, UK sector-specific supplementary guidance has been prepared for the large volume organic chemicals sector, relating to the use of amines for the removal of CO_2 to produce an H_2 rich stream for ammonia manufacture (similar to pre-combustion capture). This guidance is outlined below (*Box I1.2*).

Box I1.2 Guidance for the Inorganic Chemicals Sector (IPPC S4.03)

> The guidance states the following in relation to BAT:
>
> *' For new ammonia plants the following CO_2 removal processes give residual CO_2 concentrations In the range of 100 – 1000 ppmv and may be regarded as BAT;*
> *(1)AMDEA standard two-stage process, or similar,*
> *(2) Benfield process (HiPure, LoHeat), or similar,*
> *(3)Selexol or similar physical absorption processes.*

This guidance also suggests that amine scrubbing using any of these processes may constitute BAT in the context of pre-combustion decarbonisation and CO_2 capture.

However, it is important to note that while these processes are considered BAT for ammonia production, the production of H_2 is fundamental to manufacture ammonia. It could legitimately be argued that CO_2 capture plants are not fundamental to power generation. In this case, the inclusion of the plant would need to be considered in the context of an overall *options appraisal* adopting a whole process assessment approach.

I1.2 The Town and Country Planning (Environmental Impact Assessment) (England & Wales) Regulations 1999.

These regulations transpose the amended EIA Directive into UK legislation.

They provide specific details on the procedures and consultation processes necessary for undertaking an EIA of major developments in the UK, taking into account the institutional structures and relevant roles of different actors in the UK planning system.

For the purpose of brevity, the full complexities of the UK EIA system in the context of CO_2 capture plant have not been elaborated here, and the reader is referred to *Section 6.2.3* above.

Further details are also provided in the context of EIA for CO_2 transportation via pipelines (*Section 7.2.2.3*), and CO_2 storage sites (*Sections 8.2, 8.2.6, 8.3*).

I1.3 The Greenhouse Gas Emissions Trading Scheme Regulations 2003 SI 2003 No.3311

This Regulation transposes the EU ETS Directive into UK legislation. There are no UK specific issues in the UK implementation of the EU ETS that relate directly to CO_2 capture.

The UK National Allocation Plan (NAP; which determines the number of EUAs given to qualifying installations) has been reviewed on several occasions, and is awaiting approval by the European Commission at the time of writing. The UK NAP sets out an allocation of EU Allowances for a reduction in 5.2% below business-as-usual projections of CO_2 emissions from covered industries (equating to 756.1m tCO_2 for Period 1 of the EU ETS).

I1.4 The Large Combustion Plants (England and Wales) Regulations 2002 SI 2002 No. 2688

These Regulations transposes the LCP Directive into UK legislation. There are no changes to the qualifying criteria in the UK legislation.

I1.5 The Control of Major Accident Hazard Regulations 1999 (COMAH)

These Regulations transpose the Seveso II Directive (except for the land use planning requirements) in the UK.

The UK has taken a comprehensive approach to implementation of the Directive via the HSE.

The full details of these have not been included here for the purpose of brevity.

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