DEVELOPMENT OF A GLOBAL CO_2 PIPELINE INFRASTRUCTURE

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DEVELOPMENT OF A GLOBAL CO_2 PIPELINE INFRASTRUCTURE

Background

Projections of the scale on which CCS needs to be deployed to meet targets for CO_2 emissions reductions indicate that a massive CO_2 pipeline infrastructure will be required. To date CCS systems have tended to be based on dedicated pipelines connecting source to sink although some studies of regional CO_2 pipeline infrastructure requirements have been carried out. The purpose of this study is to examine the wider issues including design, financing, economics and regional differences.

Approach

A contract was awarded to a specialist engineering company Element Energy to work with pipeline specialists from Newcastle University and consultants on infrastructure financing to study the subject. Element Energy had already completed a study for IEAGHG as part of a consortium lead by Poyry Consulting in which they had used successfully a computerised Geographical Information System(GIS) to examine the potential for CO_2 storage in depleted gas fields. This work was an expansion of the source sink matching aspects of the Poyry study to include deep saline formations and depleted oil fields in the available sinks and to develop more details about the extent and cost of the required pipeline system. The savings which might be derived from combining sources into common pipelines were examined and also the financing mechanisms which might be used were explored and compared with those in common use for similar infrastructure developments. The IEA Blue map scenario figures for CCS capacity were used as a basis for estimates.

Results and discussion

General

The earlier work on potential for storage in gas fields made no attempt to consider the varying difficulty of the terrain between sources and sinks or the extra costs which crossing more difficult terrains would incur. Use of existing pipeline corridors was not considered. In this work an improved system was deployed whereby the GIS data was loaded with terrain difficulty information. The costs of straight-line pipelines were then based not just on their length but also the terrain which they crossed. In practice it should be noted that pipe-routes will not be straight lines but including such a terrain factor helps account for the need to deviate round obstacles or incur higher laying costs.

In the earlier work, data on location of gas-fields is quite location specific whereas it was found that much of the data on deep saline formations is far more generalized in some cases being only the delineation of large sedimentary basins where deep saline formations (DSF's) are likely to be found. Furthermore there is much greater uncertainty about the potential storage capacity of DSFs in contrast to gas and oil fields where an initial hydrocarbon capacity will have been established from early in the exploration process. Thus not only are the quantities which might be stored uncertain, also the location of suitable storage sites is often uncertain or unknown. The capacity difficulty is further compounded by the use of different methods to estimate capacity by different data sources. The injection locations also depend on whether whole formations or only structural traps can be used.

Required annual capacity

The annual storage capacities required by 2030 and 2050 in the IEA Blue map scenario are shown in the table below.

IEA Region	**2030**	**2050**
Africa	40	903
Australasia	129	353
Central+South America	52	476
Canada	148	574
China	307	2207
Eastern Europe	91	397
CIS	45	455
India	165	1153
Japan	42	129
Mexico	89	230
Middle East	60	505
Other Developing Asia	62	1093
South Korea	12	72
USA	495	1100
Western Europe	65.7	449.9
Total Mt/year	**1,802**	**10,097**

A key assumption in the analysis is that sinks with at least 20 years storage capacity have to be found to make it worthwhile to install a source –sink pipeline. Hence in 2030 projects connected to 36Gt of empty storage are required and in 2050 connections to 202Gt of empty storage.

Source-Sink matching

Algorithms were used to match sources and sinks for the CCS capacity requirements projected by the IEA Blue map scenario on two dates, 2030 and 2050. The matching respects the constraints of the date on which hydrocarbon reservoirs become available. Sinks are chosen to provide 20+ years of storage at the capacity of the connected sources. Thus in 2030 the model is looking for 36Gt of fresh storage. The model in effect takes a snapshot of all of the projects which are possible in 2030 and ranks them in increasing order of cost. This is then used to construct a cumulative capacity/cost curve in which the horizontal axis is the total amount which would be stored in 20 years and the vertical axis the costs per ton for the transport.

In meeting capture capacity there is no restriction on cross region transport. The model is allowed to use any pipelines between the sources and sinks which score below a certain threshold. This "score" is calculated taking into account the magnitude of the capturable CO_2 for the sink, the proximity and the terrain difficulty. In different regions different score thresholds were set so that unlikely pipeline routes would not be specified. A lower threshold was needed for example to filter out impractical lines crossing deep Norwegian fjords.

The exercise is repeated for 2050 but any sinks which have become full by then are excluded and also those projects from 2030 which still have storage capacity are allowed to continue. The model is now looking to have a total of 202GT of fresh storage to cover both the ongoing projects and those which are new in 2050. The total period covered is 2030-2070 and this simplistic model seeks to store a total of 238Gt by 2070. In practice the projects will be staggered and grow in capacity year on year. However modeling in multiple steps is extremely time consuming. The amount of CO_2 stored in this two step approximation will be somewhat less than the cumulative amount required by the blue map scenario which would be 345Gt assuming no further capacity increase after 2050. Bearing in mind these limitations the key results are as follows:-

In 2030, the model finds 1.4Gt/year of capacity can be installed using projects below the threshold scores. Even at this stage this is only 80% of the target 1.8 Gt/year

20 years later in 2050 0.8Gt/year of this capacity has been retired because the sinks are full but the model has been able to find a further 1.4Gt/year of capacity conforming to the threshold score giving a total of 2.2Gt/year However by 2050 capacity has to be 10Gt/year projected so there is a large shortfall. If modeled in finer steps the shortage of capacity would be even greater.

Deep saline formation capacity and location of injection points.
The study attempts to use the latest published data for deep saline formation capacity and in many instances this may be out of date. It also attempts to use a standard estimate based on application of appropriate coefficients to pore space information. As baseline and where available, published figures for 'effective' (CSLF) or 'resource' (US DOE) storage potential have been used and in other cases 2% of total pore space.. There are anomalies in the data for example Canada has no recent published data on a country basis but capacity in Western Canada is included in the Plains CO_2 Reduction Partnership (PCOR) data.

Unless the approximate location of specific DSFs is known these are specified in the GIS as large polygonal areas somewhere in which a certain storage capacity resides. In many cases these areas are simply the outline of sedimentary basins within which suitable storage formations are expected to be found. The model has to connect between discrete points which for sources is not a problem but for DSFs means that a "connection" location has to be generated. In the absence of more location data the model does this by choosing points in the polygonal areas at random and this is presumed to be the centre of distribution hub to the real reservoir locations. Even so individual pipeline lengths may be quite unrealistic but the global aggregate will be more realistic. Even at the regional level aggregate lengths may be questionable because there is too little data on DSF location.

Cost trends

The results of the analysis show how the marginal cost of adding more capacity increases and is illustrated in the following figures.

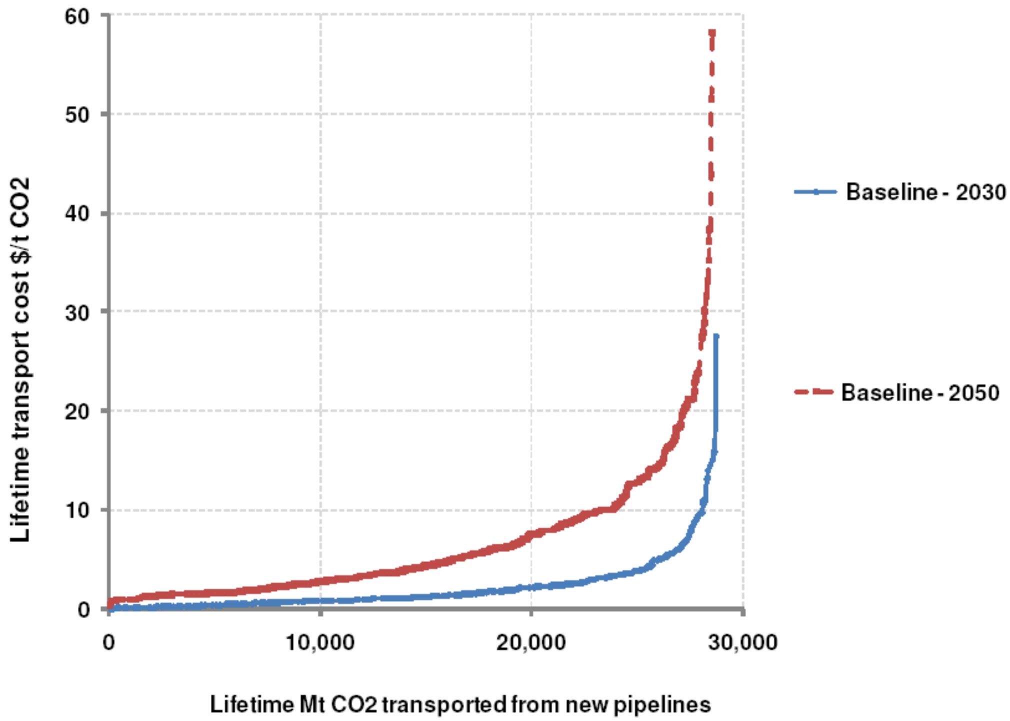


Figure 15 Global marginal cost curves (transport only) for new pipelines in 2030 and new pipelines in 2050.Each point on the curve corresponds to the CO_2 and cost for a single source connected to a single sink with baseline scenario assumptions. The points are ranked in order of cost.

The first chart (Figure 15 in the main report) shows the marginal cost curves from the two step model searching to meet the global and regional capacities required by the blue map scenario in 2030 and 2050.

The next chart (figure 13 of the main report) shows how individual regions fare on a cumulative cost basis in 2030 highlighting that some regions already have considerable difficulty in reaching capacity even though globally about 80% can be reached.

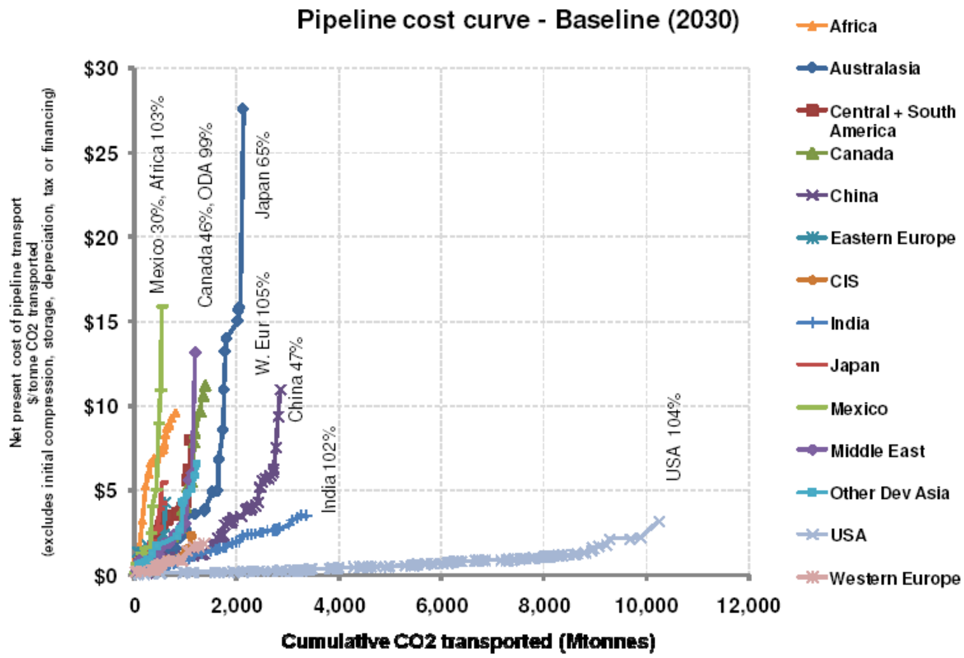


Figure 13 Regional marginal cost curves (transport) in 2030 and 2050. IEA Blue Map is the CO_2 target for each region.

The next chart (Fig 8 from main report) shows how total capacity in each region compares with that required for 20 years of injection. By comparing these, an idea can be gained as to how much it is proximity and how much simple lack of capacity which

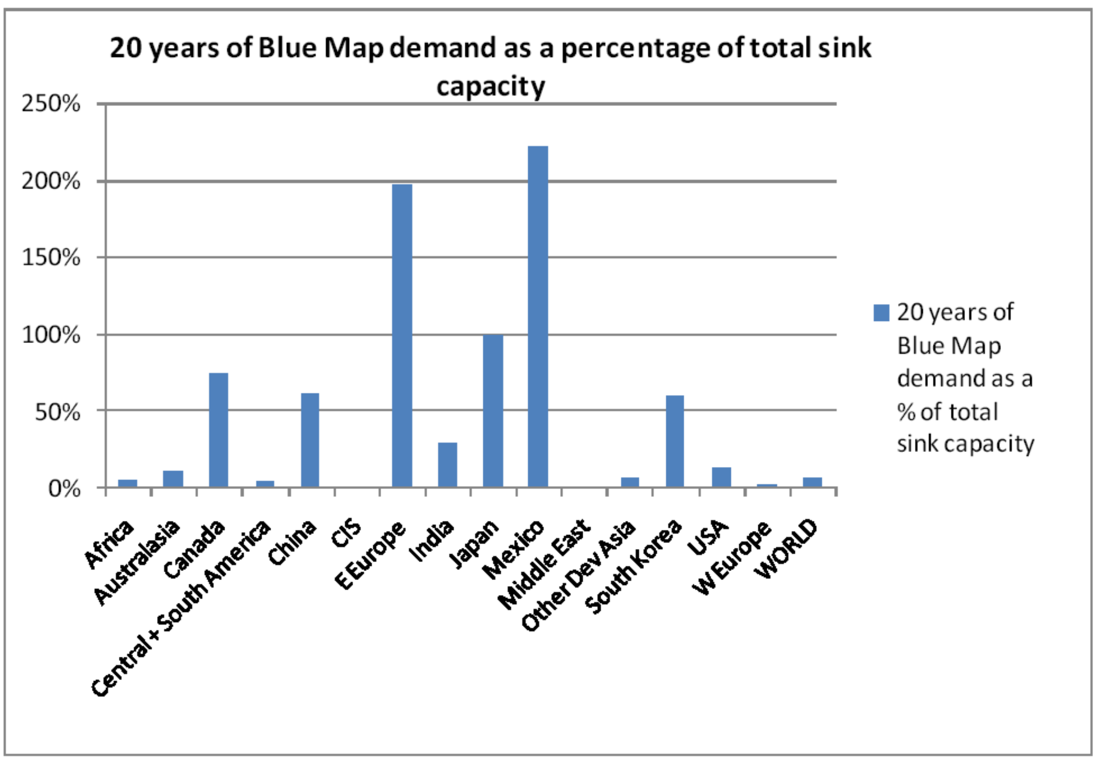
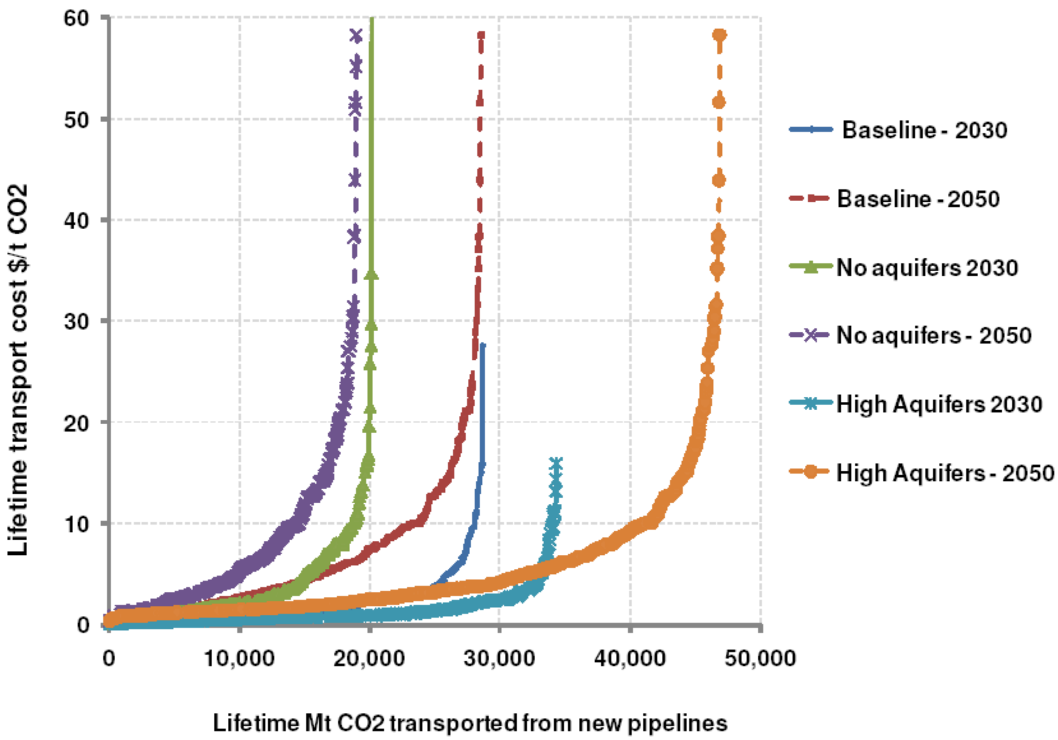


Figure 8 20 years of Blue Map demand as a proportion of total sink capacity prevents regions from reaching their targets. Mexico for example does not have the capacity whereas China has nearly double the required capacity but can only use about 25% of it at reasonable cost to fulfill just 47% of blue map requirements. The low costs in the USA largely reflect short transport distances.

Sensitivity to deep saline formation storage capacity

Until more data is published on DSF storage capacity it is not possible to meaningfully alter the model on a regional basis. The DSF capacities used are based as far a possible on conservative assumptions e.g that only 2% of pore space can actually be used. The results assuming no DSF capacity and 10% rather than 2% pore space utilization, (i.e. capacity 5 times greater) were also modeled with the global results shown in the chart below. The conclusion is that if storage capacities were higher in existing locations costs reduce significantly but there is not a proportionate increase in total affordable capacity. In other words there is a global shortage of known storage capacity near many sources. In 2030 it becomes possible to meet global targets at a slightly reduced cost. In 2050 about twice as much can be stored at the same cost but this is still far short of total requirements.



Integrated infrastructure

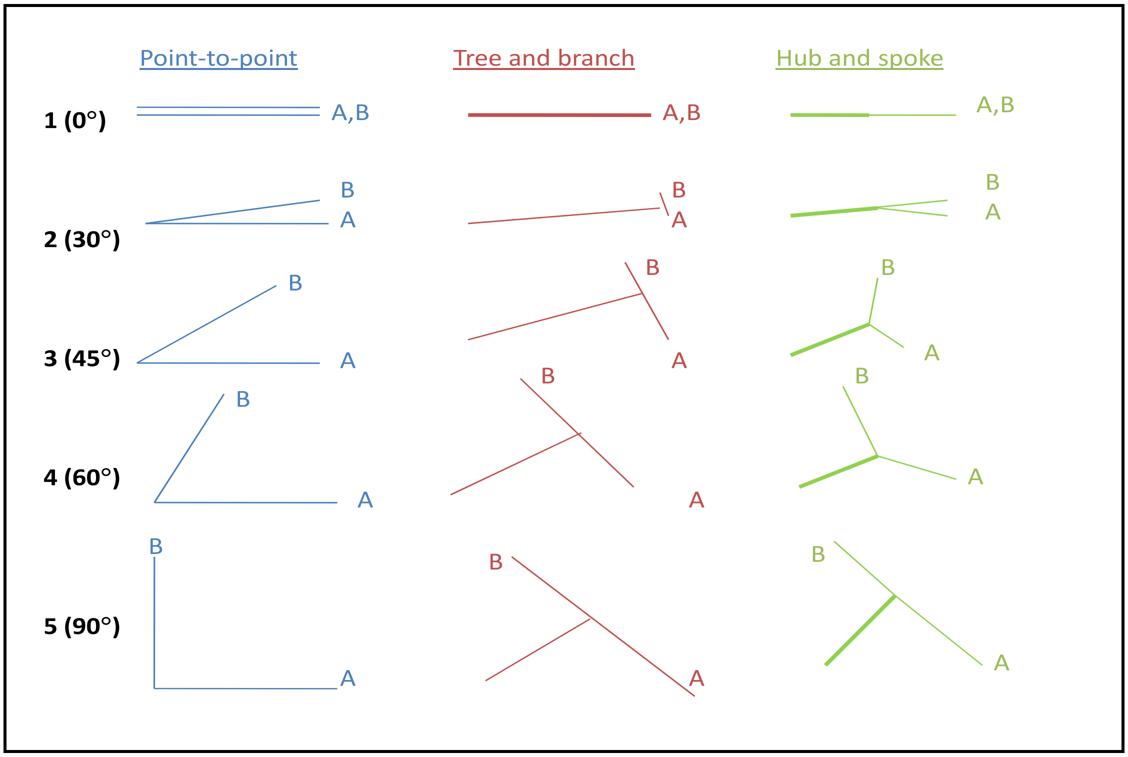
The baseline analysis uses a single dedicated pipeline between each sink and source. In practice it may be possible to share sections of line thus reducing costs. The scope to do this was investigated by inspecting clusters of sources using the same sink to see whether parts of the pipeline could be combined. This was screened with a simple algorithm. When clustering possibilities were indicated a simple routing whereby a single central line is joined by intermediate sources connecting to this line by the shortest (hence orthogonal) distance is used. Lines sizes and costs for each segment are then calculated based on capacity, length and terrain. Whilst this does not produce the minimum cost network it captures most of the potential saving. The results are summarized in the table below and give a rough indication of the potential saving in pipeline infrastructure. Worldwide nearly 60% of pipelines are found to be amenable to clustering and within clusters this would save a calculated 46% in length. The corresponding cost reduction would be less as the lines are larger, perhaps half this amount which at first sight would be a worthwhile reduction. However the economics would need to be carefully assessed. If the phasing of capacity results in lines being significantly underutilized for even a few years at the start of integrated projects a 20% saving in upfront costs could be more than negated by reduced revenues if typical commercial discount rates are applied.

The colours in the table overleaf indicate where interesting integrated systems are most likely to be found based on the source-sink data presently available.

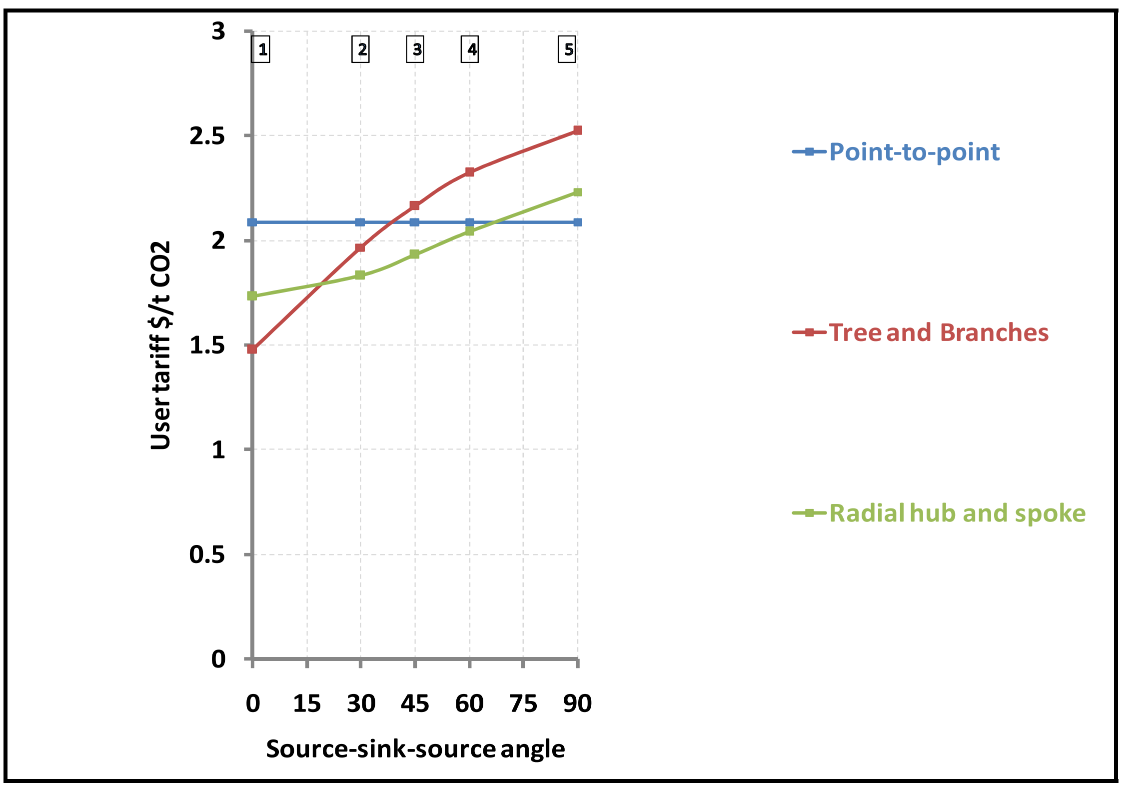
Region	Total Point to Point Pipeline Length (km)	% of CO_2 in clusters (Central scenario)	Length saving in central scenario (km)	% change in length within the clusters	% length saving overall
Africa	21,214	77%	7,579	46%	36%
Australasia	0	0%	0	0%	0%
Canada	0	0%	0	0%	0%
Central + South America	17,267	59%	4,359	43%	25%
China	7,063	50%	2,452	69%	35%
CIS	25,809	80%	6,988	34%	27%
Eastern Europe	386	39%	33	22%	9%
India	3,737	31%	851	74%	23%
Japan	0	0%	0	0%	0%
Mexico	0	0%	0	0%	0%
Middle East	8,913	62%	3,072	55%	34%
Other Dev Asia	13,702	58%	3,166	40%	23%
South Korea	0	0%	0	0%	0%
USA	22,227	49%	4,235	39%	19%
Western Europe	9,767	61%	2,629	44%	27%
World	**130,085**	**59%**	**35,364**	**46%**	**27%**

Economics of integration

The report examines the economics of integrating pipeline systems in an appendix. Simple scenarios in which two sources connect to a single sink with varying angles between the direct routes, varying capacities and startup timing of the two sources are analysed. Once the angle between direct routes exceeds 60 degrees there is no economic incentive to build an integrated system. As would be expected small sources gain considerable advantage in joining an integrated system whereas the large source may even be at a disadvantage unless tariffs are suitable adjusted. The overall tariff reductions are not that large. Two structures were examined in some detail, hub and spoke and tree and branch layouts for direct source-sink lines 30 degrees apart. In the examples analysed these gave overall tariff reductions of 12% and 6% respectively.



Examples of interconnection geometries



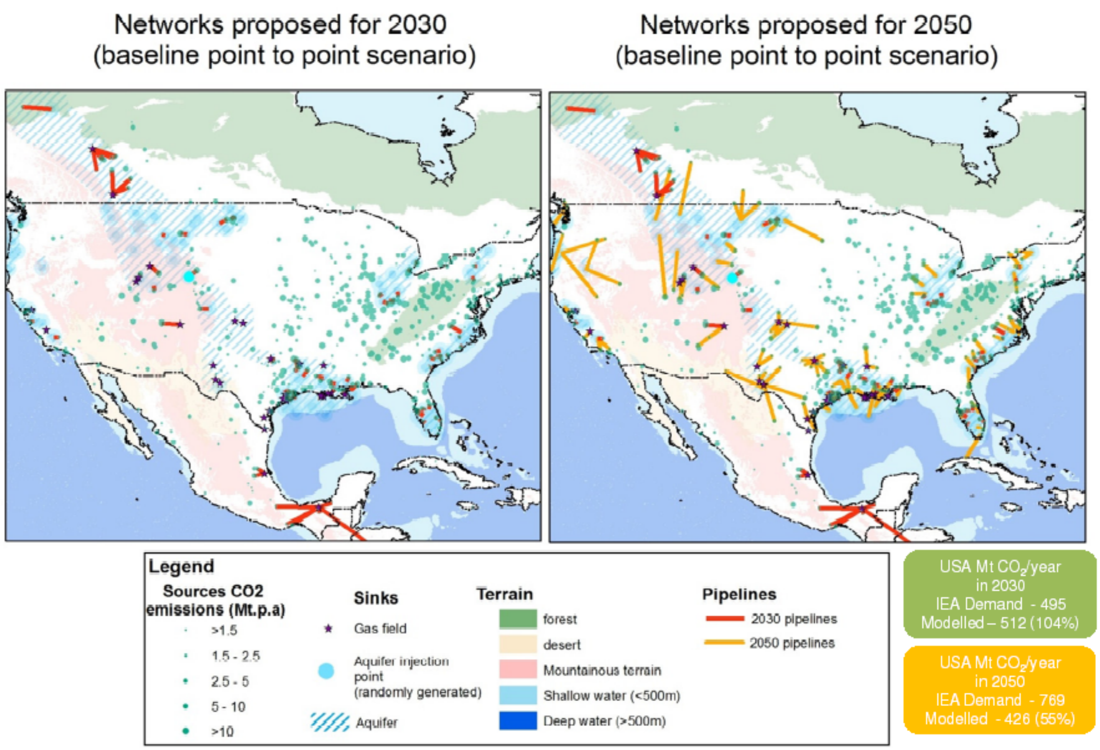
Example of relative tariffs for different integration geometries – 2 equal sources of 10Mtpa each 100km from sink at different direct route angles.

The consequences of delay in both startup of one of the sources or in overall construction for whatever reason are significant. If start up of one of two equal sources is delayed by more than 7 years there is no advantage in an integrated system. The analysis also shows that extending construction time raises average tariffs by about 5% for each year of delay. Thus if a more complicated system takes significantly longer to build and commission the economic advantages of integration could easily be lost.

The figures below show the basic geometries which were analysed and how the tariffs would vary for two equal sources connected in different configurations.

Examples of networks

The GIS system produces maps showing the proposed pipeline systems in the years chosen for analysis. The report contains maps for all the world regions for both 2030 and 2050. The North American maps are shown below and illustrate a number of points. Firstly it is notable that in 2030 there are not very many lines showing on the map. This is because at this stage lines are short. In 2050 longer distance lines emerge but note also that there are insufficient sinks close enough to sources to satisfy the full Blue map demand. It is also evident that only a fraction of sources are connected even by 2050 and many areas do not have nearby sinks. 18 maps covering the main world regions in 2030 and 2050 are appended after the main report.



Baseline point-to-point modelled networks for USA.

Legal issues

The report reviews the legal impediments which might hamper development of international CO_2 networks. The following are considered:

NAME	APPLICABLE TO:-
Basel Convention	Transboundary waste movement
Basel Ban amendment	OECD- non OECD waste movement
Bamako Convention	Waste movement to Africa
UNCLOS	Maritime transfer/transformation of hazards
London Convention	Protection of marine environment (Global)
OSPAR	Protection of marine environment (North Atlantic)
UNFCCC accounting conventions	Accounting for CCS based emission reductions
EU CCS Directive	Purity, network access, dispute resolution etc.

No insurmountable impediments are foreseen but some development is needed in some of these legal instruments. The waste movement conventions need to establish the status of CO_2 which the report writers suggest could best be treated as a special case in the same way as already done by the London and OSPAR conventions. As yet the conferences of parties of the waste conventions have not addressed the matter. UNCLOS is not considered to impose any impediments. UNFCCC needs to formally adopt the latest (2006) version of the inventory accounting guidelines as the currently valid versions do not address CCS. The EU Directive already provides the required enablement including addressing minor conflicts with other EU directives.

Planning constraints

The chart below illustrates how long planning approvals for major infrastructure projects in various European countries can take but may not be representative of other regions.

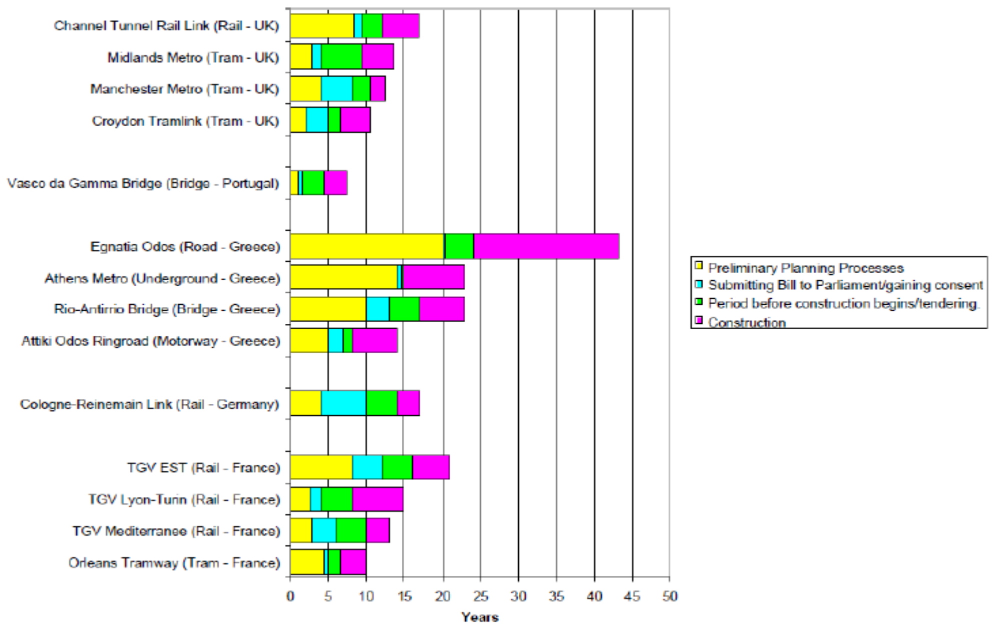


Figure 20 Length of the planning procedures of major transport projects by country. Original copyright Association for European Transport, 2003.

Pipeline projects which span countries will need to complete procedures in all those countries which could further increase approval time. Also certain elements pertaining to CCS such as safety, public perception, political support can affect the timing and outcome of the planning process in either direction.

National regulations

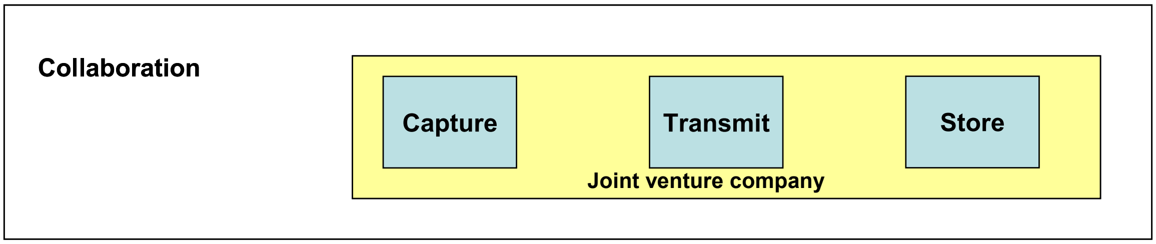
The report provides a more detailed overview and update of regulatory and permitting considerations in USA, Australia, Canada and the UK. These were addressed in an earlier IEAGHG report in 2006. In most regions efforts to clarify the regulations affecting CO_2 pipelines are underway but the process needs to be completed.

Financing of CCS infrastructure

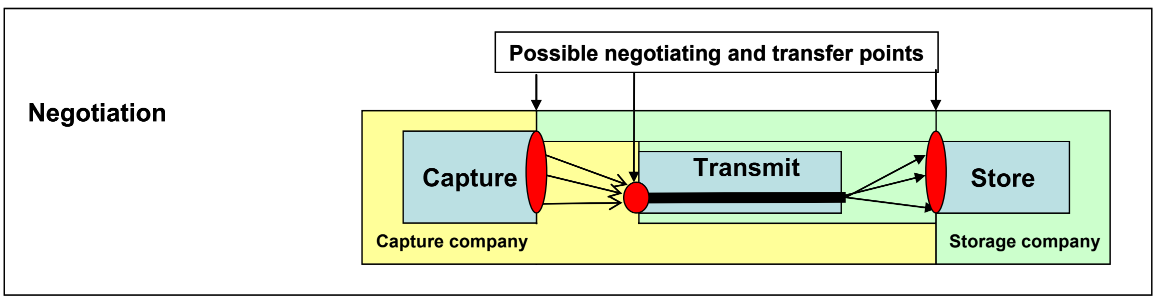
The report looks at the way in which oil and natural gas pipeline infrastructure is financed and how this has changed over time. There have been extremes ranging from complete vertical integration as in the early oil industry to the almost completely deregulated natural gas market which has finally been established in the USA. Historically the lowest costs are have been reached by the fully deregulated markets as long as full competition prevails.

Early CCS projects are expected to need significant government support and thus will not be established in a deregulated fully competitive environment. The report argues that if the benefits of such an environment are to be harnessed a process of transition in the direction of a free market will have to occur. In order specifically to minimise costs of transmission of CO_2 effective markets in both primary and secondary CO_2 transmission capacity will have to exist in addition to CO_2 markets.

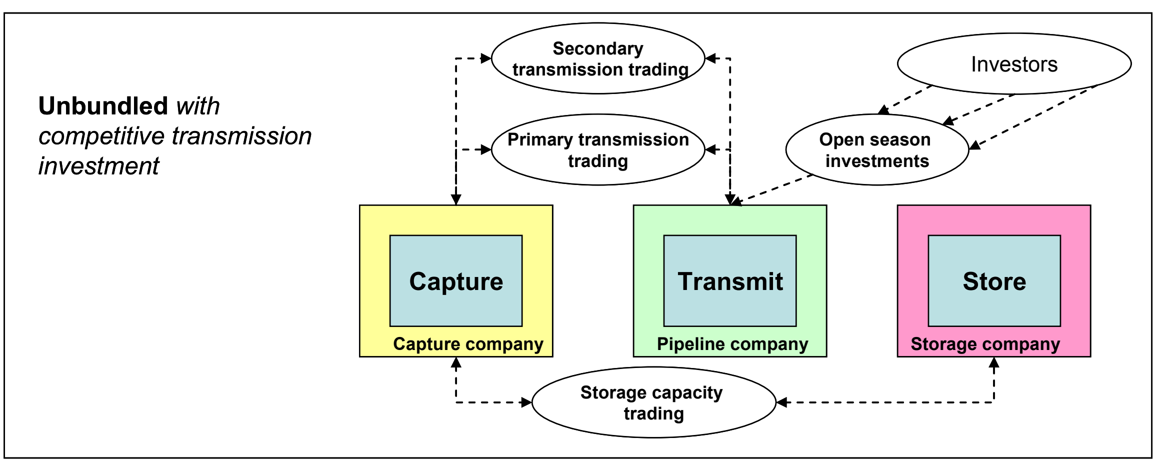
Based on the various structures seen for oil and gas markets it is suggested that three possible structures might emerge for CO_2 pipeline transmission. The first is dubbed "collaborative" and entails setting up joint ventures which invest in and run complete CCS systems consisting of capture transmission and storage.



The second dubbed "negotiation" sees the two main elements run by separate enterprises with the transmission segment included to greater or lesser in the capture venture or the storage venture. A negotiating point at the points of collection, the entry into the CO_2 trunk line system or the exit of the trunk line system will be the interface at which the price to be paid for transmission plus storage or capture plus transmission will be contracted between the parties. This is better suited to projects where there are multiple sources or sinks.



The final model dubbed "unbundled" sees separate entities running capture transmission and storage. A set of markets surrounds the system in which primary capacity is traded as well as surplus or shortfalls on a secondary market akin to that used in natural gas markets. An "open season" mechanism is used to enable investors to create new capacity. The three models are illustrated in the diagram below.



The emission market will be different to the oil and gas markets with cap and trade limits likely to be the main driver of capacity and price. How and whether a fully competitive market for CO_2 transmission capacity can be constructed more or less from scratch is debatable. Historically the other markets have evolved over many decades after much regulation and negotiation. However the positive experience with financing systems for oil and gas transmission can be used to try to construct as free a market as initial funding arrangements will allow.

CCS projects whether just the pipeline element or the whole system will require finance which can be in any ratio of debt to equity. Uncertainty as to CO_2 revenues will make it more difficult to use debt. The World Bank and similar international lending institutions can be a suitable source of finance as long as the projects comply with certain ethical principles – either IFC's or those adopted as "Equator principles" many of which are based on IFC requirements. The role of national governments can be as guarantors, equity partners or financial supporters.

Engineering considerations

The report includes an overview of key engineering challenges in building large scale CO_2 pipeline systems and touches on issues relating to reuse of existing lines built for service with other fluids. The one challenge which stands out as potentially restrictive is assuring safety in the event of a major leak. Although the probability of such an event can be reduced to very low levels experimental validation of leakage scenarios remains a key need. Without this information potentially severe restrictions and delays may be encountered in permitting and planning processes.

Expert reviewers comments

Reviewers found the report interesting but were concerned about the quality of the data available on deep saline aquifers. The report text was modified to indicate clearly that this data is highly uncertain and thus specific conclusions about the future requirements for CO_2 pipeline networks for particular regions should not be drawn from this work. A number of specific comments were received concerning terminology used to describe the phase behaviour of CO_2 and also the effects of impurities on this. The text was modified where appropriate to make this clearer, more balanced and consistent. .It was pointed out that the original text underplayed the depth of experience with design, regulation and operation of long CO_2 transport lines which has been accumulated in the United States. The text was modified to reflect this experience although references to the obstacles to transferring this to other jurisdictions, with different climatic and demographic conditions were retained. It was also pointed out that the large scale of CO_2 EOR operations was underplayed in the text and a revision was made. Also that in the USA the FERC were not likely to take up regulation of CO_2 lines as originally suggested in the text which was amended.

Conclusions

In order to meet projected long term CCS storage requirements a massive increase in identified DSF storage capacity reasonably close to major emission sources is needed in many regions. Unless exploration and characterization activities can deliver this the costs of transmission of CO_2 from sources to sinks becomes excessive. Globally there is adequate capacity but much of it is too far away from emission sources to be used. However in the shorter term up to 2030 there appear to be sufficient opportunities to provide low cost transport through manageable terrain over short routes. While some countries seem better endowed with storage capacity the analysis does not indicate much advantage in redistributing the CCS targets proposed in the IEA blue map scenario between the regions.

The nature of large integrated CCS systems will encourage vertical integration of capture, transport and storage as well as risk sharing through joint ventures. From the free market point of view this will not deliver lowest costs and may restrict growth of optimally shared pipeline infrastructure. Interventions to promote free market such as freedom of access rules and unbundling can be used to help unlock the potential. The routing analysis indicates that significant savings may be possible from integrating transport networks in over half of the system global system. However in many cases dedicated point to point systems will be appropriate.

There are some remaining legal impediments to trans-border systems which should be relatively easy to address.

Recommendations

IEAGHG should seek to encourage the characterization of DSF storage capacity as a matter of urgency building on the work of recent and ongoing IEA GHG studies in this area. The model results should be used to help define priorities for allocation of resources to the task.

The model is improved since it was first used for assessing the potential of depleted gas fields and further refinements can be made. Further studies using the model to extend or update this work should be considered. Other organizations should be encouraged to use this or similar computerized GIS methods to further explore CO_2 pipeline infrastructure. In so doing further refinements to the model should be encouraged, for example adding more detailed terrain and routing data, potentially re-useable pipeline data, better definition of DSF locations and faster turn round times for the computer runs.

CO_2 pipeline Infrastructure:

An analysis of global challenges and opportunities

Final Report

For

International Energy Agency Greenhouse Gas Programme

12/05/2010

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Element Energy Limited is a low carbon consultancy providing a full suite of services from strategic advice to engineering consultancy in the low carbon energy sector. Element Energy's strengths include techno-economic forecasting and delivering strategic advice to clients on all opportunities connected to the low carbon economy. Element Energy has experience in the design of strategies for the coordinated deployment of low carbon infrastructure.

The CCS Transportation Research Group at the University of Newcastle was set up by Prof. Martin Downie in 2005 and includes Dr Julia Race and Patricia Seevam. With its experience in marine technology and pipeline engineering, the group is investigating pipeline and ship transport options. Key research areas include: assessment of the technical requirements for onshore and offshore CO_2 transport systems in the UK, economic assessment of viable transport options, examination of the viability of the existing infrastructure for CO_2 transport, and investigation of additional regulations that may be needed for CO_2 transport and how they might affect system design and equipment choice.

PAUL HUNT

Paul Hunt is an independent energy sector consultant. He began his energy sector career as Corporate Economist for Bord Gáis Éireann in 1986. His major areas of work are gas industry structure and regulation with a specific interest in the development, financing and pricing of services on gas transmission and distribution networks. Beginning with significant involvement in the UK's gas market liberalisation from the late 1980s the geographical scope of his work has expanded and he has considerable international experience throughout Europe, Africa, the Middle East, Russia and East Asia.

Carbon Counts specialises in international climate change policy, focussed on financing and regulation. It has advised the UN, World Bank, European Commission, UK government, Thai Government, many private sector organisations including several FTSE25 companies on energy & climate related matters, covering preparation of greenhouse gas inventories, development of renewable energy strategies, implications of emissions trading, and implementation of carbon reduction and optimisation strategies. It has expertise in the fields of carbon capture and storage, and clean development mechanism.

CAVEAT

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of CCS. The available data on sources and sinks are extremely limited and thus the analysis is based around hypothetical scenarios. The maps and costs are provided for high-level illustrative purposes and no detailed location-specific studies have been carried out. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of IEA GHG.

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HIGHLIGHTS

CO_2 pipelines will form an essential dimension to the deployment of carbon capture and storage technologies. This report examines by review and quantitative modelling several key issues affecting medium and long term global CO_2 pipeline deployment.

While transport of CO_2 by pipeline is in most aspects mature (e.g. as demonstrated onshore in North America and offshore Norway), experience and many guidelines in most countries are inadequate to deal with: dense or supercritical phase transport of CO_2 captured from power or industrial sources, particularly in densely populated areas; the management of corrosion and the effects of impurities.

For CO_2 networks connecting multiple sources and sinks, clear entry specifications are required – these will have an impact on the development of CO_2 capture and storage technologies.

Currently, the lack of CCS operational experience, the absence of sufficient and long-term financial/regulatory drivers, and large uncertainties on the locations, capacities and timing of sources and sinks stall the commercial development of large scale CCS pipeline infrastructures. Reducing these barriers - which affect all aspects of CCS - requires urgent attention.

Until these barriers are removed, public support to organise stakeholders, reduce costs and risk is likely to be required to initiate significant investment in pipeline networks.

Assuming a sustained competitive market for abated CO_2 does materialise, then risk and reward allocation instruments, such as project financing, which are frequently used to fund oil and gas pipelines can be developed to fund pipelines. Typically these involve a mixture of debt and equity funding from a consortium comprising key 'upstream' or 'downstream' stakeholders. There are clear lessons from the natural gas pipeline and other low carbon energy industries in incentivising timely, efficient investment and use of these pipelines.

A set of GIS and spreadsheet models have been developed to provide capacity and cost estimates for the worldwide potential for CO_2 transmission pipeline infrastructures. Demand level scenarios, sources and sink databases were developed in agreement with IEA GHG. The absence of consistently formatted and high quality worldwide datasets of likely future sources or validated sinks is a major limitation in any analysis – for this study only scenarios of availability are examined - this may also pose a challenge for global CCS policy support.

Under the modelled baseline, it is possible to store CO_2 equivalent to 80% of the IEA Blue Map CCS demand in 2030, without incurring excessive pipeline costs. There is wide variation in regional achievement; Western Europe and the USA in particular are able to approach the 2030 demand using low cost networks.

With few potential opportunities in depleted giant gas fields relative to demand, a number of regions, including Australasia, China, Japan, and South Korea are heavily dependent on aquifers for storage in 2030.

Under the modelled baseline, just 15% of the 2050 Blue Map target is achieved through matching existing sources with an illustrative baseline sink database. At a global level, it is challenging transport solutions (e.g. excessive pipeline lengths between modelled source and sink locations), rather than the availability of sink capacity, which prevents the world from meeting a large proportion of the CCS target.

A large quantity of 'unmatched' capacity is found in sink clusters (e.g. in the CIS and Middle East) that are located large distances from clusters of sources.

In many regions, integrated networks, where sources connect to a common trunk pipeline, can deliver significant length and cost savings relative to 'Point to Point' networks. Globally, the reduction in total pipeline kilometres is 25%, with a corresponding reduction in CO_2 transport costs.

The economic case for integrated CO_2 pipeline infrastructure vs. independently developed pipelines will vary considerably between locations and over time. Where the geometric configuration of sources and sinks favours integrated pipelines, the economics will particularly benefit smaller sources. A challenge will be to ensure that any pipelines that are initially 'oversized' do achieve full utilisation very quickly. In any case, Governments, industry and independent stakeholders can and should work together to reduce the risks of CCS and thereby reduce the cost of financing CO_2 pipeline infrastructure.

Considering the experience of other major transport infrastructure projects involving multiple stakeholders, large scale integrated CCS projects may take more than a decade from conception, through financing and construction, to eventual operation. For shared pipeline infrastructure to be operational by 2030, investment commitments may need to be made by the early 2020s. In addition to a stable and supportive regulatory environment, these decisions will require diverse stakeholders to possess data (and confidence) on capture and storage locations, costs, capacities and utilisation. In most countries, this will requires a step-change in data collection, analysis, and sharing, as well as greater operational experience developed through the CCS demonstration phase.

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1 EXECUTIVE SUMMARY

Carbon dioxide Capture, transport and Storage (CCS) is part of a portfolio of climate change mitigation options available to policy makers and industry. Where pipeline infrastructure designs, financing and regulation are optimised, the scale, cost-effectiveness and public acceptability of transporting CO_2 are improved. This improves the likelihood that pipelines can be financed and deployed quickly and that challenging atmospheric CO_2 stabilisation targets can be met.

The major challenges for CO_2 pipeline infrastructure are explored in this report and are:

- engineering design of pipelines
- matching supply and demand
- overall cost and capacity
- financing, legal and regulatory issues

1.1 Engineering Challenges

An engineering analysis of health, safety and environmental issues associated with CO_2 pipelines and pipeline networks reveals that there are few technical impediments to CO_2 transport by pipeline. Four issues dominate from a technical perspective.

The first technical issue is that long distance CO_2 transport is likely to involve supercritical or dense phase transport across more challenging terrains (e.g. close to urban centres and offshore) than has largely been the case historically. Existing engineering and regulatory guidelines and experience worldwide (and particularly outside of the US or Norway) are therefore limited.

The second technical issue is that even 'overwhelmingly pure' CO_2 streams from capture plants are likely to have levels of impurities that have the potential to impart different physico-chemical properties to the CO_2 and increase the engineering design complexity compared to existing CO_2 pipelines. Very few engineers and safety professionals worldwide currently have the skills and experience to make informed decisions on appropriate designs (e.g. levels of impurities) for the safe transport of captured CO_2.

The third technical issue is that, unlike CO_2 transported from naturally occurring sources for enhanced oil recovery, the amount of CO_2 from power and industrial sources is likely to be variable. This will necessitate careful management of CO_2 flow to avoid phase changes within the pipeline. Guidance on management of intermittency in CO_2 pipelines is extremely limited.

Fourth, common entry specifications for CO_2 pressures, temperatures and concentrations of impurities would be required where multiple CO_2 sources connect to the same pipeline network. This could impact the choices (and costs) of capture, compression and drying technologies. CO_2 sources may not always be able to disclose details of their capture technologies and, implicitly, their business plans. This may be through lack of certainty or for commercial or competition reasons. In these cases, a storage-led or transport-led company, rather than a capture-focussed company, may seek to define entry specifications. Where a transport or storage-led focus does emerge, this may restrict capture technology choices (and thereby have an impact on innovation, costs and CO_2 volumes). As an example, significant oxygen impurities from oxyfuel capture may be incompatible with CO_2 storage coupled to enhanced oil recovery. Alternatively, the resulting incremental purification costs to reduce impurity levels to allow sources using different capture technologies (e.g. pre-combustion and oxyfuel) to connect to the same pipeline network may be less than the costs for each source to construct and develop its own transport solution.

1.2 An optimised model of CO_2 infrastructure in 2030 and 2050

With CCS in its infancy, and huge uncertainty on capture and storage potential, there are no existing worldwide databases identifying the locations of CO_2 capture plants, capacities or locations for CO_2 storage. Therefore to inform this study on pipeline infrastructure, a set of GIS and spreadsheet models were developed to provide first order capacity and cost estimates for the worldwide potential for CO_2 transmission pipeline infrastructure for networks developed in 2030 and 2050, based on scenarios for sources, sinks and demand developed in agreement with IEA GHG.

Drawing on recent IEA GHG analysis, databases of worldwide potentially suitable CO_2 sources and CO_2 sinks (giant gasfields and hypothetical injection points within saline aquifers) were prepared in Geographic Information Systems (GIS) format. Recognising the enhanced uncertainty associated with aquifer storage, three scenarios of aquifer availability were modelled. GIS/spreadsheet models were then created and used to identify and rank paired source-sink combinations worldwide on the basis of proximity, capacity, timing, intermediate terrain, and clustering potential.

The highest ranking combinations above a threshold can then be shortlisted for each region in order to meet a given demand. The IEA's ETP 2008 'Blue Maps' for 2030 and 2050 estimate the contribution of CCS worldwide which is required to meet an atmospheric CO_2 stabilisation target of 450 ppm[1]. This target was disaggregated into the CCS demands for 15 regions worldwide and used to guide the 'baseline' demand modelled in each region. While many of the regions, and the world as a whole, are able to meet the demand using a small proportion of their modelled sink capacity (including gas fields and aquifers), others, such as China, require the majority of their sink capacities to be connected to meet the target.

[1] IEA (2008) Energy Technology Perspectives: Carbon Capture and Storage

1.3 Results of source-sink matching and network design optimisation.

The cumulative transport of 1.44 Gt CO_2/year worldwide is modelled for 2030 in the 'baseline scenario' using 358 sources representing circa 80% of the blue map target. If these CCS projects are developed individually, i.e. on a point-to-point basis, the overall pipeline length is more than 43,000 km. The median distance between sources and sinks is 81 km. The median price for a source-sink connection is \$1.5/t CO_2 transported although the marginal cost, particularly in 2050, can be significantly higher. The net present worldwide combined capital and ongoing costs of the pipelines and boosters (including energy costs) for these networks amounts to \$60 bn. This figure excludes costs associated with capture, initial compression, storage or financing. The scenario includes at least 9 pipelines longer than 500 km.

Examination of the marginal transport cost curve for these pipelines reveals that, for projects beginning in 2030, more than 20 Gt CO_2 can be transported with an average cost of less than \$5/t CO_2, assuming an economic life of 20 years. However, the marginal costs for transport above 20 Gt rise steeply to \$30/t, as combinations of sources and sinks that are less attractive must be used.

Considering 2050, the availability of giant gasfields with late close of production dates provides new opportunities for cost effective CO_2 transport. However, the cost effectiveness overall for new pipelines is now significantly lower as more challenging distances and terrains must be crossed, and there is greater emphasis on smaller sources for which transport is less economic.

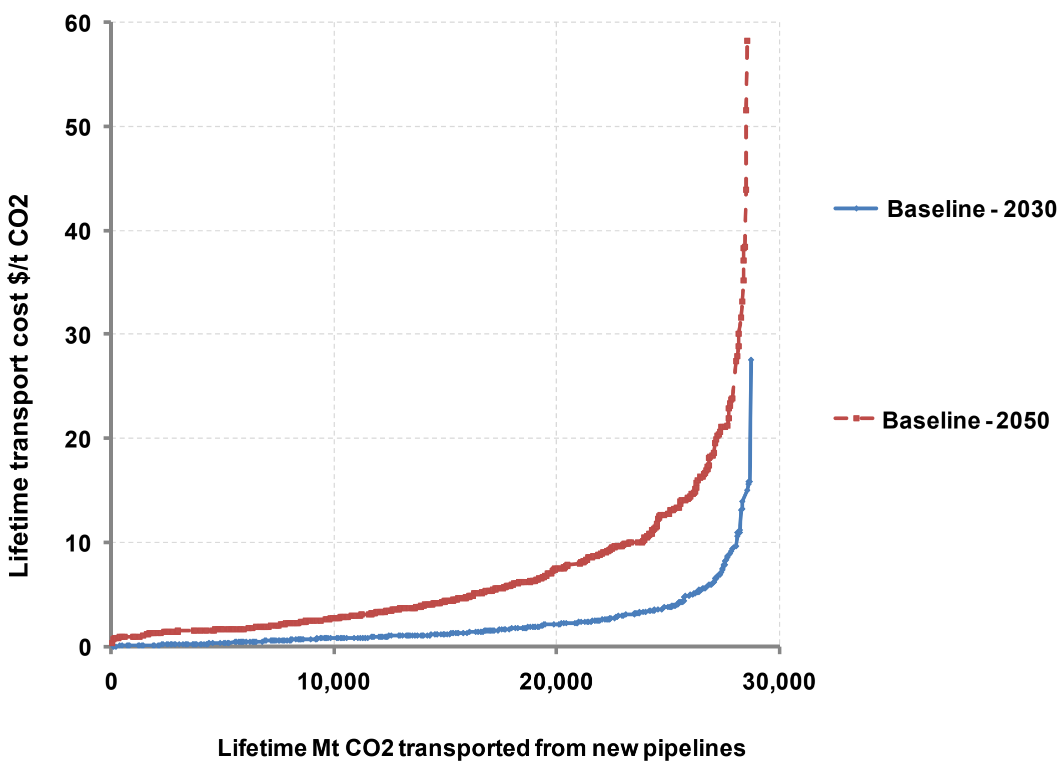


Figure 1 Marginal cost curves for CO_2 transport from *new* pipelines modelled for 2030 and new pipelines modelled for 2050 for a baseline scenario using point-to-point networks only. Costs relate to pipelines and boosters only and exclude capture, initial compression, storage or commercial financing.

The substantial differences between regions in the cost-effectiveness of CO_2 pipeline transport is most clearly highlighted through the marginal cost curves shown in the image below.

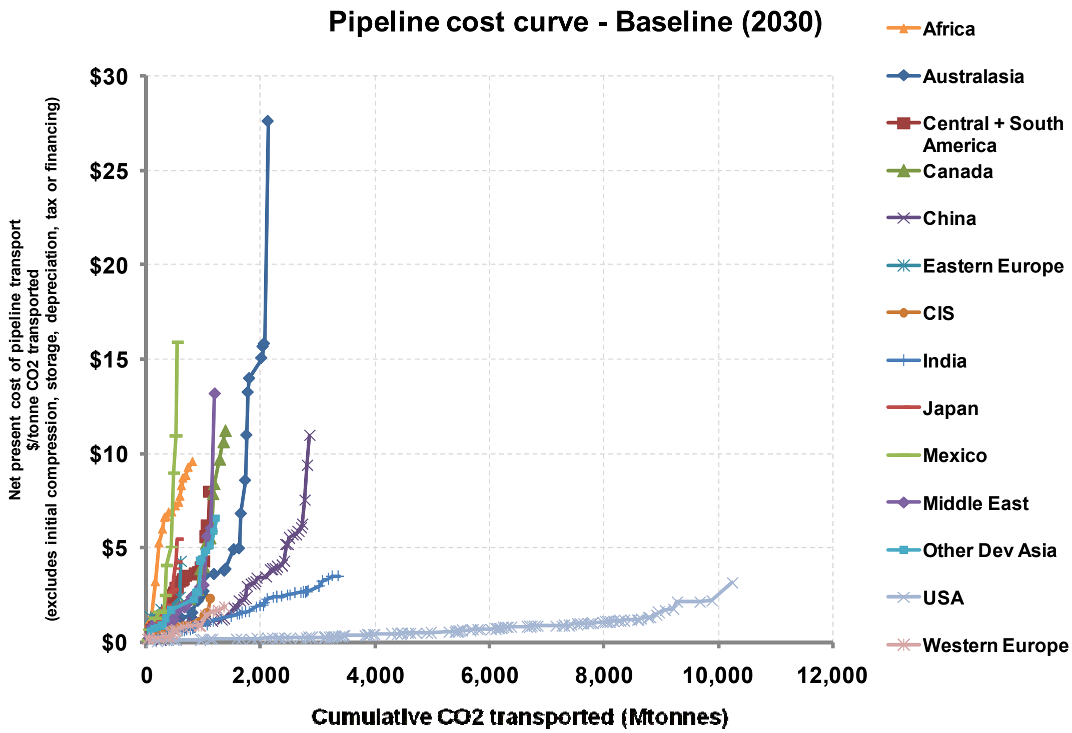


Figure 2 Marginal transport cost curve for baseline scenario for 2030 for sources and sinks connected via point-to-point networks. Each point corresponds to a specific source-sink combination.

- There is high potential to generate cost-effective CO_2 pipelines within the USA in 2030 in the baseline scenario.

- In most other regions, there are only a limited number of source-sink combinations in 2030 that have transport costs below \$5/t CO_2. As this demand is connected, the sink capacity is committed to these projects. The remaining combinations of sources and sinks involve more expensive pipeline choices, i.e. involving longer pipelines, routing offshore or through difficult onshore terrains, or connecting smaller sources.

1.4 Priorities for aquifer characterisation.

A major uncertainty in estimating CCS potential worldwide is huge uncertainty on storage potential. Further limited transparency and data sharing/availability inspire limited confidence in existing estimates of capacity in specific regions. This uncertainty directly inhibits optimisation of infrastructure. It will likely add costs in some regions, by increasing the risk premium or forcing the provision of expensive redundancy options. Investment in CO_2 pipeline infrastructure in some regions may be delayed until storage estimates are better substantiated.

For analysis in the context of this uncertainty, it was essential to develop a model that can deal with variations in sources and sinks. The databases for sources, sinks, demand and the priorities of the emerging CCS industry can be modified objectively, and the impacts quantified, through scenario-driven analysis. Storage capacities are extremely uncertain (even to within orders of magnitude). As an example, the network model was used to quantify the overall capacity and cost-effectiveness of CO_2 transport in selected regions for three scenarios of saline aquifer availability, keeping constant the storage capacity in giant gasfields and maximum CCS demand in a given year. The model therefore provided insight into the regions where urgent exploration of aquifer storage potential is required from a transport perspective.

Table 1 Ease of meeting demand for CO_2 transport in different regions with modelled storage capacities.

Region	Ability to meet Blue Map Demand in 2030 under baseline scenario	Ability to meet Blue Map Demand in 2050 under baseline scenario	Cost effectiveness of new pipelines required for 2030	Cost effectiveness of new pipelines required for 2050	Importance of aquifer storage in 2030 wrt baseline scenario	Importance of aquifer storage in 2050 wrt baseline scenario
Africa	High	Low	Low	Low	Low	High
Australasia	High	Low	Moderate	Low	High	High
Central + South America	High	Low	Moderate	Low	Low	Moderate
China	Moderate	Low	High	Moderate	High	Very High
Eastern Europe	Low	Very Low	Moderate	Low	High	Very High
CIS	High	Moderate	Moderate	Moderate	Very Low	Very Low
India	High	Very Low	High	Low	High	Very High
Japan	Moderate	Very Low	Moderate	Low	Very High	Very High
Middle East	Very High	Low	Moderate	Moderate	Very Low	Low
Other Dev Asia	Very High	Very Low	Moderate	Low	Low	Moderate
USA	Very High	Moderate	Very High	Very High	High	Very High
Western Europe	Very High	Low	Very High	Moderate	Low	Very High

Table 1 presents a qualitative summary of the regional analysis for the point-to-point network scenario with the illustrative capture demands, source locations and storage estimates used in this study. Most regions are able to meet the IEA Blue Map's CCS demand in 2030, using networks for which unit transport costs are below \$20/t CO_2 and mostly below \$5/t CO_2. As shown in Table 1, many regions struggle to meet the demand proposed for 2050, using the baseline scenario assumptions.

Approximately 80% of the 2030 Blue Map CCS demand is met worldwide in the baseline. The USA and Western Europe are particularly able to meet their respective demands with relatively low cost networks. Meeting the 2050 Blue Map demand is very challenging using the study's modelled baseline assumptions on the distribution of storage capacities. At a global scale, only 15.5% of the 2050 is met; in a 'high aquifer' scenario, where the modelled percentage of published aquifer capacities available for CO_2 storage is increased from 2% to 10%, the percentage of Blue Map demand met in 2050 increases only to 23%.

The principle uncertainty is on the available storage capacity in aquifers. Assuming CO_2 storage in depleted giant gasfields is possible at levels published in a recent IEA GHG study[2], the study identifies the aquifer storage capacities in Australasia, China, Eastern Europe, India, Japan and the USA as key uncertainties for meeting the 2030 demand. The study further identifies that the capacity and cost-effectiveness of transport in 2050 for Central and South America and Western Europe additionally depend to a large extent on the aquifer storage capacity.

In the baseline scenario, only 13% of worldwide sink capacity is committed for CO_2 storage in 2030 and 2050. This figure shows large regional variation, with Eastern Europe, Japan, Mexico and South Korea committing over 70% of their modelled total sink capacity for CO_2 storage. However, CIS and the Middle East, which together contribute nearly half of the global sink capacity, show very low utilisation of their sinks - this is because the majority of sinks are located close to each other, and far from most sources, and/or over difficult terrain such as mountains or desert.

[2] Poyry, Element Energy and BGS (2009) Role of depleted gasfields in CCS, for the IEA Greenhouse Gas R&D Programme, available at www.ieaghg.org

The network model provides metrics for the robustness of CCS planning for different regions by comparing whether the same sources and sinks are used across different scenarios. As an example, an important decision in the design in respect of capture ready policies is recognising that in waiting for a specific storage site to be validated, or rules and incentives for cross-border CO_2 transport to be agreed, some sources may delay planning for capture rather than risk developing assets that are then stranded.

The study reveals that uncertainties on assumptions on aquifer storage impact around half of all sources that are selected for CCS in the baseline scenario. Planning for CCS in 2030 for many sources is thus difficult in South Africa, Australia, China, India, Japan, Mexico, parts of Europe, and the USA. Extensive mapping of aquifers in these regions is required to better characterise total volumes and practical storage potential. Uncertainties on cross-border transport affect more than one in five sources. Where cross-border transport is required, independent verification of storage potential may be required (i.e. capacity estimates will need to satisfy stakeholders in both countries, not just the local geological survey).

If the full potential for economies of scale can be realised through the use of a few large pipeline diameters, integrated pipeline networks could reduce CO_2 transport costs and risks considerably compared to a series of point-to-point networks. Smaller emitters would benefit considerably from this. The network model identifies many examples in all regions where integrated CCS networks are more efficient. The average pipeline length saving inside integrated networks (when compared to the point to point networks they replace) is over 40%. Since not all sources are able to connect to integrated networks due to large distances and terrain factors, the overall length saving *across all source/sink combinations* is lower, at 20-25% in 2050.

In addition to the requirements to manage entry specification and flow, the principle issue for trunk pipelines for integrated infrastructure relates to improving the financial attractiveness through reducing risk. The phasing of risks and rewards, and the different hurdle/discount rates for the different investors involved, are critical in establishing the value of the CO_2 transport tariff.

The development of an integrated initially over-sized CO_2 pipeline infrastructure may influence the locations of future sources. This will clearly depend on the balance of economies of scale in CO_2 transport and potential diseconomies elsewhere (e.g. in electricity transmission or fuel supply infrastructure for power stations). The report recommends this is addressed through system-wide cost-benefit analysis.

1.5 Legal impediments and regulatory issues

Current legal frameworks have allowed the development of high pressure CO_2 pipelines in North America and Norway. Outside these jurisdictions, existing legal and regulatory frameworks are imperfectly designed or absent for supercritical or dense phase CO_2 pipelines. However, legal frameworks were developed and have now permitted the growth of high pressure natural gas pipelines in and across most countries. Some of the frameworks that would be required to allow CO_2 transport can and should be developed country-by-country through national processes. However, there are also international conventions and practices which may pose barriers for CO_2 pipeline infrastructure. A chapter summarises the key issues and provides recommendations on areas for IEA GHG to focus the efforts of stakeholders in developing solutions. The report also indicates areas where substantial progress has been made in reducing legal or regulatory barriers to CO_2 transportation.

The most important legal challenges identified in the study are:

1. International conventions that may curtail or even forbid cross-border CO_2 transport.
2. The time taken for planning and consenting processes.
3. Uncertain jurisdiction for CO_2 pipeline siting and regulation.

4. Conditions on financing, which may impose requirements above and beyond national and international laws.
5. CO_2 accounting mechanisms and incentives which may struggle with CCS projects involving networks with multiple participants and countries.

An analysis of legal and regulatory issues highlights the following recommendations for CO_2 pipeline regulatory aspects:

- Further analysis by the Basel Convention secretariat may be warranted in order to assess the effects of the Convention on the scope for trans-boundary movements of CO_2 in some jurisdictions. The EU, by way of the recent CCS Directive, has removed the Basel Convention requirements for shipment of CO_2 within and between EU member states by disapplying the Transfrontier Shipment of Waste Regulation.

- The London Convention and Protocol may pose a legal barrier to trans-boundary movement of CO_2 where it is to be stored in geological media under the seabed. The amendment proposed by Norway should be reviewed and adopted as soon as possible in order to ensure that the Protocol does not act as an impediment to cross-border CO_2 projects. This issue is pertinent for many regions, including the North Sea, Irish Sea, Mediterranean Sea, Black Sea, Caspian Sea, Persian Gulf, Gulf of Mexico, South East Asia, West Africa, and for the coasts of India, China, Australia, Japan, and Brazil where significant potential for sub-seabed storage potential exists. Ratification of the OSPAR amendment is also needed to ensure projects can go ahead in the North East Atlantic zone.

- Rapid development of national regulatory regimes for CO_2 transport is required in order to ensure clarity over the necessary regulatory oversight applicable to new CO_2 pipeline developments.

- CO_2 pipelines must be constructed with due protection of human health, society and the environment. In developed countries, these will likely be determined by national and regional planning procedures. In the case of developing countries, these may take the form of proxy regulations as imposed by international lenders. In all cases, approvals need to strike a balance between the need to protect people and the environment, and the impending need for rapid deployment of CCS to mitigate the effects of climate change.

1.6 Lessons from the oil and gas industry on developing pipeline infrastructure.

The oil and gas industry has used pipelines for transporting chemicals for more than one hundred years. A review of major pipeline infrastructure investment to date reveals that very large natural gas pipelines spanning multiple countries - including pipelines that are over 3000 km onshore and over 1000 km offshore - have been built and financed successfully using a diversity of business models and ownership/financing structures. Integrated infrastructure, including tree-and-branch or hub-and-spoke designs, are also present in all countries where it is required to connect multiple points of supply and demand. Pipeline developers seek to minimise unit transport costs by optimising scale and minimising unfavourable terrains. Risks are often mitigated through phased growth and careful design of contracts.

Investment in the energy industry, and including the largest oil and gas pipelines is frequently procured through project finance. Project finance is a highly structured source of finance, where projects have limited or no recourse to owners. As such revenues from the project are fully expected to pay back debts and provide dividends to equity partners. The debt structure and contractual arrangements are carefully tailored for the risks associated with each specific investment. Oil and gas pipelines represent a relatively small but stable part of the overall market for project finance. Notable themes for project financing of large oil and gas pipelines have been:

- Investment of several US$ billion have been arranged for a number of pipelines, including pipelines spanning thousands of kilometres and/or crossing national borders or difficult terrains.

- A wide mixture of debt:equity ratios are possible. Debt financing, being cheaper, is preferred but lenders rely on higher levels of commercial certainty. Equity sponsors always bear first risk of loss. For both equity and debt sources, funding is usually arranged through a consortium. This helps to reduce the risk for any individual investor and can also ensure the interests of different stakeholders are represented.

- National governments, or international organisations such as the World Bank and partners, frequently facilitate financing. This can be either through direct investment (possibly through state-owned industries which take an equity share) or by providing guarantees. This occurs where the state has a compelling strategic interest in the pipeline or in emerging markets where business risks are higher.

- Three classes of project developer, or ‘Promoter’, are common. Upstream promoters (in the sense of oil and gas extraction) develop pipelines to provide a market for produced oil or gas. ‘Downstream’ promoters seek to provide a source of hydrocarbons for power stations or industrial plants. ‘Mid-stream’ projects, where pipelines are built to link supply and demand are rarer, and are most at risk from changes in the business plans at either end. Risks for mid-stream projects are reduced when supply or off-take contracts and tariffs are arranged in advance. However risks for pipeline sponsors are increased when either supply or demand is also ‘greenfield’, i.e. itself requires project financing.

- Efficient pipeline investment is promoted to different extents in different regions. Guiding philosophies are largely the product of historical and cultural biases. Priorities will depend strongly on geography and existing conventions. Measures that promote efficient pipeline investment include defining transportation capacity a point-to-point basis to provide clear price signals, mandating open seasons to ensure efficient and timely expansion of the network, and incorporating pipelines into existing planning rules to avoid distorting incentives. The efficiency of integrated networks is improved through an obligation on pipeline owners to provide taps. This reduces barriers for new entrants and promotes competition on price. Once built, the most efficient use of capacity is promoted by unbundling ownership from capacity, setting tariff structures in line with variable costs, and enabling secondary (spot and future) capacity trading so that parties who most value capacity can gain access to it. These steps allow a market price for capacity to emerge.

1.7 Challenges for financing CO_2 pipelines

By far the most important challenge facing developers of CO_2 pipelines worldwide is the absence, in most locations, of a long-term attractive value in abated CO_2. A generic exception is where CO_2 transport is for enhanced hydrocarbon recovery[3]. The absence of sufficient financial incentives is a systemic issue facing all aspects of CCS. The issue is well documented elsewhere and is outside the scope of this report.

Where investors can fully capture the value of abated CO_2, a fully competitive market should promote efficient investment. Current CO_2 prices in existing trading schemes are far from sufficient to support the large investments required to adopt CCS. At the present time investors have very low visibility as to the scope and price of abated CO_2, and in many regions there is no effective CO_2 price. Uncertainties on CCS technology deployment are large. Therefore where national governments have ambitious CO_2 targets, but the market fails to provide sufficient reward for private investors to invest, these governments may need to step in to provide some support for pipeline investment. There are examples from elsewhere within the low carbon energy sector where dispersed commercial actors required leadership or co-financing from governments or other public institutions to develop critical supporting infrastructure.

Certain emission reduction accounting guidelines may deter the development of CO_2 pipeline networks by imposing rigid boundaries on emission accounting requirements, for example, under the Kyoto Protocol's clean development mechanism. In broader terms, there is also future scope for refining fledgling emission reduction accounting guidelines for CCS in order that they more clearly define accounting requirements for trans-boundary CO_2 pipelines.

1.8 The transition to large-scale pipeline infrastructure

Figure 3 illustrates four compelling configurations for CO_2 transport infrastructure required to connect clusters of multiple sources to multiple sinks. These options are A) independent point-to-point pipelines, B) shared integrated pipeline infrastructure; C) independent pipelines that share common rights-of-way and D) shipping.

[3] Enhanced hydrocarbon recovery is currently the subject of a separate study for IEA GHG.

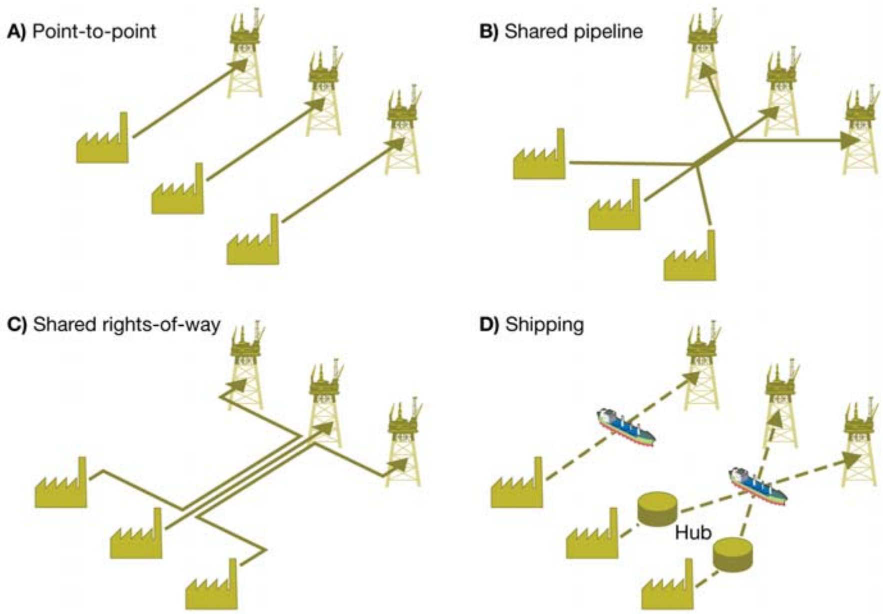


Figure 3 Schematic of options for transport network topologies. A) Point-to-point; B) 'Shared' or 'Integrated' pipeline; C) Shared rights-of-way; D) Shipping

For a simple system with two sources connected to a common sink, the discounted cashflow analysis confirms the following decreasing order of importance for key drivers:

- The longer the pipeline length (or more challenging the terrain) the higher the tariff required.
- The smaller the absolute capacity the higher the tariff required.
- The higher the weighted average cost of capital (or discount rate) the higher the tariff required.
- The longer the economic lifetime and loan period the lower the tariff required.
- The longer the delay between construction and operation, the higher the tariff required (N.B. excludes payments for CO_2 emissions in the gap)
- The longer the construction period, the higher the tariff required (N.B. excludes payments for CO_2 emissions in the delay).

These drivers have similar effects for integrated and point-to-point infrastructure. In a limited number of cases transport costs can be reduced by encouraging capture from sources near to sinks. However the flexibility to do this may be constrained by diverse forces. The DCF analysis suggests that the priority for public intervention has to be to reduce the economic risks and thereby reduce the cost of capital for investment in pipeline infrastructure. This could be achieved through development of stable well-designed long-term regulatory and economic frameworks, as well as encouraging social and political awareness and acceptance of CCS where appropriate.

The high level analysis shows that the factors which favour integrated pipeline infrastructure over independent point-to-point pipelines are (in order of decreasing importance):

- Geometry, with only smaller source-sink (or hub) -source angles favouring integrated infrastructure.
- Relative capacity – small sources benefit substantially from sharing infrastructure with a larger source. This can increase costs for the larger source in some scenarios, so that careful tariff structuring may be required to ensure utilisation.
- Close phasing of sources, with very short delays between the first and second source connecting to the same network.

Further work is required to quantify the 'option' value for sources from having a transport network ready for use.

With immense uncertainties over capture and storage potential (including the potential for enhanced oil recovery), the inherent specificity of pipeline routes, and with widely different geographical and economic circumstances, it is extremely difficult to make robust long-term decisions now on a regional or national pipeline networks for CO_2 that successfully balance technology maturity, flexibility, scalability, costs, risks, benefits, and permitting challenges. Any public investment decisions must also account for the implicit messages on perceived confidence in CCS sent to stakeholders by public investment in point-to-point or 'oversized' infrastructure.

In locations where the case for integrated infrastructure is not yet robust, it may be necessary for infrastructure deployment to proceed stepwise in the 2010s, gaining experience from small-scale point-to-point pipelines (or shipping) before very expensive integrated international systems are developed in the 2020s and later to connect multiple sources and sinks. In regions where uncertainty over demand or storage capacities continues to remain extremely high, point-to-point networks may be the preferred option to reduce the risk of stranded assets. If this is the case, it may still be possible to capture many of the benefits of integrated infrastructure by ensuring that rights-of-way are reserved to permit multiple pipelines along the same route. This would reduce or eliminate the planning and consenting risks and timescales for subsequent projects, without requiring economically inefficient or excessive up-front investments.

2 INTRODUCTION

Carbon dioxide capture, transport and storage is part of a portfolio of climate change mitigation options available to policy makers and industry. A key component of the cost-effective evolution of the technology is providing low cost large scale transport of CO_2 which encourages widespread deployment. Pipelines and ship transport represent the two most cost-effective means of transporting CO_2 over long distances. Ship transport is expected to provide significant flexibility, and could play an important role for projects of smaller sizes or short/uncertain durations or where terrains favour this option. However the majority within the CCS industry agree that the most of cost-effective CO_2 transmission infrastructure for large projects, potentially spanning multiple decades, would be provided by pipelines. Where pipeline infrastructure designs, financing and regulation are optimised, the safety, scale, cost-effectiveness and public acceptance of transporting CO_2 are improved, improving the likelihood that CO_2 emission reductions can be achieved through CCS.

The major challenges for CO_2 pipeline transmission infrastructure are diverse and include:

- Potentially long distances or arduous terrains that pipelines must cross to connect source and sink.
- The physico-chemical properties of CO_2 streams derived from capture processes.
- Balancing and coordinating the capture, compression, pipeline and sink network technical specifications.
- Optimised network design to meet short and long-term objectives, including financing, increasing capacity over time and flexibility.
- Business and finance models consistent with uncertainties in CCS demand, high capital expenditures, long payback periods, and the limited visibility on future CO_2 prices.
- Legal barriers, such as restrictions on CO_2 transport across international borders.
- Regulatory models and variations in regulators and regulations between jurisdictions.

Given the diversity and scale of these challenges, they may slow down the building of pipeline infrastructure. This might become a major barrier to the widescale implementation of CCS, and increase the costs of meeting CO_2 stabilisation targets. However, most of the challenges described above for CO_2 transport infrastructure have been met by other major transport infrastructure programmes. Notably integrated transport networks have been financed and constructed in virtually every country, to move fluids, people or waste materials safely, and across national borders and diverse terrains.

In March 2009 a team led by Element Energy Ltd was commissioned by IEA GHG to undertake a study to identify the challenges and opportunities for CO_2 pipeline infrastructure. The approach agreed between Element Energy Ltd and IEA GHG for the study comprises a mix of literature review and quantitative modelling. This document constitutes the final report from the study. The chapters are arranged in the following order:

- Section 3 seeks to answer *how* CO_2 pipelines should be designed, and what are the key gaps in current understanding from a health, safety, environmental or engineering perspective.

- Section 4 describes a model developed to optimise, on the basis of transport economics and feasibility, the matching of sources and sinks at a worldwide level for the years 2030 and 2050. This section also describes the key input databases and assumptions used in network design for the scenarios that are explored.

- Section 5 presents the results from source-sink matching for four scenarios. The results are presented as (i) maps of possible locations for pipeline infrastructure in 2030 and 2050, and (ii) as marginal transport cost curves. A baseline scenario is defined, and the impact of aquifer availability and the cost savings for centrally integrated pipeline infrastructure on transport costs are quantified for different regions.

- Section 6 identifies potential international legal and regulatory barriers that could delay the permitting or financing of CO_2 pipelines.

- Section 7 draws on lessons from the financing of oil and gas pipelines to identify possible financing arrangements and structures for economic regulation for CO_2 pipelines. Additional challenges for financing CO_2 pipeline infrastructure are identified.

In addition three appendices are provided:

- The first appendix provides a more technical analysis of the engineering challenges for CO_2 pipelines.
- The second appendix lists assumptions and equations used for the source-sink selection, cost modelling and sensitivity analyses within the study.
- The third appendix explores the impacts of selected drivers on the costs of integrated and point-to-point pipeline infrastructure.

3 ENGINEERING CHALLENGES FOR PIPELINES TRANSPORTING CAPTURED CO_2

Pipelines have been used to transport gas, dense and supercritical phases of CO_2, sometimes over long distances, for many years. This chapter provides an overview of the key engineering challenges for transporting *captured* CO_2. The chapter considers:

- how CO_2 phase can be controlled
- how corrosion and hydrate formation can be avoided by managing water levels
- how safety features can be built into the pipelines themselves or in route selection.

A technical analysis is presented in Appendix 1.

3.1.1 Management of CO_2 phase

As shown in the phase diagram for CO_2 in Figure 4, the operating pressures and temperatures determine the phase of pure CO_2. The phase diagram identifies the 'critical point' at 74 bara, 31°C.

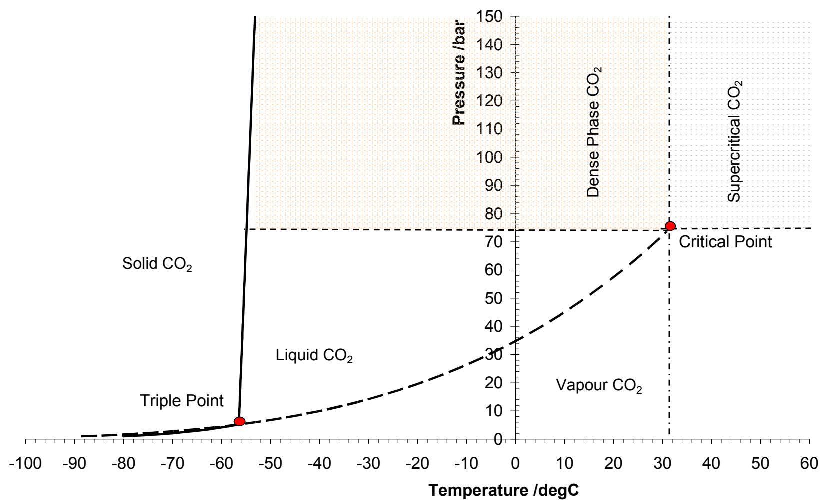


Figure 4 : The phase diagram for pure CO_2 identifies the phase of CO_2 at any given temperature and pressure. For pipeline transportation the transported fluid is kept either on the liquid, or on the vapour, side of the vapour/liquid line running between the triple and critical points, but is not allowed to cross it.

Therefore developers and regulators may find it hard to agree on an appropriate minimum pressure. Sources may seek to provide the minimum levels of CO_2 purity and pressures possible, as this will reduce their capture and compression costs. Limited modelling to date demonstrates that impurities in the CO_2 from oxyfuel and pre-combustion capture processes in particular increase the potential for mixed phases, necessitating a higher minimum pressure. Combinations of impurities (e.g. from different sources) could together raise the critical pressure more than that from a component in isolation. Pressure changes in CO_2 from intermittent sources will need to be very carefully managed. Intermittency has not been a significant issue for CO_2-EOR pipelines where flow is relatively uniform, but requires more examination – it may be more challenging with industrial and power sector sources of CO_2[4].

[4] As an example, high renewable power penetration may mean that the back-up fossil power plant would provide a highly variable supply, possibly with short notice. Element Energy (manuscript submitted) Role of CCS in the Gas Power Sector, for the UK Committee on Climate Change.

The outcome of this lack of understanding could be that pipeline minimum pressures and start-up or shut down procedures do not sufficiently avoid two phase flow, so that pipeline damage results. Insufficient attention to the impacts of potential impurities from CO_2 streams from different sources, or inconsistent standards, may mean that early pipelines are unable to connect to sources that adopt CCS subsequently – necessitating multiple independent pipelines, rather than integrated networks with multiple sources. Alternatively, additional investment at source is required to meet the pipeline input specification. A pragmatic and potentially cost-effective solution may be to operate the pipeline with at higher pressure (e.g. an additional 10-15 bar) to reduce the potential for mixed phase flow, and/or provide additional pumping stations at intermediate points along the pipeline.

Improving understanding on the impacts from multiple impurities on phase behaviour and flow properties of CO_2 will help regulators and developers to specify pipeline entry pressure, temperature and composition specifications for integrated networks that balance the competing requirements to avoid two phase flow, reduce costs for capture, compression, and transport, and maximise overall CO_2 abatement. There has been some examination of these issues by industry and regulators, but to date the information in the public domain is relatively limited. Therefore this study recommends that this more detailed engineering analysis of the costs, benefits and impacts of different CO_2 entry specifications covering both pipeline engineering and issues related to capture and compression is brought into the public domain.

3.1.2 Management of corrosion and hydrate formation risk through removal of water.

The presence of free water[5] (as opposed to dissolved water) in the CO_2 stream may cause corrosion of the pipeline steels and/or lead to hydrate formation in the pipeline. All of the operational CO_2 transmission pipelines are manufactured from plain carbon steel which is essentially non-corrosive in pure CO_2. Trace water dissolved in the CO_2 stream is not a significant problem. However, in the presence of *free* water, highly corrosive carbonic acid is formed and it has been reported that carbon steel can corrode at rates of more than 10mm/year in wet pure CO_2 (Seiersten and Kongshaug, 2005). Alternative steels, such as stainless steel are resistant to corrosion by carbonic acid but are much more expensive than carbon steel.

Hydrates are solid compounds with similar properties to ice; consequently they can block the pipeline and plug or foul other equipment such as heat exchangers. In order for hydrates to form in a CO_2 pipeline there must be the required combination of pressure and temperature and a sufficient amount of water present. Under CO_2 pipeline operating pressures, and with certain water contents, it would be possible for hydrates to form at around 10-11°C (Fradet *et al* (2007), Wallace (1985)), and therefore there is a requirement to control water levels.

Water is produced by combustion of fossil fuels in air or oxygen, for post-combustion on heating the solvent, and from many industrial processes that also produce CO_2. There is a consensus that this water must be removed prior to pipeline transportation, and there exist a number of effective drying technologies and processes, however there is no general consensus on what the maximum final level of water should be.

The specification of an acceptable level of water in the pipeline is dependent on the solubility of water in the fluid at the operating temperature and pressure. As illustrated in the Appendix, the amount of water must be significantly less than the maximum that can be dissolved in the CO_2. An indicative limit could be taken as 60% of the minimum solubility achieved by pure CO_2 at the design temperature, e.g. 200 ppm at 4°C, although opinion may differ on what

[5] Free water is water that is not dissolved in the CO_2 stream.

constitutes an acceptable margin of safety[6]. Chemical impurities in the CO_2 stream may affect when hydrates form and the nature of the hydrates that form. In some locations for hydrocarbon pipelines small amounts of inhibitors are added to reduce the risk of hydrate formation, although this may be subject to regulatory approval[7]. There is very limited understanding of the appropriate margin of safety required to eliminate the risk of hydrates.

Other impurities in the CO_2 stream can change the drying requirements (and thus costs). There is only a limited amount of data available and more laboratory experiments are required to determine the solubility of water and potential for hydrate formation in CO_2 containing the types of impurities to be expected from capture over a range of operating temperatures and pressures. Until this data becomes available there is a risk that developers and regulators will make inappropriate drying specifications. Insufficient drying could lead to corrosion of pipelines and joints from carbonic acid, or mechanical damage from hydrates. In contrast a conservative approach may raise drying costs unnecessarily. In turn this could raise overall CCS system costs and reduce the likelihood that sources will connect.

It is therefore recommended that studies are undertaken

(i) on the propensity for free water and hydrate formation in the presence of likely impurity levels in CO_2 streams from capture.
(ii) on the costs, benefits and impacts of different drying processes and dryness specifications on capture and compression.

The benefit of these studies would be to speed up decision making by sources, pipeline developers, health and safety regulators, and regulators keen to ensure maximum accessibility of CO_2 pipelines.

3.1.3 Minimising the risk and impacts for leakage through use of appropriate design factors, materials, safety features and routing choices.

Leakage from CO_2 pipelines could pose a danger to those nearby and to the pipeline infrastructure itself. Unlike natural gas, CO_2 is heavier than air and diffuses slowly. Therefore CO_2 from a leak may accumulate in particular areas (e.g. depressions in the ground) and lead to asphyxiation. With the unusual phase behaviour of CO_2, there is the potential for supercritical or dense phase CO_2 to change phase as the pressure is reduced, leading to a sudden temperature change. If the CO_2 solidifies as it escapes, it could fall as a CO_2 snow. This may endanger those nearby and create a stress on the pipeline. Finally any impurities within the CO_2 stream may themselves have exposure and environmental limits which need to be considered.

CO_2 pipelines for enhanced oil recovery offer limited insight as these typically run in sparsely populated and relatively flat open countryside in North America. In contrast pipelines for CCS in Europe and elsewhere will likely cover a range of terrains, and include crossings or areas of significant population density where risks of accidents may be higher and the impacts (e.g. asphyxiation[8]), may be more severe.

Assuming sufficient understanding of the effect of a leak, design codes can be set to mitigate these risks from leakage, and operators will make choices on materials and routing

[6] Effect of Common Impurities on the Phase Behaviour of Carbon Dioxide Rich Systems: Minimizing the Risk of Hydrate Formation and Two-Phase Flow", Chapoy, Burgass and Tohidi, Hydrafact/Heriot-Watt University, Austell and Eickhoff, Progressive Energy, presented at the Oil and Gas Conference and Exhibition, Aberdeen, 8-11th September 2009

[7] Some regulators may forbid the addition of chemicals to CO_2 streams.

[8] To date there have been no deaths from CO_2 release from CO_2 pipelines. The experience from Lake Nyos where a large cloud of naturally occurring CO_2 suffocated 1,700 people and 3,500 livestock in nearby villages is unlikely to be relevant as low pressure releases have different flow characteristics to high pressure releases.

accordingly. However, there is limited experimental data gathered on the dispersion of CO_2 from a leak in the public domain. There is also limited information on the costs, benefits and impacts of different strategies for minimising leakage and pipeline failure. This makes it difficult for regulators to set the appropriate design factors[9] (e.g. for pipeline wall thicknesses, concrete sleeves, sizes of exclusion zones, frequency of block valves and crack arrestors, – see appendix). It is also difficult to reassure the public in areas which may potentially be affected. This may slow down permitting. There is a risk that, in the face of uncertainty and limited experience, some regulators may adopt design codes that offer insufficient protection or that may be too onerous for developers, or that regulators request further information that is too time consuming or expensive for individual CCS project developers to provide.

To accelerate the potential screening of alternative routes and design specifications, it is recommended that

(i) greater experimental validation of the models for accidental CO_2 release is obtained, and subsequently
(ii) standardised models are developed for CO_2 leakage and design criteria that can be used by developers and regulators in diverse terrains, accelerating the potential screening of alternative routes and design specifications.

3.1.4 Pipeline reuse

In a limited number of cases, an existing pipeline has an appropriate capacity and location to connect source and sink. Where pipeline integrity is well established, it may be possible to reuse existing natural gas pipelines for transporting CO_2, providing that use with CO_2 meets the appropriate design codes. In these favourable, but niche, cases, the reuse of existing pipelines for CO_2 transport may reduce the time and costs to deploy CCS.

Restrictions on availability include start dates that are too late, inappropriate capacity, limited remaining lifespan, limited warranty for alternative use, decommissioning practices, or poor location. Assuming water is removed appropriately from the CO_2 stream, the two main choices are in terms of operating pressure (consistent with existing materials, rights of way) and carefully examining the specifications for minor components such as valves and O-rings to ensure these are fully compatible with CO_2. Recent studies have found too little information in the public domain to quantify the potential for pipeline reuse on a global basis, although reuse potential has been identified opportunistically[10].

[9] The pipeline design codes dictate the maximum design stress of a pipeline by specification of a ‘design factor’, defined as the ratio of the hoop stress to the SMYS (Specified Minimum Yield Stress) of the pipe material. The design factor is used to control the level of stress in a pipeline. The higher the design factor, the higher the allowable stress in the pipeline. Most pipelines around the world have a maximum design factor of 0.72, although there are some pipelines operating at higher factors. The design factor minimises the risk of pipeline failure and therefore is assigned in relation to the location of the pipeline and the substance being carried. Design factors for a given pipeline are reduced from the maximum according to the proximity to people and the hazardous nature of the transported fluid.

[10] Two proposals in the UK involved the reuse of an existing hydrocarbon pipeline for low pressure (i.e. gas phase) CO_2 transportation, one onshore (St.Fergus to Avonbridge, Ofgem and National Grid, 2009) and one offshore (BP/SSE, 2006). However there is limited engineering description for these proposals in the public domain

Table 2 Overview of Risks, Mitigation Strategies and Challenges for CO_2 pipelines

Technical issue	Risk	Mitigation Strategies	Recommendation
Unusual phase properties of CO_2	Mixed phase flow Instability in physical properties near phase boundaries	Operate in single phase. CO_2 shippers to insist on gas composition requirements being met Minimise opportunities for leaks and sudden changes in conditions. Plan appropriate start up and shut down procedures. Block valves to isolate segments of pipeline	Study of impact of impurities and impurity removal to support specifications for CO_2 entry to pipelines and networks.
CO_2 dissolved in water is highly corrosive to carbon steel	Corrosion of pipeline or joints increases risk of failure.	Ensure all sources adopt rigorous drying facilities Use corrosion resistant materials (including for minor components)[11].	Agreement on CO_2 entry specification water levels
High density of CO_2	In the event of a leak, CO_2 could accumulate and lead to asphyxiation	Use of conservative design factors. Minimise potential for leakage through material and design selection. Route away from areas of population. Increased experimental testing and validation of CO_2 dispersion models Avoid CO_2 pipelines running through valleys, depressions if possible.	Support experimental testing of CO_2 pipeline failure and CO_2 dispersion used to build standardised models.
New pipelines are expensive and time consuming to permit, therefore seek to reuse existing pipelines	Concern over pipeline and suitability for CO_2 transport Restrictions on capacity, timing, location and safety measures.	Operate existing pipelines in gas phase (i.e. low pressure) to minimise requirements to manage pressure.	Information from specific engineering studies pipeline reuse is monitored to identify general lessons.

[11] Use of expensive stainless steel is unlikely to be economic except for very short connection lines.

4 A MODEL FOR OPTIMISING CO_2 SOURCE-SINK COMBINATIONS

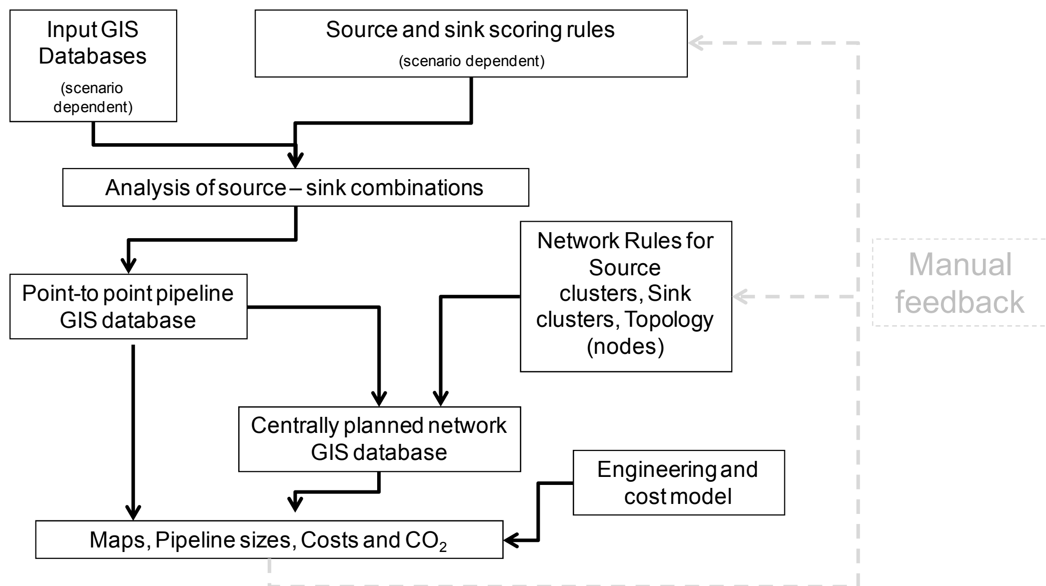


Figure 5 Outline of source-sink network and cost model

4.1 Source Sink Matching

With several thousand sources and sinks, there are potentially millions of theoretical source-sink combinations. A screening process is therefore required to identify plausible source-sink matches. The screening process is very similar to that used in the recent IEA GHG study of gasfield storage capacity, with three key improvements.

1. The CCS target is dictated by the IEA Blue Map CCS demand by country in 2030 and 2050. The requirements by region are shown below.

2. In addition to giant gasfields, the study includes aquifers. Worldwide, the data on aquifer storage is weak. There is not enough data worldwide to support generalizing the ratio of practical storage capacity to theoretical storage capacity, and most published data do not clearly and consistently provide site-specific breakdowns of capacity or define capacities in ways that allow the data to be compared on a like-for-like basis. A number of mapping exercises are underway in some parts of the world, resulting in significant changes to capacity – so that estimates published as recently as five years ago are becoming out of date reflecting the growth in understanding of opportunities and constraints. It may be some time before estimates for storage capacity stabilise. Following another source[12] a value of 2% of published capacity actually available was used for the baseline scenario. The substantial reduction is intended to reflect a broad assumption that a variety of technical, regulatory, and economic and other constraints may restrict the availability of sinks. Importantly the storage values are used for illustrative purposes only and do not reflect any endorsement of regional capacity estimates by the authors or IEA GHG. A high aquifer scenario was also defined where the corresponding percentage assumed was

[12] BGS assumed this value for the 2009 Scottish Carbon Capture Consortium study "Opportunities for CO_2 storage around Scotland"

10%. Table 10 in the appendix presents the published and modelled assumed practical storage capacities. Within regions identified in the IEA GHG aquifer study, random sampling was used to generate representative injection points for aquifer storage. It is assumed that sufficient sink screening has been conducted to allow all sinks in the database to be used from 2030, with the exception of those gasfields with Close of Production dates after 2030 which are assumed to only be available for CO_2 storage for 2050.

3. The weightings for capacity and proximity are modified and also include some terrain restrictions and terrain weightings. The most notable restrictions are to reduce or eliminate the potential for pipelines crossing mountain ranges or very deep water. The degree to which terrain weighting is used to choose source-sink combinations is calibrated manually on the basis of consistency with historical routing of pipelines[13].

4.2 Modelling Inputs

Five databases form important inputs to the model:

1. The IEA GHG Sources Database provides information on the locations, types and amounts of CO_2 sources worldwide[14].
2. The IEA GHG Gasfield Storage Capacity study provides information on which large gasfields will be available, when, at what theoretical storage capacities worldwide[2].
3. The IEA GHG Aquifer study estimates possible storage capacities for different regions.This is supplemented with data from the North American NATCARB atlas where possible[15].
4. The IEA's ETP Blue Map demand provides a country-by-country breakdown of likely CCS demand in 2030 and 2050[1]. This is listed in Table 3.
5. Geographical Information Service (GIS) databases of terrains.

In addition, a simplified database of pipeline engineering costs, including terrain and regional cost factors was prepared drawing on information within IEA GHG's pipeline cost calculator[16].

The sources database identifies considerable heterogeneity in the location of the largest emitters, as shown in Figure 6 below. In some regions many large sources are closely clustered, leaving large areas with few sources. Conversely, there are also examples in most countries of sources that are relatively isolated.

[13] e.g. as identified in http://www.theodora.com/pipelines/world_oil_gas_and_products_pipelines.html
[14] See http://www.ieaghg.org/
[15] http://www.natcarb.org/
[16] AMEC (2009) Updated calculator for CO2 pipeline systems, Report 2009/3 published by the IEA Greenhouse Gas R&D Programme.

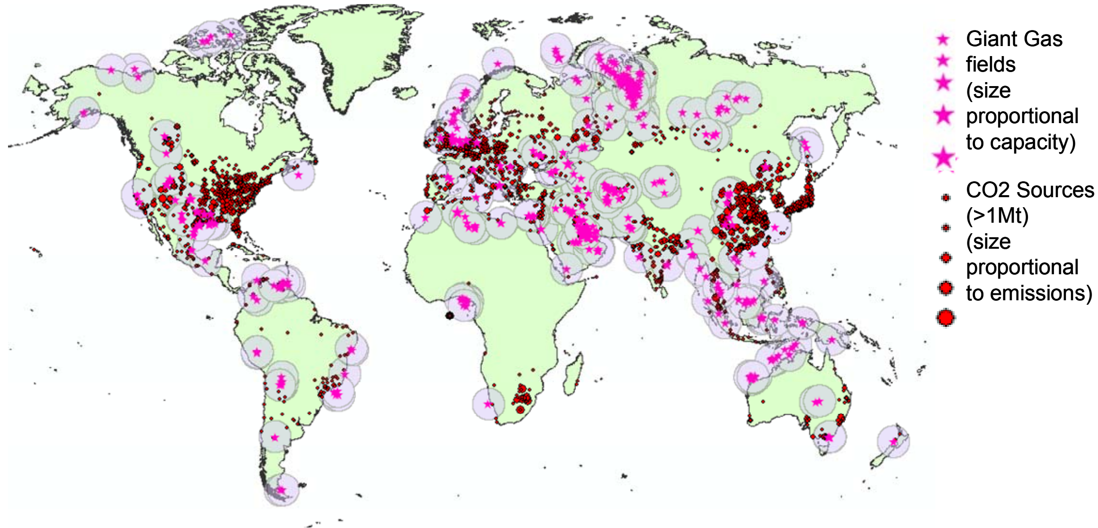


Figure 6: Database of sources and giant gasfields from IEA GHG (2009) CO2 storage in depleted gasfields. Gasfield storage capacity is denoted by a pink star. Red circles indicate the locations of CO_2 sources (> 1 Mt CO_2/year).

Figure 6 also shows the location of giant gasfields (loosely defined in terms of CO_2 but approximately those gasfields with storage capacity greater than 100 Mt CO_2). The locations and capacities of these fields were identified in the recent IEA GHG study on CO_2 storage in depleted gasfields.

Aquifers are, in general, more poorly characterized than hydrocarbon fields. The recent IEA GHG study on aquifers[17] provides estimates for worldwide theoretical storage capacities and this is used here to provide some consistency with other IEA GHG reports. Ranges spanning several orders of magnitude for storage capacity have been published for many regions. The assumptions used for aquifer storage are detailed in the appendix. With the focus of this study on pipeline transportation, these assumptions are only intended as a starting point for scenario analysis. Some newer data for the US, Ireland and the Northern and Central North Sea were used as referenced in Appendix 2. The total published storage capacity modelled is 9,496 Gt CO_2. The actual storage capacity available for storage is likely to be much lower for technical, commercial, and legal reasons, however there is insufficient data to quantify this for each region. Instead, three scenarios for aquifer storage are modelled in this study. In the 'baseline' scenario, 2% of the published storage capacity is modelled as available to store CO_2. In a 'high aquifer' scenario, 10% of the published storage capacity is modelled as available. The scenarios are intended to be illustrative only. Finally a scenario where no aquifer storage is available is also modelled, i.e. only giant gasfields are used for storage. Storage in oilfields (with or without enhanced oil recovery) is out of scope of this report and oilfields are not modelled.

There is, to our knowledge, presently no global dataset of likely injection points for CO_2 storage in aquifers. Given the wide distribution of these globally, a convenient and representative method of determining possible pipeline routes and costs is through random sampling within the prospective areas (modelled as polygons within GIS) identified in the IEA GHG and related studies. It is stressed that the exact location of the injection 'hubs' modelled is an output of the sampling algorithm within GIS and not a verified injection point.

17 IEA GHG Report 2008/12 "Aquifer Storage – Development Issues" available at www.ieaghg.org

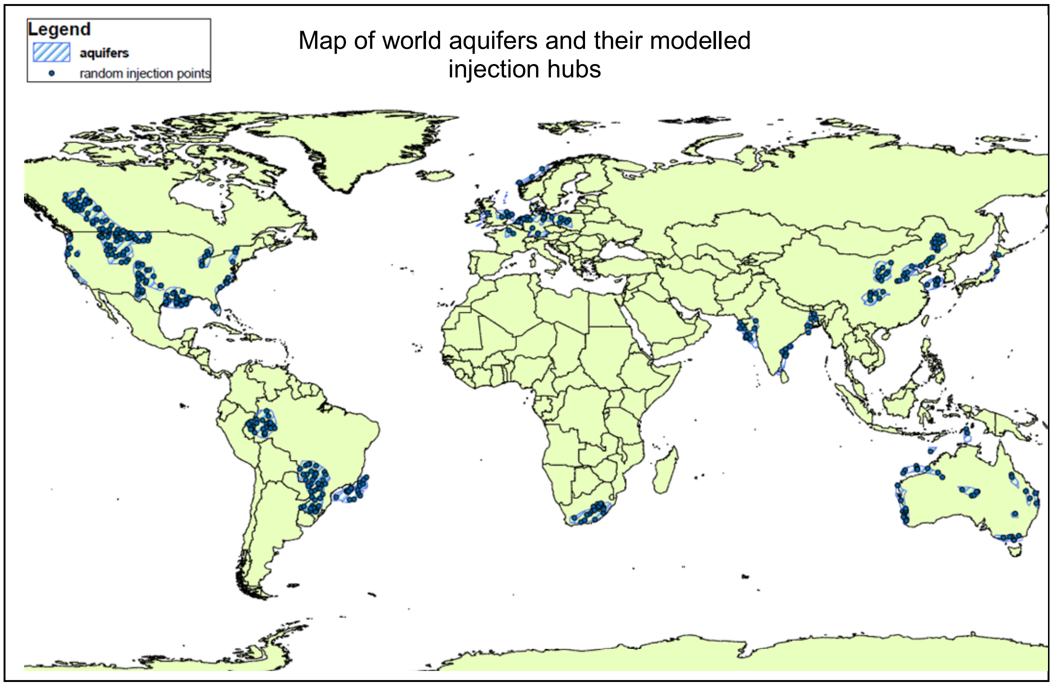


Figure 7: Map of world aquifer storage areas (light blue polygons) used in this study, showing injection hubs (dark blue circles) obtained by random sampling. Hubs are the focus for a distribution network to individual injection facilities and wells.

A number of possible regional scenarios for CCS demand have been put forward, but only a limited number of studies have examined global CCS deployment in a consistent format. At the request of IEA GHG, the IEA 2008 ETP Blue Map targets for CCS deployment in 2030 and 2050 have been used to provide upper limits on CCS demands[18]. These have been disaggregated to provide CCS uptake estimates for a limited number of regions as shown below.

Table 3 Blue Map CCS demand in Mt CO_2/year transported by region for 2030 and 2050 based on IEA's 2008 ETP analysis.

IEA Region	2030	2050
Africa	40	903
Australasia	129	353
Central+South America	52	476
Canada	148	574
China	307	2207
Eastern Europe	91	397
CIS	45	455
India	165	1153
Japan	42	129
Mexico	89	230
Middle East	60	505
Other Developing Asia	62	1093
South Korea	12	72
USA	495	1100
Western Europe	65.7	449.9
Total Mt/year	1,802	10,097
Implied required storage capacity for 20 year projects/Gt	36	202

Given that the total sink capacity shows large variation between regions, the stated Blue Map demands are harder to meet in some regions than in others. Australasia, Western Europe and the USA can store 20 years' worth of the 2030 Blue Map demand by using only 10% of their respective total sink capacities. However, Eastern Europe and Japan are unable to store 20 years of the 2030 demand due to insufficient capacity with the modelled capacity. Other regions, such as China have a small excess capacity, so although they can technically meet the 2030 Blue Map target, doing so is likely to require costly pipelines, since the majority of the regions' sinks must be connected.

4.3 Cost model

A straightforward cost model for transmission pipeline infrastructure is developed that allows a range of pipeline network architectures to be compared and contrasted. The approach taken draws on a simpler, minimum number of key input parameters consistent with available data and requirement to screen several thousand source-sink combinations in different scenarios efficiently.

[18] Since the preparation of this report, the IEA have published their CCS Technology Roadmap (available at www.iea.org) with revised demand. Although the total CCS demand for 2030 and 2050 remains comparable, there are some differences in the distribution of CCS demand between regions.

The model is outlined in the figure below.

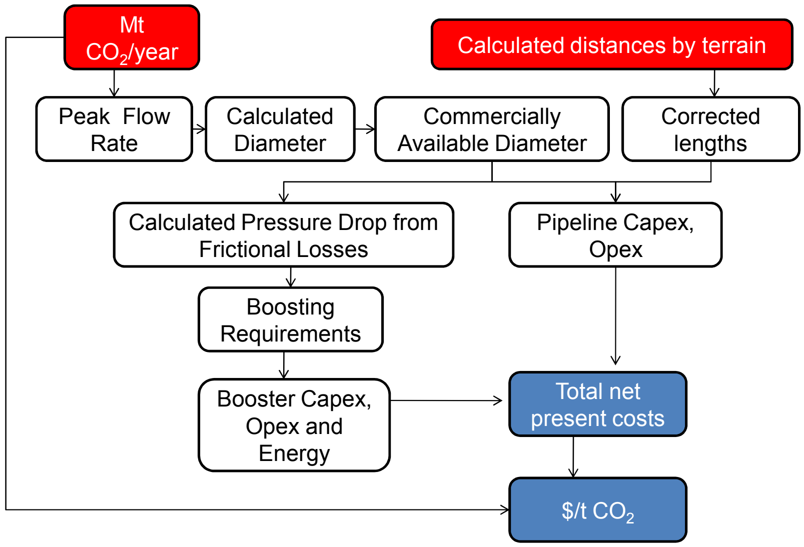


Figure 8 Pipeline sizing and cost model used (details are provided in Appendix 2).

Key inputs are capacity (Mt CO_2/year), the lengths (in km) of pipeline segments in different terrains, assumptions for maximum and minimum pressures (in kPa) allowed, velocity (in m/s), and pipeline roughness (in m). Capture, initial compression, drying, injection and other storage costs fall outside the scope of this study. Outputs are capex and opex terms for pipeline segments and boosters, and the energy required for boosters. The equations used in the cost modelling are listed in Appendix 2.

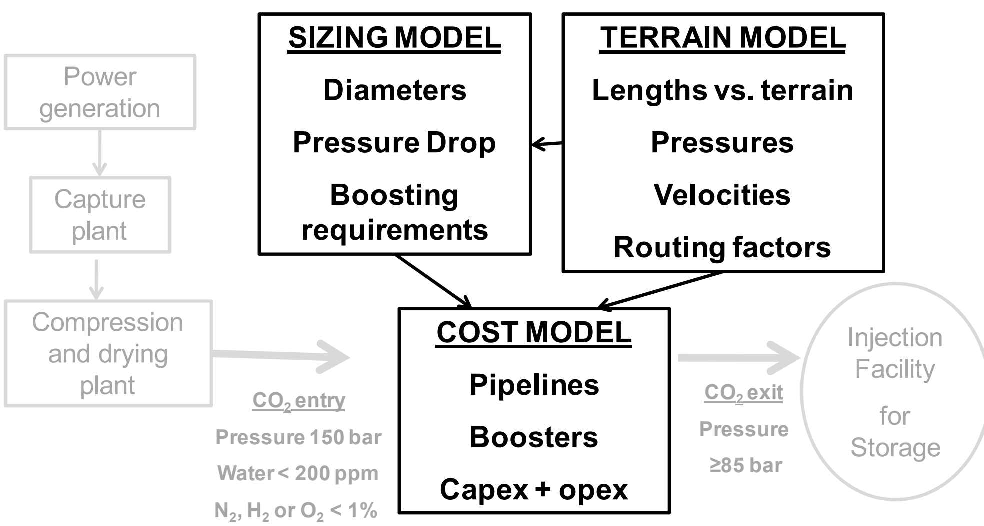


Figure 9: Sizing and cost model for CO_2 transmission pipeline model. Elements included within the cost model are shown in black. Elements outside of the cost model are shown in grey. Distribution networks from sink hubs to wells and storage are excluded from the model.

4.4 Source-Sink Matching

A simplified version of the GIS-spreadsheet algorithm for source-sink matching is described in the Figure below. The algorithm takes into account:

- Sink availability, based on the close of production date of gasfields, with an assumption that all aquifers modelled are available from 2030.
- The opportunity to link sinks to multiple sources, whilst ensuring the maximum capacity is not exceeded. Sources can only connect to the sink if the sink is capable of storing their captured emissions for a contracted period, which is 20 years in the baseline. Once a contract has been agreed, the capacity to store this volume of CO_2 is *committed*.
- Sources are weighted for selection by a sink based on a scoring system (see Section 4.4.1 below), which takes into account their proximity, the magnitude of their capturable CO_2 emissions, and the difficulty of intervening terrain.
- Once a source connects to a sink, it is not allowed to switch sinks at a later date.
- Where the same sources are selected by different sinks, the competition rules select the closest sink to the source to be connected.
- Where there is no competition for sinks, each sink connects to their favoured sources. Where there is a choice of which source connects to a given sink, the ten nearest sources are ranked so that larger and/or nearer sources are chosen, assuming the sink has sufficient capacity.

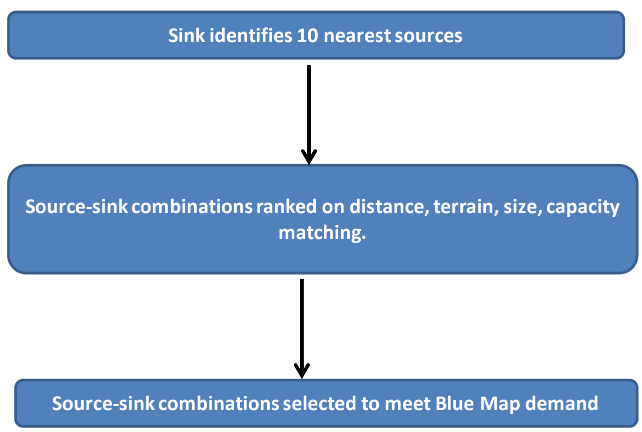


Figure 10: Source-sink matching

4.4.1 Description of scoring methodology

The ranking of sources based on proximity, emissions and terrain factors gives a ‘score’ for each combination. To determine which combinations are deployed in 2030 and 2050, a ‘score threshold’ was set which excludes combinations with scores above a critical value. Setting a low threshold excludes all but the most cost-effective pipelines, while setting a high score permits long pipelines crossing difficult terrain. The score threshold for each region was set in two ways. First, a threshold was set for each region at the minimum value required to deliver the Blue Map CCS demand for the relevant year. For some regions, such as the USA, this threshold was very low, since the entire demand can be met with relatively low cost pipelines. For others, it was not possible to meet the demand even with a high score threshold. In this case, a score threshold was set that maximised the region’s contribution to the Blue Map CCS target, while eliminating combinations which are inconsistent with historical pipeline routing. For the scenarios modelled, the maximum score threshold was found to be approximately 700 points. The sensitivity of the results to the choice of score threshold is described in the Results section.

4.5 Integrated infrastructure

In the 'baseline scenario', the model produces a set of 'point-to-point' networks. A variant is also explored that allows sources cluster to reduce pipeline requirements and costs. Whilst the study explored a range of geometries, it was decided to model clustering using tree and branch structures. The structure is shown in the following image:

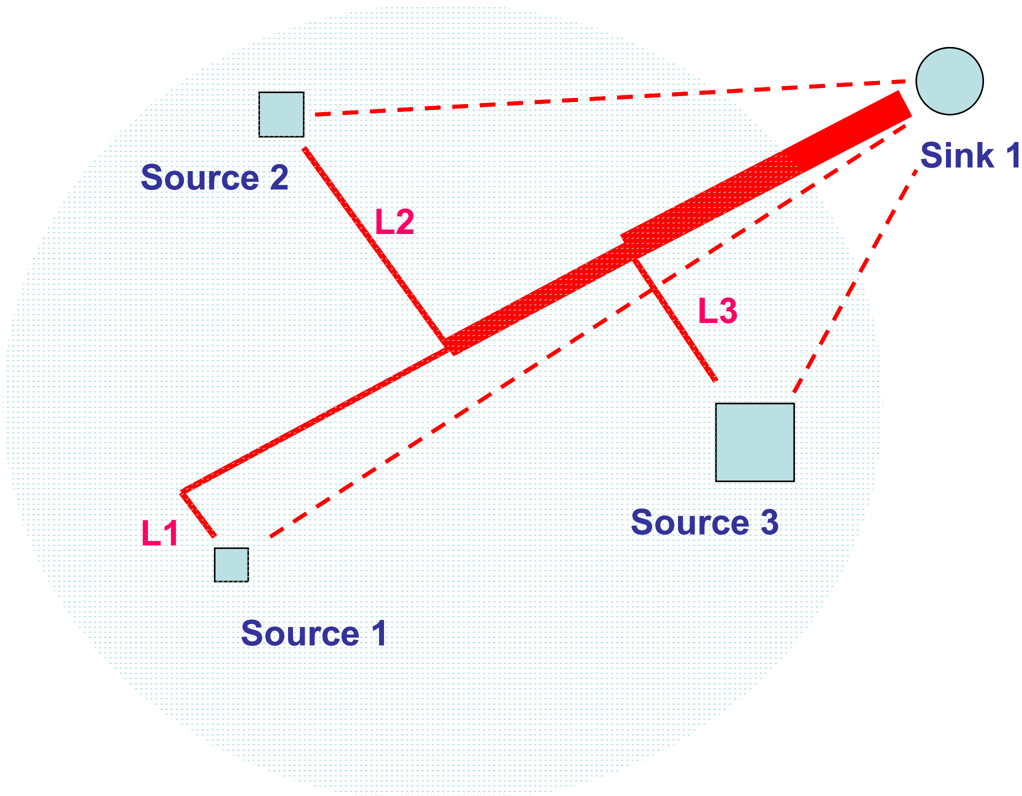


Figure 11 Schematic for integrated pipeline designs. Dotted lines represent the PTP networks replaced by a more efficient integrated network. Sources are "clustered" if the resulting tree and branch network is more efficient than the PTP network.

5 RESULTS OF CO_2 NETWORK MODELLING

5.1 Introduction

As described in the previous chapter, the network algorithm identifies and connects sources to sinks, prioritising and dispatching the least costly pairs, on a simple “point to point” basis, until the IEA Blue Map target is achieved. The Blue Map target is defined on a regional basis, and the model develops networks at two points in time, 2030 and 2050.

The model is run for baseline conditions and for a number of sensitivities. A key sensitivity is the level of aquifer availability (as shown below, this is a key constraint on the transport networks). A second dimension explores the development of integrated, clustered networks (rather than simple point-to-point) and the efficiencies and savings that may result.

In all cases a key issue that is examined is the regional variation in network topology, extent, cost and the ability to meet the Blue Map target.

5.2 Baseline networks

5.2.1 Baseline 2030

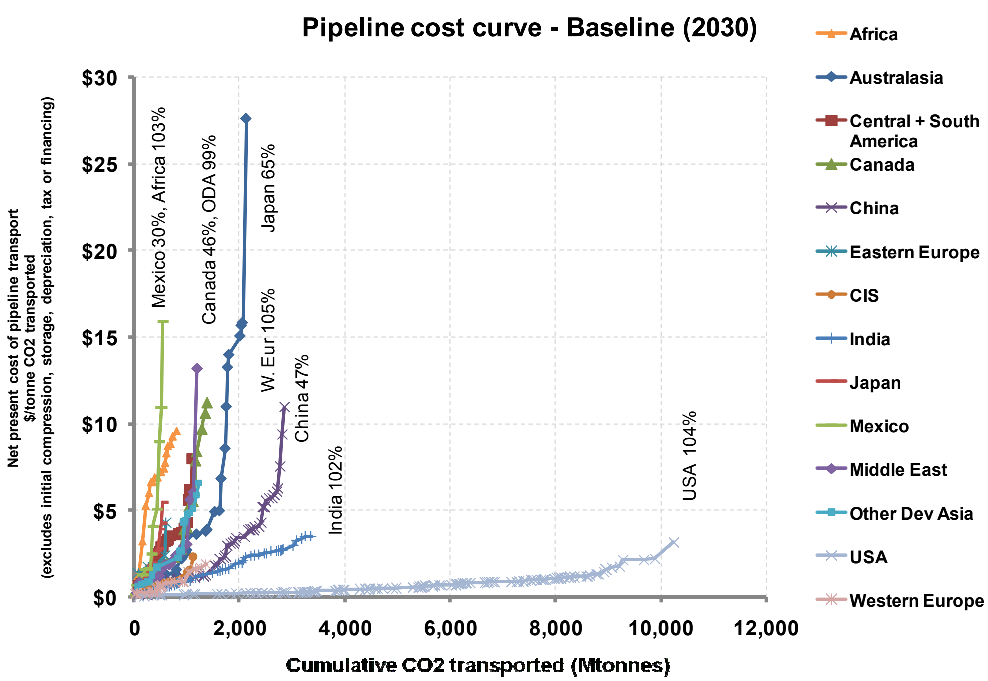


Figure 12 Regional marginal transport cost curves (transport) in 2030 and 2050. IEA Blue Map is the CO_2 target for each region.

The figure above shows the marginal abatement pipeline cost curves for the world in 2030, one for each region studied. Points of note are:

- USA networks are comprised of a large number of onshore, and relatively short, pipelines. These pipelines are therefore relatively inexpensive when compared to other regions.
- Not all regions are projected to meet their 2030 Blue Map target. Such shortfall regions include China which achieves circa 50% of the target with the baseline

assumptions on storage capacity. Clearly increasing the modelled storage capacity for any given region would elongate the corresponding curve along the x-axis.

- In attempting to meet the target, these regions use progressively more expensive source/sink combinations to the extent that the marginal cost becomes very high.
- While the network optimising algorithm ensures cheaper combinations are used first, it cannot prevent these expensive (and potentially unviable) networks being generated in order to approach the target.
- In shortfall regions, the unused sink capacity is very far from CO_2 sources and thus is not connected as networks would be expensive (on a $/t CO_2 basis).

5.2.2 Baseline 2050

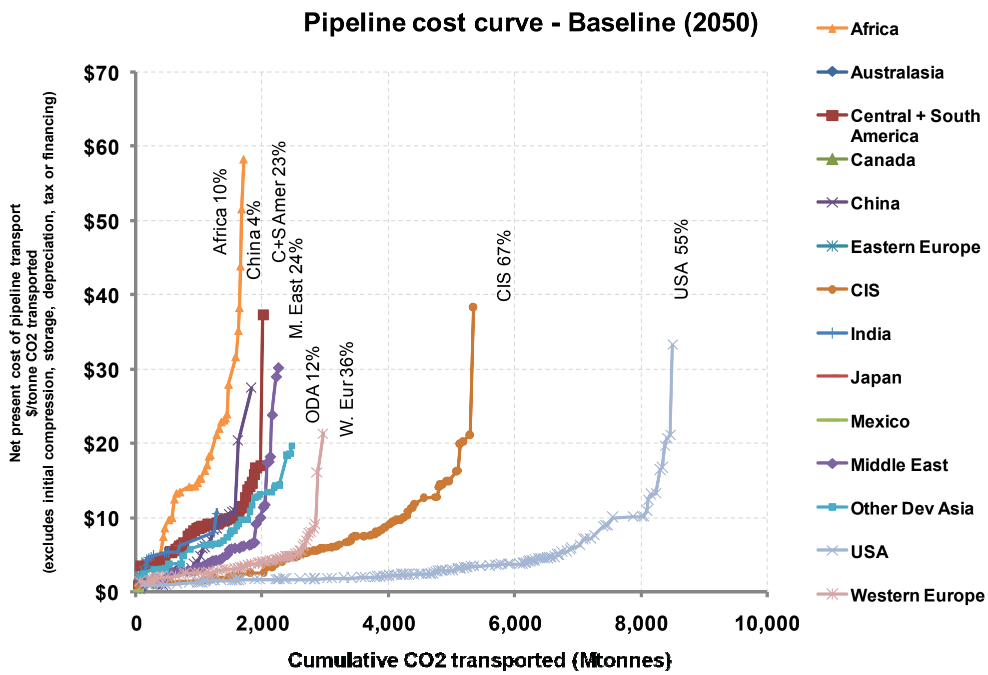


Figure 13 Regional marginal transport cost curves (transport only) in 2050 for the baseline scenario. IEA Blue Map (ETP 2008) is the CO_2 target for each region.

The figure above presents regional marginal transport cost curves for meeting the 2050 Blue Map target in 2050.

- In 2050 no region is projected to meet its target with the baseline assumptions on storage capacity.
- As a result, all regions exhibit a similar trend where marginal pipeline transport costs become very high.
- The USA and CIS perform relatively well; these regions are relatively well served with gas fields that are modelled as available by 2050.
- Worldwide however, aquifers are vital component of 2050 networks and their modelled capacity limits the total CO_2 stored. Clearly more generous assumptions on storage capacity for any given region would have the impact of elongating these curves along the x-axis. Conversely, restrictions on CCS would have the opposite effect.

GIS maps of modelled regional networks are provided in Section 5.5 below.

5.2.3 Baseline global marginal transport cost curve

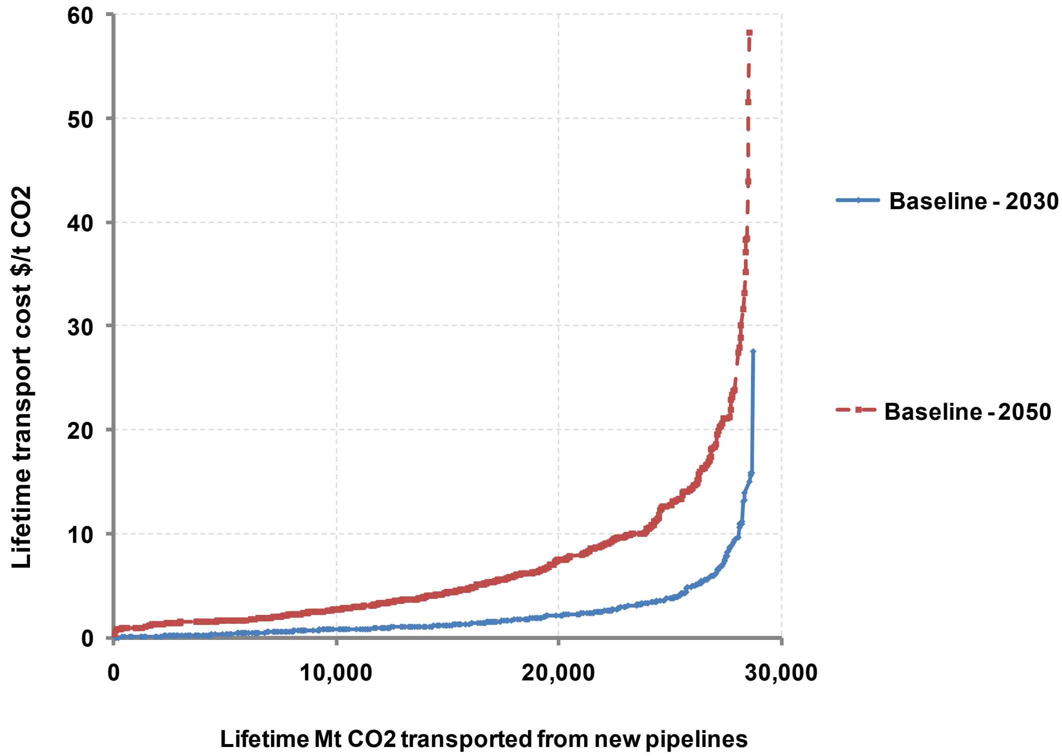


Figure 14 Global marginal cost curves (transport only) for new pipelines in 2030 and new pipelines in 2050.Each point on the curve corresponds to the CO_2 and cost for a single source connected to a single sink with baseline scenario assumptions. The points are ranked in order of cost.

The figure above shows the base case global cost curves for 2030 and 2050. The Blue Map target in 2030 is 1.8Gt per annum, and in 2050 is 10 Gt per annum.

- Globally new networks transport 1.4 Gt p.a. in 2030, of which 0.8 Gt pa is still operating in 2050.
- Globally new networks transport 1.4 Gt p.a. in 2050[19], when added to the contribution from 2030 networks that are able to continue beyond 2050, this results in an annual transported rate of 2.2 Gt p.a. in 2050.
- 2030 networks use up most of the 'easier' source-sink combinations (on the basis of proximity, terrain etc.). This is the reason why 2030 networks are less costly than 2050 networks.
- In 2050, new sink capacity (gas fields) becomes available. However only a fraction (circa 60%) is within a viable distance of sources and so remain unconnected. The resulting shortfall in relation to the 2050 target is significant.
- The sink capacity in the model is ca. 560Gt (lifetime), of which ca. 28+28+15Gt (12%) is matched using the baseline scenario assumptions. Matching greater volumes is possible, but transport costs would be even higher. Clearly more favourable assumptions on sources, sinks and demand have the potential to increase the matched capacity – this is discussed later.

[19] The near equivalence between the 2030 and 2050 lifetime CO_2 volumes of new connections (at circa 29Gt each for new networks) is coincidence – as shown below, other simulations do not show this correspondence.

5.2.4 Regional differences in storage in 2030 and 2050

It is important to begin discussion of regional analysis with the important caveat that in many cases low aquifer availability modelled may result from very poor exploration of capacity to date, rather than geological restrictions. This will strongly influence the modelling of source-sink matching and thus the marginal cost curves.

Figure 14 above shows that in the baseline scenario, very similar total quantities of CO_2 are stored in new networks in 2030 and 2050. Table 4 below shows the regional differences in CO_2 storage between 2030 and 2050. Although the global totals are similar, there is wide variation in storage within each region. For example, four times more CO_2 is stored in 2050 networks than in 2030 in the CIS, while three regions experience no additional CCS deployment in 2050 in the baseline.

The small change in the overall quantity of CO_2 stored in the two timeframes reflects the small change in the overall availability of sinks between 2030 and 2050. In 2030, the available sink capacity is 346 Gt (based on all sinks with close of production dates before 2030). In the baseline, 29 Gt are stored in these sink between 2030 and 2050, while an extra 16 Gt are stored in networks that operate for longer than 20 years. This means that the sink capacity available for new networks in 2050 is 302 Gt. In addition, a further 89 Gt of storage capacity is available from new sinks in 2050, although only 60% (53 Gt) of this can be connected without excessively high pipeline costs. Adding 53 Gt to the remaining capacity from previous sinks results in a total potential for new networks of 355 Gt in 2050, only 10 Gt higher than the capacity in 2030.

Table 4 Regional contributions to modelled global CO_2 transport in 2030 and 2050 (baseline scenario)

	Baseline Scenario		
	2030 (Mt p.a.)- new networks modelled	2050 (Mt p.a.) - new networks modelled	Difference (Mt p.a.)
Africa	41	85	44
Australasia	104	0	-104
Central + South America	55	100	45
China	143	93	-50
Eastern Europe	30	8	-22
CIS	56	267	211
India	168	65	-103
Japan	27	0	-27
Mexico	27	0	-27
Middle East	60	113	53
Other Dev Asia	61	123	62
South Korea	11	0	-11
USA	512	427	-86
Western Europe	69	148	79
WORLD	**1,433**	**1,431**	**-2**

At a global level, only 13% of the total modelled sink capacity is matched with sources in 2030 and 2050 in the baseline scenario. This figure shows large regional variation, with Eastern Europe, Japan, Mexico and South Korea, utilising over 70% of their respective modelled baseline sink capacities (see Table 5). However, the CIS and Middle East show very low sink utilisation of sinks over the model timeframe. This is because sinks in these regions are located close to one another, and large distances from the majority of sources. This means that if a particular sink is unable to connect to any sources in a cost effective manner, it is likely that the neighbouring sinks will also not connect, since they have similar pipeline costs to the sources.

It is worth noting that there is a limitation in the source/sink matching algorithm concerning the re-selection of sources, which may lead to some sinks being under-utilised in the model. The matching algorithm is based on each sink assessing the relative costs of connecting to the ten nearest sources. There may be cases that another sink has lower costs of connection to the same ten sources (due to lower pipeline distances or easier terrain). In this case, the first sink would 'lose' its ten nearest sources to the competing sink. The algorithm as implemented does not attempt to select and evaluate the next closest sources (for example the 11th to 20th) closest, and as a result, the sink in this example would remain unconnected.

For the majority of sinks, this limitation has only a small effect on the overall CO_2 stored, since sinks that fail to connect to one of their ten nearest sources are already large distances from sources and so are unlikely to connect to even more distant sources. However, for regions with extensive clustering of sinks, such as the Northern and Central North Sea, CIS and the Middle East, the algorithm may underestimate the total sink utilisation.

Table 5 Total committed Mt CO_2 storage in 2030 and 2050 as a percentage of modelled total sink capacity in the baseline point-to-point scenario.

	Total sink capacity modelled in baseline scenario	Total committed storage (2030-2050 and 2050-2070)	% of total sink capacity committed in baseline scenario
Africa	16,833	3,147	19%
Australasia	26,158	2,901	11%
Central + South America	28,625	3,916	14%
China	10,157	5,427	53%
E Europe	924	864	94%
CIS	160,730	7,565	5%
India	11,374	5,536	49%
Japan	842	718	85%
Mexico	806	618	77%
Middle East	139,617	4,286	3%
Other Dev Asia	19,478	4,831	25%
South Korea	388	343	88%
USA	80,559	25,400	32%
W Europe	63,032	5,052	8%
World	**563,510**	**72,732**	**13%**

5.2.5 Sensitivity to choice of scoring threshold

As described in the modelling methodology, the deployment of CCS networks in the model is determined by the target and by setting a critical score threshold for each region in 2030 and 2050. The score threshold is an indication of the marginal cost of the most costly point-to-point pipeline in a region. The table below shows the score thresholds used in 2030 and 2050 for the baseline and no aquifers scenario. In 2030, many regions, such as the US and

Western Europe, have sufficient sink capacity to meet the Blue Map CCS demand using relatively low cost networks. Other regions, such as China and Eastern Europe, fail to meet the 2030 target even with a high score threshold of 700. In the baseline scenario in 2050, none of the regions meet the IEA Blue Map (ETP2008) demand for that year even when the score threshold is raised to 700 for most regions. A maximum score threshold of 700 was chosen as this value eliminated extremely high cost pipelines that wouldn't be considered feasible in real life. For Western Europe, a lower threshold is required to prevent the deployment of impractical point-to-point pipelines, such as pipes which cross the fjords of Norway.

	2030		2050	
	baseline	no aq.	baseline	no aq.
Africa	120	120	700	700
Australasia	650	700	650	700
Central + South America	180	200	700	700
Canada	650	650	700	650
China	700	700	700	700
Eastern Europe	700	700	700	700
CIS	49	49	700	700
India	140	700	700	700
Japan	700	700	600	700
Mexico	700	700	700	700
Middle East	90	90	700	700
Other Dev Asia	305	335	700	700
South Korea	300	500	700	700
USA	14	700	500	700
Western Europe	13	19	200	200

The choice of maximum score threshold in the model is calibrated partly by reference to known oil and gas pipeline plans (for example available at http://www.theodora.com/pipelines/world_oil_gas_and_products_pipelines.html), and partly subjective judgement, the exact value chosen has a relatively small impact on the overall quantity of CO_2 stored. This is because once low cost networks are deployed, the marginal abatement curve steepens considerably, so that relatively large changes in transport costs cause small changes in the amount of CO_2 stored.

The table below shows the effect of changing the maximum score threshold on the amount of CO_2 stored in 2050 in new networks. Increasing the maximum threshold to 900 increases the amount of CO_2 stored from 1,430 to 1,488 Mt per year. This is equivalent to an extra 1.2 Gt over a 20 year period, an increase of 5% over the baseline. However, this change only increases the percentage of the Blue Map demand met in 2050 from 15.3% to 16%.

Score threshold	CO_2 stored in new networks in 2050 (Mt p.a)	% of 2050 Blue Map demand met
900	1,488	16.0%
800	1,460	15.7%
700	**1,430**	**15.3%**
650	1,403	15.0%
500	1,360	14.6%
300	1,200	12.9%

5.3 Global Sensitivities

5.3.1 Aquifer availability

The baseline results above indicate that limited sink capacity – and the poor disposition of these sinks in relation to sources - is constraining the model from achieving the required target, particularly longer term. In the baseline the available aquifer storage capacity is modelled as 2% of the published capacity. This is a reasonable starting assumption for a worldwide generic study and is in line with previous studies. As mentioned, it was not possible within the scope of the study to produce an exhaustive standardised dataset of sink capacities given the diversity of methods used to calculate storage capacity. Therefore the impact of aquifer storage capacity assumptions was explored through sensitivity analysis. The importance of aquifers in meeting Blue Map targets has informed two sensitivities, which examine networks with no aquifer availability, and with high aquifer availability. A strength of the model is that it can potentially be rerun as datasets are refined.

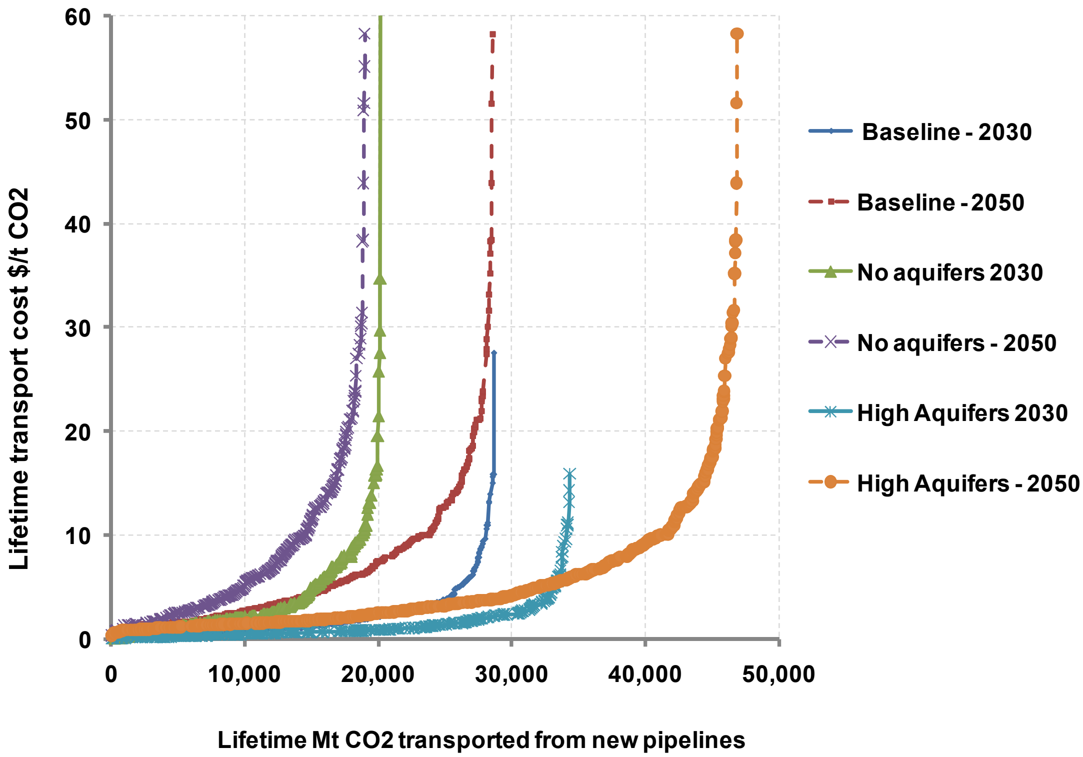


Figure 15 2030 and 2050 marginal transport cost curves for new point-to-point pipelines in 2030 and new pipelines in 2050, under baseline, no aquifer, and high aquifer scenarios. Each point represents a unique project.

- Without aquifers (i.e. giant gasfields only), the global matched capacity drops from the baseline by approximately 30%.
- Under the "high aquifers" scenario in 2050, matched capacity is almost double that of the baseline.
- With high aquifers, the 2030 matched capacity is 95% of the global target, but in 2050 the matched capacity only increases to 26% of the global Blue Map CCS demand, an increase from 15% in the baseline.

5.3.2 Global target in CO_2

Given the regional variation in the cost of networks identified above, we examined the potential efficiencies arising from a global approach to meeting a single blue map target in 2030 and 2050, rather than a regional approach, as in the baseline.

This does result in a cost saving relative to the baseline, although the difference is small. In the baseline, regions are already stretched to meet the Blue Map target (particularly in 2050) to the extent that there is no spare cheap capacity remaining in any one region, which could be used to offset a shortfall in another region.

5.4 Point to point versus integrated networks

While the point to point (PTP) networks used in the baseline are dispatched in the most cost effective manner, they do not make any attempt to cluster and thereby achieve transport cost efficiencies. A clustering algorithm, described in the prior chapter, examines groups of PTP pipelines, and clusters them together in a branch and trunk topology should there be sufficient pipeline length savings from doing so. Note that if clustering is not calculated to achieve savings, then PTP networks remain i.e. in the integrated networks there will be a combination of PTP pipelines and clusters where appropriate.

Table 6 Regional variation in use of clusters and efficiencies that result.

Region	Total Point to Point Pipeline Length (km)	% of CO_2 in clusters (Central scenario)	Length saving in central scenario (km)	% change in length within the clusters	% length saving overall
Africa	21,214	77%	7,579	46%	36%
Australasia	0	0%	0	0%	0%
Central + South America	17,267	59%	4,359	43%	25%
China	7,063	50%	2,452	69%	35%
CIS	25,809	80%	6,988	34%	27%
Eastern Europe	386	39%	33	22%	9%
India	3,737	31%	851	74%	23%
Japan	0	0%	0	0%	0%
Mexico	0	0%	0	0%	0%
Middle East	8,913	62%	3,072	55%	34%
Other Dev Asia	13,702	58%	3,166	40%	23%
South Korea	0	0%	0	0%	0%
USA	22,227	49%	4,235	39%	19%
Western Europe	9,767	61%	2,629	44%	27%
World	**130,085**	**59%**	**35,364**	**46%**	**27%**

The table above summarises the regional results of the clustering algorithm. It shows the percentage of CO_2 transported in clustered pipelines. As can be seen, there is wide variation in the use of clustering between regions. In some regions, no clustering is observed, while in others a very high percentage of CO_2 transported is in clusters.

Within clusters, a pipeline length saving is achieved. Again there is wide regional variation in the percentage saved within a cluster, but 33%-50% saving is relatively frequent, with commensurate savings in cost[20]. Variation between regions is caused by differences in distances between sources and sinks, and the degree of geographical clustering of sinks. For example, benefits of clustered networks are maximised where sources are located close to one another (which reduces the length of the branches used to connect to the trunk pipeline) and the distance to the sink is high (which maximises the benefit of a single large trunk pipe relative to multiple low capacity pipelines).

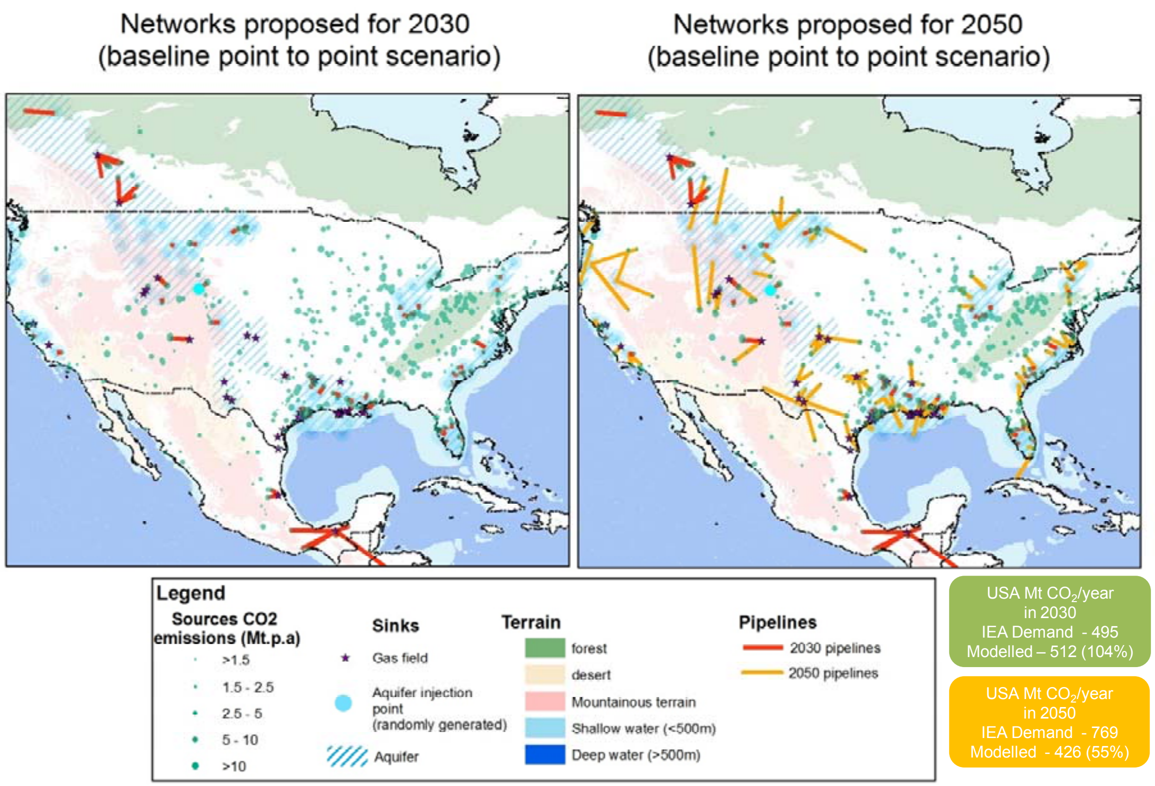
The clustering algorithm achieves the same CO_2 volumes as the PTP as it uses the same sources/sinks. Given the length/efficiency savings observed in some areas, clustering could be combined with allowing longer pipelines (effectively, longer trunk lines) to connect more (or different) sources and sinks, but this has not been examined in this study. Other studies (carried out mostly for regions in Europe and the US) have examined the costs and benefits in more detail

5.5 Selected region maps (2030 and 2050)

Clearly the inevitable limitations of applying generic global models and datasets to study regions is only suitable for very high level analysis – and does not substitute for more detailed studies that benefit from greater local knowledge. In the pages below we present a number of regional maps which illustrate aspects of network topologies and location. Associated CO_2 throughput (Mt CO_2/year), and comparison to Blue Map (ETP 2008) targets, are provided.

[20] Reductions in cost are more pronounced for more marginal sources – especially if at low utilisation rates.

5.5.1 USA and North America



Baseline point-to-point modelled networks for USA.

The USA has the most cost-effective transport opportunities identified in this study.

The modelled pipelines meet USA IEA Blue Map CCS demand in 2030.

2030 pipelines are relatively short, without significant challenges from offshore or mountainous terrains.

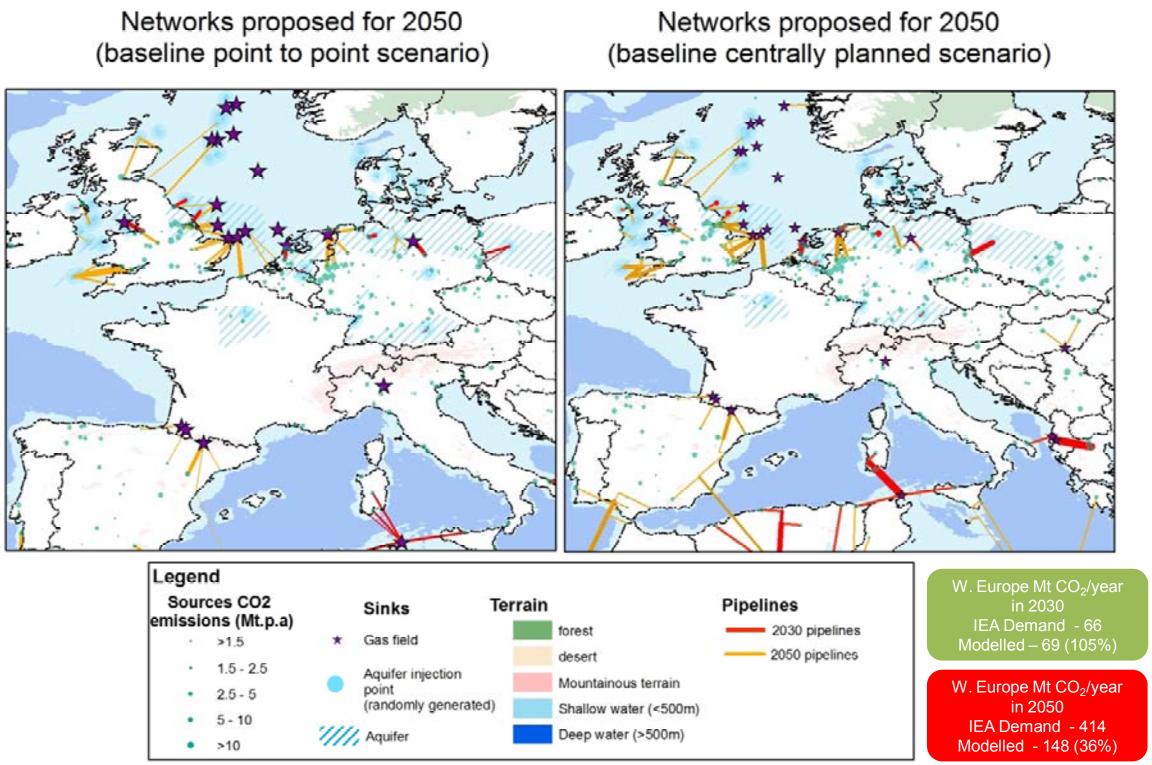
New networks in 2050 achieve 55% of IEA Blue Map CCS demand, although there is an additional contribution from 2030 networks that are still operating at that time.

To meet CCS demand in 2050, pipelines are typically longer and there is a greater use of pipelines crossing more challenging terrains, e.g. closer to mountains or offshore.

CCS in the USA is dependent on aquifers from 2050 but less reliant in the period 2030-2050 where giant gasfields provide an alternative storage opportunity.

In 2050, 49% of CO_2 is transported in clusters. The case for clustering in 2050 is less compelling.

5.5.2 Western Europe



Baseline point-to-point modelled networks for Europe.

Western Europe has moderately cost-effective transport opportunities identified in this study, in 2030 and 2050 under the baseline scenario.

The modelled pipelines meet Western European IEA Blue Map CCS demand in 2030 in the baseline scenario.

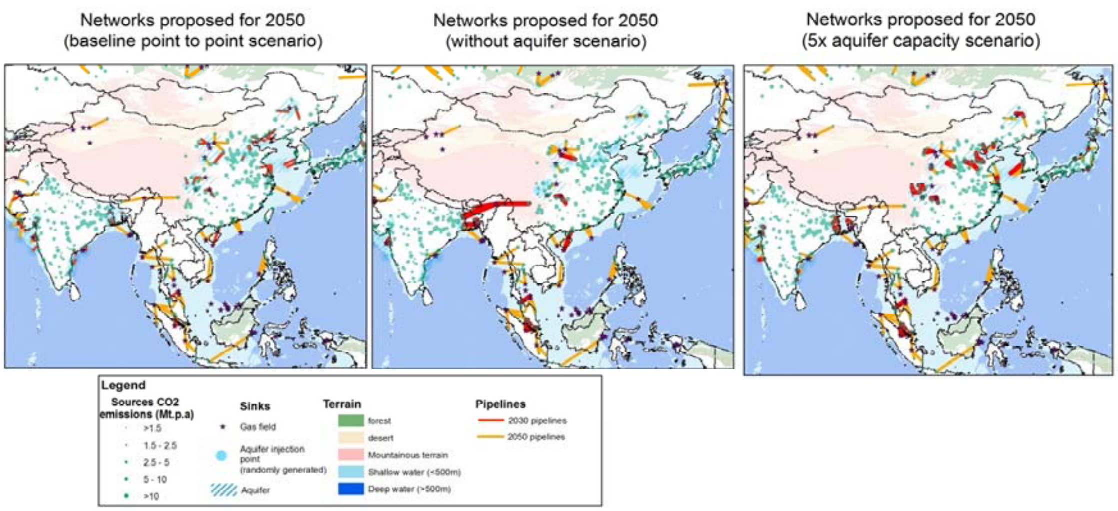
Pipelines for 2030 involve predominantly short pipelines – these are a mix of onshore and offshore.

New networks in 2050 achieve 36% of IEA Blue Map CCS demand in 2050 in the baseline scenario, although there is an additional contribution from 2030 networks that are still operating.

To meet Western Europe's CCS demand in 2050, pipelines are longer – with the North Sea playing an important role.

Source clustering leads to some savings, particularly in 2050 where a larger number of distant and offshore sinks are required.

5.5.3 Asia



India Mt CO_2/year in **2030**
IEA Demand - 165
Baseline Modelled – 168 (102%)

India Mt CO_2/year in **2030**
IEA Demand - 165
No Aquifers Modelled – 89 (54%)

India Mt CO_2/year in **2030**
IEA Demand - 165
High Aquifers Modelled – 176 (106%)

India Mt CO_2/year in **2050**
IEA Demand - 1153
Baseline Modelled - 109 (9%)
(of which 65 Mt CO_2/year from new pipelines)

India Mt CO_2/year in **2050**
IEA Demand - 1153
No Aquifers Modelled - 88 (8%)
(of which 24 Mt CO_2/year from new pipelines)

India Mt CO_2/year in **2050**
IEA Demand - 1153
High Aquifers Modelled - 370 (32%)
(of which 284 Mt CO_2/year from new networks

Points of note for Asia:

Within Asia, five regions are allocated by the IEA Blue Map with separate CCS demands. These are India, China, Japan, South Korea and "Other Developing Asia".

Under the baseline scenario, India, South Korea, and Other Developing Asia meet the IEA Blue Map CCS demand for 2030.

For 2050, source-sink combinations are less favourable, i.e. distances are longer, and there is a greater role for offshore sinks.

Asian sources are critically dependent on saline aquifer availability in 2030. Without aquifers (i.e. modelled as relying fully on giant gasfields), these regions struggle to meet even half of IEA Blue Map demand for either 2030 or 2050. Note that India's and China's giant gasfields typically have late Close of Production dates, modelled as available for 2050 but not necessarily 2030.

With aquifers, the capacity and cost-effectiveness of pipelines can be substantially improved.

There are benefits from integrated networks using clusters, particularly in 2030 and 2050. This is illustrated by way of a comparison of the marginal costs of centrally planned networks in India.

5.5.3.1 Sensitivity to aquifer availability in India and China

Storage in India and China has been explored at a very low level so uncertainties are extremely high. It is possible to model pipelines connecting CO_2 sources with sinks in India that meet the Blue Map 2030 requirement for 165 Mt CO_2 transported per year at \$4 /t CO_2 using point-to-point pipelines in the baseline scenario. Without aquifers (i.e. using giant gasfields only), the matching of sinks with sources is noticeably poorer. The model predicts that around half as much CO_2 is transported per year, with average and marginal costs considerably higher. In contrast, under the high aquifer scenario, the modelling predicts average and marginal costs of CO_2 transport well below \$1/t CO2.

By 2050, the model predicts that India would struggle to meet more than 9% of IEA Blue Map 2050 demand of 1153 Mt CO2/year under the baseline scenario. This is even more limited and more expensive under no aquifer scenario. Under a high aquifer scenario the model predicts India can achieve 32% of Blue Map demand.

China is highly dependent on the availability of aquifers in 2030, with 70% of CO_2 storage in aquifers and only 30% in gasfields. Many of China's gasfields are not available for CO_2 storage in 2030. In the 'no aquifers' scenario, CO_2 storage in 2030 drops by 70%, suggesting that there is no 'spare' gasfield capacity available at low cost to compensate for the loss of aquifers.

In 2050, additional giant gasfield sinks are modelled as available in China. In the baseline scenario, *ca.* 100% of CO_2 stored in new networks in 2050 occurs in gasfields. Removing aquifers therefore does not noticeably reduce the CO_2 stored from new networks in 2050. Interestingly, the model predicts a small increase in the CO_2 transported in 2050. The total CO_2 stored in the model between 2030 and 2070 decreases from 270Mt in the baseline from 5.4Gt in the baseline to 4.3Gt without aquifers. The increase in CO_2 stored after 2050 reflects the deferral of connections relative to the baseline, since sources must now 'wait' until gasfields become available rather than connecting to aquifers in 2030.

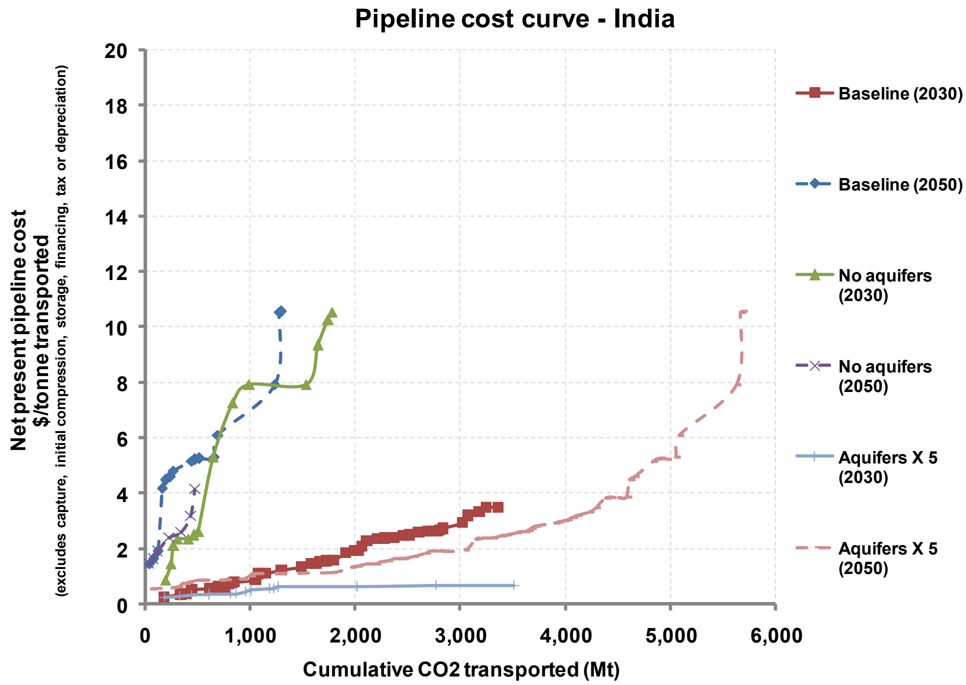


Figure 16 Pipeline cost curve for India

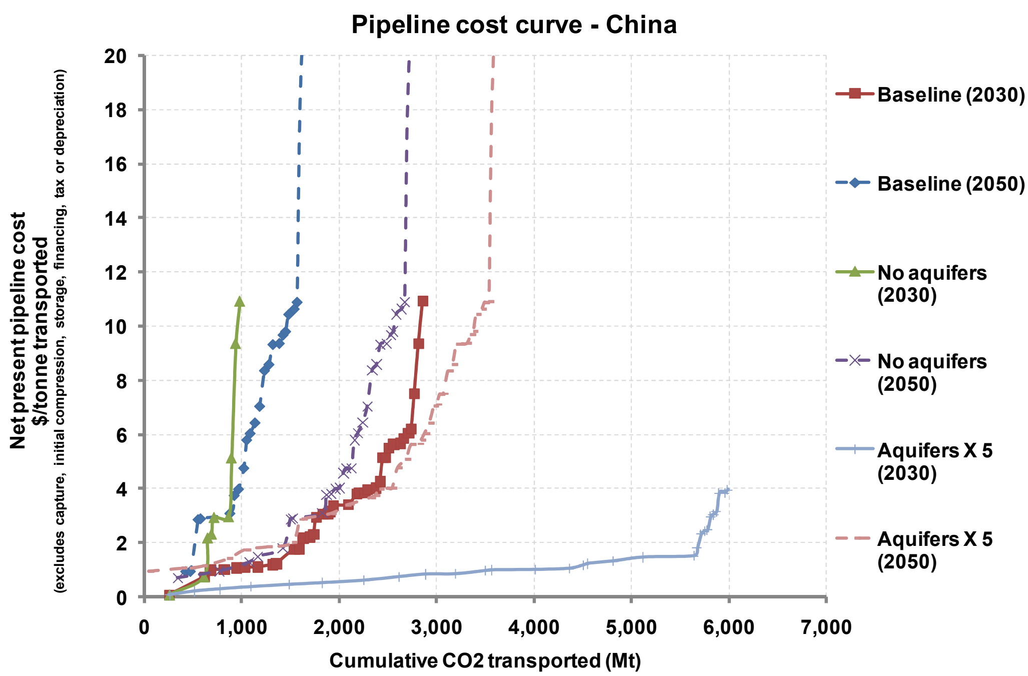


Figure 17 Pipeline cost curve for China

5.5.4 Conclusions and Recommendations

The network modelling carried out in this study suggests that over 1.4 Gt of CO_2 per year can be stored in giant gasfields and aquifers in 2030. This increases to 2.2Gt of CO_2 in 2050, of which 1.4 Gt are in new networks. However, the total CO_2 captured in 2050 is equivalent to only 15.5% of the IEA Blue Map CCS demand in that year. Other conclusions from the study are:

- There is large regional variation in the ability to meet the Blue Map CCS demand. Western Europe and the USA can meet the 2030 target using relatively low cost networks, while China, Japan, Mexico, and South Korea are unable to meet the target with their modelled sink capacity.
- Several regions, including China and India are heavily dependent on saline aquifers for CO_2 storage. The USA is almost entirely dependent on aquifer storage in 2050, having committed the most of its cost-effective gasfield sinks in 2030.
- Increasing the availability of aquifers (from 2% of their published capacities to 10%) increases the proportion of the Blue Map demand met in 2050 from 15.5% to 23%. Although the uncertainty in absolute sink capacity is very important, this suggests that it is the geographic distribution of sources and sinks, rather than actual sink capacity, which is most limiting opportunities for cost-effective CO_2 transport.
- In the model baseline, only 13% of total sink capacity is matched with sources in 2030 and 2050. The majority of the unmatched capacity is in the CIS and Middle East, where sinks tend to be clustered close to one another, and far from suitable sources.
- Connection of sources and sinks through integrated networks, rather than through point to point pipelines, can reduce total pipeline lengths by 25% for a given amount of CO_2 storage, with a corresponding pipeline cost saving. Due to differences in the distribution and clustering of sources, the benefit of integrated networks varies between regions.

This study makes the following recommendations:

- The IEA Blue Map targets should be re-evaluated to better reflect the ability of different world regions to meet them given the uncertainties over capture timing, transport network growth feasibility, and sink availability[21]. The 2050 target appears very challenging for any region to meet with the baseline storage assumptions modelled in this study and should be revisited with greater input from reservoir engineers.
- Extensive mapping of aquifers, and greater standardisation of methods, should be carried out to better characterise total capacities and the potential for CO_2 storage, especially in regions where storage opportunities in giant gasfields are limited.
- The proximity of suitable sinks should be a consideration for the siting of new large stationary sources, in order to maximise opportunities for CCS. Opportunities for this may be limited for many places in the developed world, since new sources tend to be built on existing sites due to planning restrictions. For many sources, such as power plants, the benefits of locating close to suitable sinks must be balanced with the need to connect to end users e.g. through the electricity grid,and also the need to source fuel at a reasonable cost).
- Clustering of sources and the creation of integrated CO_2 networks should be encouraged where possible to minimise overall transport costs. Further work should be conducted at regional and local scales to better quantify the benefits of integrating networks for individual sources (e.g. in terms of reducing risks and transaction costs vs. the higher up-front costs).

[21] Since the production of this report, the IEA has updated its ETP2008 analysis with its Roadmap analysis, available at www.iea.org

6 LEGAL AND REGULATORY ISSUES FOR THE TRANSPORT OF CO_2.

6.1 Legal impediments to cross-border CO_2 transport.

A principal consideration is how 'captured CO_2' is to be classified in national or regional legislation (e.g. if it is classed as a waste with some hazardous properties), which will subsequently determine which international treaties might apply [Raine, 2009]. Even if CO_2 itself is not considered hazardous, legal restrictions will apply if:

- impurities in the CO_2 stream are considered hazardous by their presence, or are present in significantly high levels in terms of total mass flow [22], or
- supercritical CO_2 is considered a dangerous or explosive substance, with the potential to damage its surroundings [Raine, 2008].

At an international level, the *Basel Convention,* the *Basel Ban Amendment* and the *Bamako Convention* (in Africa) control the trans-boundary movement of waste[23]. Article 6 of the London Protocol may also preclude the storage in geological media below the seabed CO_2 if the CO_2 has been shipped across frontiers for that purpose. The treatment of CO_2 has not yet been formally determined in these conventions, or in the case of the London Protocol, where trans-boundary movement is involved. If CO_2 is considered as a hazardous waste, then the Basel and Bamako Conventions would impose requirements for waste transfer notifications and prior approvals to be gained, or in the case of movement from OECD to non-OECD country, a full prohibition on the movement. The most serious impact of these conventions could be to reduce the opportunities for CO_2 pipelines that connect sources in one country with sinks in another country.

6.1.1 Basel Convention

The Basel Ban Amendment bans the export from OECD to non-OECD countries of hazardous wastes intended for final disposal. This poses two considerations: firstly, whether captured CO_2 would be considered hazardous under the terms of Basel Convention; and second, whether storage of CO_2 in geological formations is considered "disposal".

Classification of captured CO_2 as a hazardous waste would have multiple impacts, including[24]:

[22] The mass flow of impurities may need to be below a threshold value to avoid triggering these concerns.
[23] These treaties are supplemented with multilateral or bilateral treaties.
[24] A. Raine, Transboundary transportation of CO_2 associated with carbon capture and storage projects: an analysis of issues under international law, available at http://www.ccsassociation.org/docs/2008/Transboundary%20CO2%20Raine.pdf .

Potential Barriers	Impact
Requirement not to permit exports and imports of CO_2 to and from non-parties;	Moderate
Requirement only to export the CO_2 if the state of export does not have the necessary disposal capacity itself	Moderate
Potential non-consent from transit states who have the right to prohibit transit passage – this could be a significant – could lead to excessive detours or transit fees.	High
Prohibition on exports to parties where the exporting party has reason to believe that the CO_2 will not be managed in an environmentally sound manner. Absence of clear internationally agreed regulations on storage site selection and management.	High
Obligation to cooperate with parties to improve and achieve environmentally sound management of the stored CO_2 Absence of clear internationally agreed regulations on storage site selection and management.	High
Documentation, notification and consent requirements will increase costs and delays to multinational CCS projects[25].	Moderate
Importing states and transit states which are parties may require the CO_2 to be covered by insurance or other guarantee	Low

Impurity levels in CO_2 could, however, significantly alter the interpretation of the Basel Convention requirements. Certain impurities may present a strict prohibition (e.g. certain metals such as mercury, cadmium or other metals) whilst others could pose a restriction through the characteristics exhibited under mass flow i.e. through the presence of a certain level in the pipeline inventory/mass flow which triggers certain hazardous properties. An example of the latter could include hydrogen sulphide, which is acutely toxic to humans and the environment in levels above 50 ppm in air, and/or toxic at lower levels under chronic exposure conditions.

Notwithstanding this analysis, the IEA [26]concluded that Article 1 and accompanying Annex I (list of hazardous wastes) would not easily apply to captured CO_2, whilst Article 1 in reference to Annex III (hazardous classification) would appear to certainly not apply to captured CO_2 as it does not exhibit a hazard characteristic described thereunder.

In terms of storage, it is likely that CCS activities constitute disposal under the Basel Convention. Annex IV of the Convention includes disposal covering *Deep injection*, (e.g., injection of pumpable discards into wells, salt domes of naturally occurring repositories, etc.) and *Permanent storage* (e.g., emplacement of containers in a mine, etc.)

The most obvious way to remove the impediments posed by the Basel Convention would be to introduce a specific amendment for captured CO_2 in a similar way as applied by the EU and under other international treaties (such as for the 1972 London Convention and 1996 Protocol thereto, where the activity itself is now allowed albeit with a need to clarify trans-boundary movement, and the 1992 Convention for the Protection of the Marine Environment of the North East Atlantic; OSPAR) as described below. However, to date, there does not appear to have been any serious debate on the issue of CCS within the Basel Convention Conference of Parties.

[25] See: Zakkour 2007: Task 2: "Choices for Regulating CO_2 capture and Storage in the EU". ECN/Norton Rose/GIG/ERM. Discussion paper for the European Commission, DG Environment.
[26] IEA (2007) "Legal Aspects of Storing CO2: Update and Recommendations". IEA, Paris.

6.1.2 Bamako Convention

The Bamako Convention prohibits trade in waste into Africa and controls it within Africa. The scope of this convention is similar to but more restrictive than the Basel Convention. There is a greater restriction on which countries can exchange waste (i.e. only countries within Africa would be permitted to exchange CO_2) and because of a wider interpretation of hazardous waste than under the Basel Convention (Raine, 2009). Presently, the issue of CCS has not been debated within the framework of the Bamako Convention. The Bamako Convention has largely been superseded by the introduction of the Basel Ban Amendment.

6.1.3 UNCLOS

UNCLOS establishes a comprehensive legal regime to govern activities in and around the world's seas and oceans. Article 195 of UCLOS instructs states not to transfer hazards from one area to another or transform one type of pollution into another. Whether supercritical or dense phase CO_2 is a hazard is currently open to interpretation. It is presently considered that UNCLOS does not impose any prohibitions on the transport of CO_2 by pipeline.

6.1.4 London Convention and the 1996 London Protocol

The London Convention, which applies to all marine waters other than internal waters, requires that Contracting Parties are guided by a precautionary approach to environmental protection of marine environment. In 2006, Contracting Parties to the London Protocol, adopted amendments to the 1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972. Overwhelmingly pure CO_2 streams from CO_2 capture processes for sequestration can now be stored if the disposal is into a sub-seabed geological formation, and no wastes or other matter are added. The Contracting Parties have also developed guidelines in the form of Risk Assessment Framework (FRAM) procedures to complement regulation of sub-seabed geological sequestration.

These amendments regulate the sequestration of CO_2 streams from CO_2 capture processes, and thus refer primarily to storage rather than transportation. The London Convention legal and technical working group has identified that the Article 6 of the London Protocol prohibits the export of CO_2 streams from the jurisdiction of one contracting party to any other country, whether that party is a contracting party or not. The Government of Norway has drafted a proposed amendment, which has yet to be debated by the contracting Parties[27].

6.1.5 OSPAR Convention

An amendment to the OSPAR Convention now permits the storage of overwhelmingly pure CO_2 provided that disposal is into a sub-soil geological formation, and are intended to be retained permanently and will not lead to significant adverse consequences. There is now a requirement to follow OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 streams in Geological Formations. The OSPAR Convention was also amended to allow all routes for storage of CO_2, i.e. allowing the reuse of existing pipeline infrastructure.

It is worth noting, however, that at the time of writing the amendment to the OSPAR Convention has not entered force, having only been ratified by Norway, and thus requiring six other contracting Parties to ratify.

[27] The proposed amendment is due to be debated on 31st Consultative Meeting of the Contracting Parties & 4th Meeting of Parties to the Protocol, 26-30 October 2009. Available here: http://www.imo.org/includes/blastDataOnly.asp/data_id%3D25444/5-1.pdf

Classification of supercritical or dense phase CO_2 as a hazard, waste or explosive may prohibit or complicate its transfer across borders. As an example, the Basel Convention imposes strict controls systems on the transfer of hazardous waste between countries, allows transit countries to prohibit transit passage, and force compliance with as-yet-undefined environmental standards on storage. The Basel Ban Amendment, although not yet in force, is morally binding for signatory Parties and imposes a complete restriction on the transfer of hazardous waste between mainly OECD and non-OECD countries. Similar provisions occur in the Bamako Convention – developed prior to the Basil Ban Amendment to protect African nations from importing hazardous waste. The London Convention, and more specifically the 1996 Protocol thereto, has been interpreted as preventing the trans-boundary movement of CO_2 for safe storage in geological media under the seabed (Article 6). Consequently, Norway has proposed an amendment to the Protocol which is currently working its way through the London Convention amendment process, and is due first reading late in 2009. The OSPAR Convention has also been amended to allow for storage of CO_2 in sub-seabed geological media in the North East Atlantic area, subject to the risk assessment frameworks set down in the amendment. However, OSPAR still presents a barrier to CO_2 storage operations as this amendment will only enter into force once seven Parties have ratified; to date only Norway has.

Given the characteristics and scope for impurities within captured and compressed supercritical and dense phase CO_2, there is a risk that opinions will differ about the classification of CO_2 streams. If deemed as hazardous within the scope of the Basel Convention and Ban Amendment, the additional restrictions and burdens placed on CCS project developers may delay implementation where cross-border shipments are involved. The EU's CCS Directive provides a useful legal precedent for de-classifying CO_2 captured for the purpose of geological storage from waste management legislation. It is recommended that, subject to appropriate safeguards, the potential for similar exemptions for CO_2 for CCS is investigated for the Basel, Bamako and London Conventions.

6.1.6 Accounting Conventions for UNFCCC and National Greenhouse Gas Inventories

Emission reduction accounting practices ultimately define where the value of avoided CO_2 emissions is located – be it for national governments under UNFCCC or Kyoto Protocol type obligations, or for private operators acting in response to emissions trading or other incentive mechanisms. For the most simple of CCS networks, involving one source and one sink, both located in the same country, CO_2 accounting practices are unlikely to have any significant impact on CO_2 transportation infrastructure.

However accounting conventions may become difficult to unravel for more complex projects. Such projects may involving multiple sources and/or sinks, components that are 'oversized' or which connect at different times, and projects span multiple jurisdictions. In some cases, emission reduction accounting guidelines may deter optimised network architecture in favour of projects that fit with the accounting rules. Examples include:

- Currently absent accounting mechanisms for CCS within the United Nations Framework Convention on Climate Change and Inventory Guidelines thereunder.
- Economic incentives for CCS, such as cap-and-trade schemes[28] or project-based incentives such as the Clean Development Mechanism[29], where narrow definitions for scheme boundaries may lead to suboptimal structures for CCS networks.

[28] Zakkour et al., Inclusion of CCS within the EU ETS, on behalf of ERM.
[29] Zakkour et al., Inclusion of CCS within the CDM, on behalf of IEA GHG.

For the former, application of the 2006 IPCC National Greenhouse Gas Inventory Guidelines will result in the assignment of liability of any emissions from the pipeline to the country in which the emission takes place, as these will be added to the countries national emissions inventory. The consequences of this will only occur where the country has a legally binding emission limitation or reduction obligation under any Protocols to the Convention. It is worth noting that the 2006 IPCC guidelines propose a default emission factor approach to estimating pipeline leaks, implying that some emissions will always be allocated to a country's emissions if no pipeline leak takes place. In most instances, the liability will ultimately pass down to operators through legislation, for example, as in the EU by way of including CO_2 pipelines in the Emissions Trading Scheme.

In the case of the latter, the EU has recently proposed draft guidelines on the treatment of emissions accounting for CCS[30], which impose monitoring obligations on operators, and liability to purchase allowances (emission rights) equal to any emission recorded. The proposed draft guidelines do not provide guidance on how any emissions from pipelines might be allocated in National Greenhouse Gas Inventories in cases where the pipeline crosses national boundaries, and the precise location of the fugitive release is uncertain. Issues around multiple sources are not relevant as the entity operating the pipeline is liable for any emissions; it is likely that such liability would be made joint and several through private contracts/transfer agreements drawn up between exporters and shippers.

The UN Framework Convention on Climate Change requires all Parties to develop, periodically update, publish and make available to the Conference of Parties (COP), national inventories of greenhouse gases emissions. The national inventory is a record of all anthropogenic sources of emissions and removals by sinks for a given period (a year for Annex I Parties) within the Party's territory. They must be compiled using comparable methodologies reflecting best available scientific knowledge, and are regularly reviewed to take account of this requirement. The inventory reporting framework provides the basis for compliance with the Convention, as well as quantified emission limitations imposed on ratifying Annex I Parties to the Kyoto Protocol to the Convention.

To date, three sets of national greenhouse gas inventory guidelines have been produced by the Intergovernmental Panel on Climate Change (IPCC):

- The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (1996 GLs)
- The IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000 GPGs)
- The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 GLs)

Presently only the 1996 GLs and the 2000 GPGs are approved for use by the Conference of Parties[31] (the COP) for use in preparing Party's national inventories. Approval of the 2006 Guidelines by the COP is presently under debate at the time of writing. Neither the 1996 GLs nor the 2000 GPGs contain any specific information on accounting for emissions/emission reductions from CCS activities, despite operational CCS projects taking place in various parts of the world. Thus, the 2006 GLs include specific guidance on inventory compilation that includes CCS. In the context of cross-border CCS projects, and subsequent allocation of any emissions into national greenhouse gas inventories, the 2006 GLs propose that:

- CO_2 may be captured in one country, Country A, and exported for storage in a different country, Country B. Under this scenario, Country A should report the amount of CO_2 captured, any emissions from transport and/or temporary storage that

[30] Available at: http://ec.europa.eu/transparency/regcomitology/searchform/DocumentDetail.cfm?dDx/kmU+kFpfdLRJ+5Pj3sdH+pMq8q3ib18+cRQrLnrj83kKhIhMeIoQkhazA52W

[31] The supreme body of the Convention

takes place, and the amount of CO_2 exported to Country B. Country B should report the amount of CO_2 imported, any emissions from transport and/or temporary storage, (that takes place in Country B), and any emissions from injection and geological storage sites."

- "If CO_2 is injected in one country, Country A, and travels from the storage site and leaks in a different country, Country B, Country A is responsible for reporting the emissions from the geological storage site. If such leakage is anticipated based on site characterization and modelling, Country A should make an arrangement with Country B to ensure that appropriate standards for long-term storage and monitoring and/or estimation of emissions are applied (relevant regulatory bodies may have existing arrangements to address cross-border issues with regard to groundwater protection and/or oil and gas recovery)."

- "If more than one country utilizes a common storage site, the country where the geological storage takes place is responsible for reporting emissions from that site. If the emissions occur outside of that country, they are still responsible for reporting those emissions as described above. In the case where a storage site occurs in more than one country, the countries concerned should make an arrangement whereby each reports an agreed fraction of the total emissions."

In terms of emissions from pipelines and allocation to inventories, no guidance is provided. Whilst this issue may need to be resolved in future, it is unlikely to present an issue for trans-boundary pipeline movements.

In conclusion, the UN Framework Convention on Climate Change and Kyoto Protocol thereunder do not impose any prohibitions on CCS or trans-boundary movement of captured CO_2. Rather, the Kyoto Protocol explicitly requires signatory Parties to research, promote, develop and increase use of carbon dioxide sequestration technologies (Article 2).

To address these deficiencies, the study recommends

- That supporters of CCS networks encourage further consideration among the Conference of Parties (COP) on the benefits of adoption of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, which include specific guidance on inventory compilation that includes cross-border CCS projects.
- Guidelines are issued on how financial incentive schemes should deal with CCS networks.

6.1.7 EU CCS Directive

The EU's CCS directive was adopted by the Council early in 2009 and clarifies the regulatory framework governing CCS development and operation within Europe. The Directive applies to the geological storage of CO_2 within the territory of the Member States, in their exclusive economic zones and continental shelves. The Directive applies only to projects that store a cumulative amount of CO_2 greater 100 kt. In the context of transportation of CO_2, the CCS Directive includes considerations over CO_2 purity standards, third party access to infrastructure; for which further details are outlined below.

As a contracting Party to the London Convention, the European Union has reflected its commitments thereunder by imposing constraints on the composition of the CO_2 stream. Furthermore, it also bound by the terms of the OSPAR Convention, as further reflected by the need to evaluate the risk by applying the Risk Assessment Framework incorporated in its amendments.

Thus, Article 12 of the CCS Directive stipulates that...:

> "the CO_2 stream shall consist overwhelmingly of carbon dioxide. To this end, no waste or other matter may be added for the purpose of disposing of that waste or other matter. However, a CO_2 stream may contain incidental associated substances from the source, capture or injection process and trace substances added to assist in monitoring and verifying CO_2 migration. Concentrations of all incidental and added substances shall be below levels that would: (a) adversely affect the integrity of the storage site or the relevant transport infrastructure; (b) pose a significant risk to the environment or human health; or (c) breach the requirements of applicable Community legislation."

Access to CO_2 transport networks and storage sites, irrespective of the geographical location of potential users within the Union, could become a condition for entry into or competitive operation within the internal electricity and heat market, depending on the relative prices of carbon and CCS. It is therefore necessary to make arrangements for potential users to obtain such access, accomplished in a manner to be determined by each Member State, and applying the objectives of fair, open and non-discriminatory access. This shall take into account, *inter alia,* the transport and storage capacity which is available or can reasonably be made available as well as the proportion of its CO_2 reduction obligations pursuant to international legal instruments and to Community legislation intended to be met through CCS. Pipelines for CO_2 transport should, where possible, be designed so as to facilitate access of CO_2 streams meeting reasonable minimum composition thresholds. Member States should also establish dispute settlement mechanisms to enable expeditious settlement of disputes regarding access to transport networks and storage sites. Article 2 compels

> "Member States to take the necessary measures to ensure that potential users are able to obtain access to transport networks and to storage sites for the purposes of geological storage of the produced and captured CO_2. The access shall be provided in a transparent and non-discriminatory manner determined by the Member State. The Member State shall apply the objectives of fair and open access, taking into account: (a) the storage capacity which is or can reasonably be made available, and the transport capacity which is or can reasonably be made available; (b) the proportion of its CO_2 reduction obligations pursuant to international legal instruments and to Community legislation that it intends to meet through capture and geological storage of CO_2; (c) the need to refuse access where there is an incompatibility of technical specifications which cannot be reasonably overcome; (d) the need to respect the duly substantiated reasonable needs of the owner or operator of the storage site or of the transport network and the interests of all other users of the storage or the network or relevant processing or handling facilities who may be affected. Transport network operators and operators of storage sites may refuse access on the grounds of lack of capacity. Duly substantiated reasons shall be given for any refusal. Member States shall take the measures necessary to ensure that the operator refusing access on the grounds of lack of capacity or a lack of connection makes any necessary enhancements as far as it is economic to do so or when a potential customer is willing to pay for them, provided this would not negatively impact on the environmental security of transport and geological storage of CO_2."

Article 22 ensures that Member States shall have dispute settlement arrangements to enable disputes relating to access to transport networks. In the event of cross-border disputes, the dispute settlement arrangements of the Member State having jurisdiction over the transport network or the storage site to which access has been refused shall be applied. If more than one Member State covers the transport network, the Member States should ensure the CCS Directive is applied consistently. Article 24 ensures that, in cases of trans-boundary CO_2 transport, trans-boundary storage sites, the competent authorities of the Member States concerned meet jointly the requirements of the CCS Directive.

The Directive further requires that questions on the need for further regulation on environmental risks related to CO_2 transport are explored by 2015.

The CCS Directive also includes several amendments to existing EU law, either to add new provisions, include CCS within its scope, or remove certain potential impediments to CCS. Some of these hold implications for CO_2 transport. These include:

- *The Environmental Impact Assessment Directive* (85/337/EC): to include CO2 pipelines within its scope under Annex I and Annex II, meaning that pipelines of greater than 800 mm diameter and over 40 km length, including booster stations, must be subject to an EIA (as implemented in Member States legislation), as well as any major modifications to installations or where Member States consider relevant (via Annex II). The same applies to capture installations and geological storage sites;
- *The Large Combustion Plant Directive* (2001/80/EC): a new Article 9a to include a requirement for developers of new 300 MW_e power stations to assess *inter alia* whether transport facilities are technically and economically feasible. If CCS is technically and economically possible the plant should be made capture ready. This poses a requirement for at least preliminary assessments to be made of the feasibility of transport infrastructure development to be assessed, and presumably does not impose constraints on such assessments where cross-border transfers may be required as the most technically and economically feasible option. How this might work in practice has yet to be put to the test.
- *The Environmental Liability Directive (2004/35/EC)*: storage sites only.
- *The Integrated Pollution Prevention and Control Directive (2008/1/EC)*: capture plant only

6.2 Regulatory challenges in allowing for the permitting of CO_2 pipelines in given jurisdictions

The study recognises that land use planning regulations will be the greatest impediment to rapid development of pipeline networks. Principally, this relates to establishing new pipeline corridors and gaining rights of way access for new pipelines in OECD countries. When CO_2 pipelines can be laid alongside existing natural gas pipeline corridors, some of these impediments may be partially eased. A range of factors will influence the timing of decisions, including:

- Regional and national approaches to planning of major infrastructure projects. This in turn may be influenced by factors such as population density and land tenure laws.
- Political will (both nationally and locally) to develop such projects;
- The presence of certain sensitive zones within the planned corridor e.g. major conurbations, nature reserves, military zones and national monuments;
- Public perception and perceived risk and benefits of such development;
- Technical information, e.g. the lack of empirical data on CO_2 release and dispersion characteristics could impede risk assessment, disclosure of risk, and subsequently pipeline permitting in all jurisdictions.[32]

By way of illustration, the UK government White Paper entitled "Planning For A Sustainable Future" concluded that whilst the current planning system has proved effective in delivering sensible judgements, problems include:

- The length of time required to deliver decisions, imposing significant costs and generating large amounts of uncertainty. This also has knock effects (e.g. for the economy and environment) and can deter promoters from brining on projects in the first instance.
- The length of time makes it difficult for civil society to engage in the process.

[32] Thanks go to Angus Evers of SJ Berwin for his inputs on this component of the study.

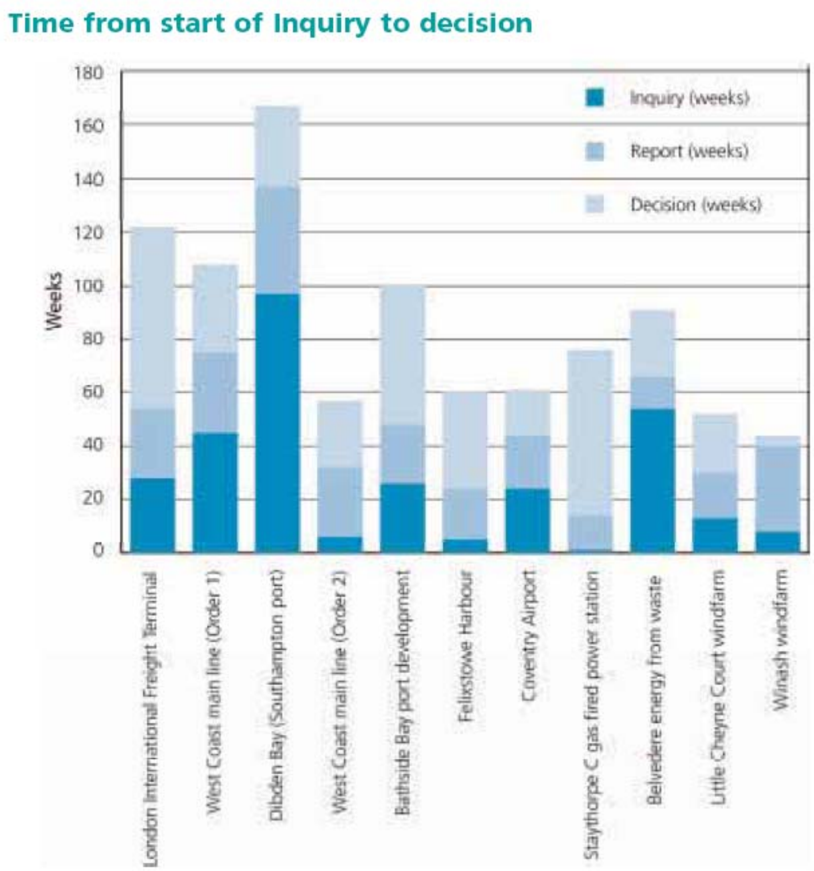


Figure 18 Length of time from planning enquiry to decision making in the UK. Source: HMSO (2007) "Planning for a Sustainable Future".

In addition, the UK Government 2007 White Paper entitled "Meeting the Energy Challenge" further highlighted the specific planning challenges posed by the UK planning system in meeting future energy infrastructure development requirements. It highlighted that it can take 3 years to secure a consent for an electricity infrastructure project where a public enquiry has been held. It also highlighted that in terms of gas infrastructure development, of the 4 applications made in 2006, three were rejected by local authorities.

The delay, cost, uncertainty and success rate will severely hamper the ability to rapidly deploy CCS infrastructure, in particular pipelines. On the other hand, where significant political will exists, then decisions can be far more easily reached. Political will, in turn, is affected by the clarity of Governments strategic policy directions. Given the UK's Climate Change Bill and attendant legal emission reduction commitments, mitigation of the effects of planning delays should bode well for future CCS infrastructure development. Furthermore, in some cases, political will can serve to ensure rapid development of a pipeline project. For example, the 316 km pipeline connecting the new South Hook and Dragon LNG terminals in Milford Haven to national gas grid in Gloucestershire took less than 5 years from starting the environmental impact assessment to project completion. In this case, the capacity for the grid operator (National Grid) to develop the pipeline under Permitted Development Rights resulted in rapid turnaround of planning consents. More impressively, the Teesside GasPort Project involving a 7 kilometre pipeline which passed under the river Tees and one of the most heavily industrialised areas of the country was approved and commissioned within 5 months (September 2006 and was commissioned in February 2007). The planning process, through two district councils, took only a few months to accomplish. Similar speed and the use of permitted development rights may be required to facilitate rapid deployment of CO_2 pipelines in the UK. Further, the new UK Planning Act is supposed to require decisions by the Infrastructure Planning Committee within 9 months, although the system has yet to be fully tested in practice. The characteristics of offshore pipelines mean that they are likely to be able to achieve all relevant permits in a more timely manner and at lower cost compared onshore pipelines[33]. For example, the significantly lower complexities around land owners (in the UK it is all the property of the Crown Estates), and the single permitting authority (in the UK, DECC) all make for a easier consenting process.

Planning delays are not confined to the UK. Figure 19 compares the time required for preliminary planning, gaining consents, contracting and construction for major transport projects in different countries in Europe (Pedler/TRL, 2003). The graph shows that, across Europe, the period for planning and gaining consent can exceed ten years. Since contracting and construction periods can also exceed ten years, the graph forcefully highlights the urgency with which infrastructure planning needs to begin in order for significant pipeline infrastructure to be in place by 2030.

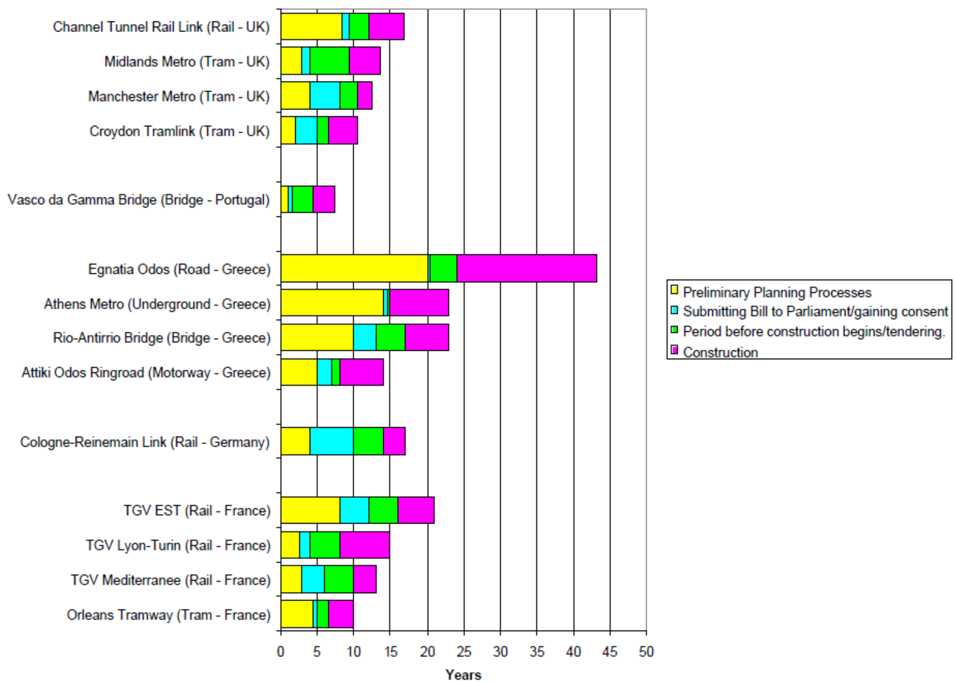


Figure 19 Length of the planning procedures of major transport projects by country. Original copyright Association for European Transport, 2003.

In conclusion, the timely construction and operation of CO_2 pipeline infrastructure is contingent on a successful planning and consenting process, which may involve meeting the requirements of diverse stakeholders. Even within a single country, major infrastructure processes may take many years to secure all necessary permits. Projects spanning multiple countries further require that permitting is coordinated – i.e. a project can only commence when all necessary permits are secured from responsible authorities in all countries. This could also include a need for transit agreements and tariffs to be secured, adding greater complexity to the overall process. CCS infrastructure developers may therefore choose routes and configurations that minimise delays, rather than those that maximise CO_2 abatement or minimise cost. The network analysis carried out in this study has attempted to include the effects of long infrastructure planning and permitting timescales within the analysis in order to highlight where such considerations may pose impediments to the timely deployment of pipeline infrastructure.

[33] This was a supporting factor in the choice of route for the West African Gas Pipeline.

6.3 Review of Regional Jurisdiction Issues

6.3.1 USA

The Congressional Research Service has examined jurisdictional issues in the regulation of CO_2 pipelines[34]. The Energy Independence and Security Act of 2007 (P.L. 110-140) contains measures to clarify the framework for issuance of CO_2 pipeline rights-of-way on public land. Other legislative measures, including S. 2191 and S. 2323, encourage the development of CO_2 transportation technology. The Carbon Dioxide Pipeline Study Act of 2007 (S. 2144) requires the Secretary of Energy to study the feasibility of constructing and operating a network of CO_2 pipelines for CCS. If these pipelines crossed state lines, it could raise important issues concerning regulatory jurisdiction over siting and pricing.

Jurisdiction over CO_2 pipeline safety resides with the Office of Pipeline Safety (a branch of the Department of Transportation), under 49 CFR 195 Transportation of Hazardous Liquids by Pipeline. As reported by Zakkour *et al*. (2006)35, CO_2 pipelines must consist of appropriate materials to handle content, loading, temperature, and pressure. The pipeline, supports, valves and fittings must withstand external loads including earthquakes, vibration, and thermal expansion and contraction. Monitoring and leak detection systems and processes must be installed. A manual of written procedures for normal operation, maintenance and abnormal operations must be prepared and reviewed every year.

Jurisdiction over hypothetical interstate CO_2 pipeline siting and rate decisions is not clear. Jurisdiction could fall to the Federal Energy Regulatory Commission (FERC) or to the Surface Transportation Board (STB), or neither.

FERC is an important regulator in energy projects that involve interstate and international transport of electricity, gas, and fuels. The Natural Gas Act of 1938 (NGA) vests in FERC the authority to issue “certificates of public convenience and necessity” for the construction and operation of interstate natural gas pipeline facilities. This closely reflects the UK permitted development rights for the national grid, described in Section 8.2 FERC is also charged with extensive regulatory authority over the siting of natural gas import and export facilities, as well as rates for transportation of natural gas and other elements of transportation service. FERC also has jurisdiction over regulation of oil pipelines pursuant to the Interstate Commerce Act (ICA). The ICA, as amended by the Hepburn Act of 1905, provided that the Interstate Commerce Commission (ICC) was to have jurisdiction over rates and certain other activities of interstate oil pipelines, as these pipelines were considered to be “common carriers.” This jurisdiction was transferred to FERC in the Department of Energy Organization Act of 1977. FERC’s jurisdiction over oil pipelines is not as extensive as its jurisdiction over natural gas pipelines. FERC is not involved in the oil pipeline siting process. However, as with natural gas, FERC does regulate transportation rates and capacity allocation for oil pipelines. The STB, an independent regulatory agency affiliated with the Dept. Of Transportation acts as a forum to resolve disputes on common carriers, including roads and some pipelines.

Approximately 5,800 kilometres (3,600 miles) of CO_2 pipeline operate today in the United States. The oldest long-distance CO_2 pipeline in the United States constructed for EOR is the 225 kilometre Canyon Reef Carriers Pipeline (in Texas), which began service in 1972. Other large CO_2 pipelines constructed since then, mostly in the Western United States, have expanded the CO_2 pipeline network for EOR. These pipelines carry CO_2 from naturally occurring underground reservoirs, natural gas processing facilities, ammonia manufacturing plants, and a large coal gasification project to regional oil fields. Federal regulation of siting and rates for these pipelines has not been addressed, due in large part to the fact that many of them are intrastate and that they often transport CO_2 for the benefit of the pipeline’s owners (so there are no rate or service disputes).

34 Vann and Parfomak, (2008) Regulation of CO_2 Sequestration Pipelines: Jurisdictional Issues (CRS Report for Congress)
35 Zakkour *et al*. (2006) Permitting Issues for CO_2 Capture and Geological Storage (IEA GHG 2006/3)

The Cortez CO_2 pipeline runs through Colorado, New Mexico and Texas. FERC disclaimed jurisdiction over this pipeline, emphasising that its role was to regulate natural gas specifically. Following a period of consultation, the Interstate Commerce Commission (ICC, now replaced by the STB) took a similar view. However the General Accounting Office (GAO) since took a contrasting view, and Federal Agencies are allowed to change their positions on the issue of regulatory jurisdiction.

If FERC and STB continue to disclaim jurisdiction over CO_2 pipelines, there could be a regulatory gap over interstate pipelines. This may not pose any immediate problems, as the The Office of Pipeline Safety within the Dept of Transportation would oversee safety (via PHMSA - Pipeline and Hazardous Materials Safety Administration), and any anti-competitive behaviour by the owners or operators of a CO_2 pipeline could be addressed by federal antitrust enforcement agencies, including the Federal Trade Commission and the antitrust division of the US Dept. of Justice.

At the State and local level, it is necessary to identify all the appropriate Agencies that have permitting authority, which can be quite time consuming – and there may be inconsistencies between Agencies. Zakkour *et al*. estimated that permitting new CO_2 pipelines would likely require between two and four years to achieve completion, although this could be reduced if existing rights of way for CO_2 EOR pipelines could be reused for CO_2 transported for sequestration.

ICF have carried out an extensive examination of regulatory issues around pipeline infrastructure for the USA, on behalf of the INGAA Foundation. A summary of the contrasting regulatory oversight for natural gas, oil and CO_2 pipelines is shown below:

Element	Oil Pipelines	Gas Pipelines	CO_2 Pipelines
Rates Regulation Authority (Interstate)	FERC	FERC	None (Possibly STB)
Regulatory Regime	Common Carriage	Common Carriage / Contract Carriage	Private, Contract, or Common Carriage
Ownership of Commodity	Mostly third-party ownership	Mandated that interstate pipelines only transports gas owned by others.	Common for CO_2 owned by pipeline owner / third-party
Tariffs / On-going regulatory oversight	Yes - rates are approved by FERC and increase indexed to PPI +/- an increment	Yes - Rates are periodically set by rate cases before FERC	No - STB would only look at rates if a dispute is brought before it.
Rate disputes	Every five years the increment to PPI is modified.	Rare for disputes outside of rate cases. However they can be brought before FERC	Uncommon due to ownership relationships and prearranged deals
Siting	State and local governments	FERC	State and local governments
Safety	PHMSA	PHMSA	PHMSA
Market Entry and Exit	Unregulated entry and exit	Need approval for both entry (construction) and exit (abandonment)	Unregulated entry and exit
Product Quality	"Batch" modes transport different products at different times. Not	Specifications individually set in tariff approved by FERC	No Federal Regulations*
Posting information	Tariff information is available on-line	Daily operational and tariff information is available on-line	None Required
Eminent Domain	Yes - Varies by state. More often if pipeline is a common carrier.	Yes	Varies by State Law

Figure 20 Regulatory framework for oil, gas and CO_2–EOR pipelines in the USA.(Copyright ICF International for the INGAA foundation). PPI – Producer Price Index.

Assuming the context of a national greenhouse gas reduction policy, the government is assumed to play a role in developing the legal and regulatory basis for a CO_2 transportation system that meets standards of public convenience and necessity. The ICF study concludes that the experience from CO_2 pipelines for EOR is not relevant, and that a new framework is required as (i) the siting of CO_2 pipelines for CCS may involve greater proximity to centres of population; (ii) may involve a mesh of interstate CO_2 transport, and (iii) unlike CO_2 for EOR, the CO_2 transported for sequestration will have no inherent positive value – instead transport economics will more closely approximate waste economics. These economics will be critically dependent on government-directed policies on CO_2 (which have yet to be specified).

On the basis of their analysis, ICF recommends that

- Responsibility for pipeline safety remains vested in PHMSA.
- The siting, environmental impacts, interconnections, abandonment, access, certification and ownership should be overseen by FERC.

- A federal authority (e.g. FERC) is given eminent domain status, to allow pipelines to be sited against local disapproval[36].

6.3.2 Australia

Zakkour et al. (2006) report that current pipeline Acts in Victoria and Western Australia do not presently cover CO_2 and would require amending, a precedent for which has emerged in the Gorgon Project. In Victoria, onshore pipeline approvals fall under the Pipelines Act 1967, the Pipelines Regulations 2000 and Gas Safety Act 1997. The developer requires:

1. A permit to own and use a pipeline
2. A license to construct and operate a pipeline
3. A construction and environmental safety case (approved by the Minerals and Petroleum Regulation Branch)
4. A safety case for operation and maintenance (approved by the Office of Gas Safety).
5. A consent to operate

Gas pipelines running at less than 1050 kPa are exempt from the Pipelines Act. Low pressure lines are covered by the Gas Industry Act 1994.

In Western Australia, the grant of a pipeline license can be made following approval that all safety, technical and environmental requirements have been met. In some terrains permission must also be obtained from the Department of Conservation and Land Management and the Australian Environmental Protection Authority.

State jurisdiction extends three nautical miles from land. The Commonwealth, States and Northern Territory seek to maintain common principles, rules and practices in offshore regulation. As an example, approvals under the Victorian Petroleum (Submerged Lands) Act 1982 and those under the Commonwealth Petroleum (Submerged Lands) act 1967 are identical.

6.3.3 Canada

Zakkour et al. (2006) have detailed pipeline jurisdiction issues in Canada. The Federal Canadian National Energy Board Act (NEBA), Part III regulates the construction and operation of pipelines that connect Provinces or extend beyond the limits of any Province. The National Energy Board promotes safety, environmental protection, economic efficiency and security. Certificates from the National Energy Board are required to construct and operate a pipeline, and NEB is proposing to amend the Onshore Pipeline Regulation to encompass CO_2 transportation, which is currently not included.

Individual Provinces have jurisdiction over pipelines within States. As an example, the Alberta Pipeline Act and Pipeline Regulation require a licence to construct and operate a pipeline in the Alberta Province. Construction must follow Canadian Standards Association material and design standards. CSA Standard Z662 covers the design, construction, operation and maintenance of CO_2 pipelines for EOR. The Alberta Energy Resources Conservation Board control the issue of pipeline licenses, and the Board may make requests on land purchase, decommissioning plans, operating manuals, emergency plans, and design factors. The British Columbia Pipeline Act and Regulation stipulates that The British Columbia Oil and Gas Commission must issue certificates before a pipeline is constructed. There are specific regulations on the transport of sour gas (i.e. H_2S-containing). Saskatchewan also requires that operators obtain a license to construct, alter, operate or abandon a pipeline.

[36] It would appear that FERC is not keen to regulate CO2 transport and thus regulations remain within the jurisdiction of States. (R. Hattenbach, Bluesource, Personal Communication)

Encouragingly, a current medium-scale programme in the Weyburn oilfield receives CO_2 from a coal gasification plant in North Dakota for storage in oilfields, indicating that major CO_2 pipeline permitting, even across an international border can be solved by regulators.

6.3.4 UK

There has been a significant change in the consenting process in the UK since the previous IEA GHG Permitting Study in 2006. As described previously, the new Planning Act 2008 creates a new faster system for obtaining development consents, via a new Infrastructure Planning Commission, for certain nationally significant infrastructure projects in accordance with new National Policy Statements prepared and issued by the Government. Nationally significant infrastructure projects include —

- the construction or extension of a generating station;
- the installation of an electric line above ground;
- development relating to underground gas storage facilities;
- the construction or alteration of an LNG facility;
- the construction or alteration of a gas reception facility;
- the construction of a pipe-line by a gas transporter;
- the construction of a pipe-line other than by a gas transporter;
- highway-related development;
- the construction or alteration of harbour facilities;
- the construction or alteration of a railway;
- the construction or alteration of a rail freight interchange;
- development relating to the transfer of water resources;
- the construction or alteration of a waste water treatment plant;
- the construction or alteration of a hazardous waste facility.

Furthermore the Energy and Climate Change Acts embed CO_2 reduction and provide an outline framework under which CCS can be considered.

This new consenting system is at an early stage of its development. The IPC has significant requirements for pre application consultation and land negotiation (e.g. for wayleaves and leases if other pipelines are crossed) which will need to be complied with before any application can be submitted. Any development consent granted by the IPC can include other consents or permissions which are ancillary to the pipeline development. These could include the grant of planning permission for ancillary development, the authorising of compulsory purchase powers (where not already held through the provisions of a generating licence), and consents required where a pipeline is to run offshore such as consent under section 5 of the *Food and Environment Protection Act 1985* (for depositing articles in the sea or tidal waters) or section 34 of the *Coast Protection Act 1949* (which restricts works detrimental to navigation rights).

The development consent process through the IPC does however only apply to pipelines running within England and Wales. That part of the pipeline which runs offshore will therefore still require authorisation under section 14 of the The Petroleum Act 1998.

Additional requirements include:

- Meeting *Pipeline safety regulations, 1996* and *Pressure systems safety regulations 2000*
- Harbour Works Consent
- Hazardous Substances Consent
- Environmental Permit
- An environmental impact assessment under the The Pipeline Works (Environmental Impact Assessment) Regulations 2000; and
- An appropriate assessment may need to be made by the consenting authority under the Habitats Regulations 1994.

The Marine Management Organisation has yet to be established but will focus on the offshore environment. Under the Marine and Coastal Access Bill published in December 2008, the MMO will have a duty to exercise its functions in a consistent and co-ordinated manner with the objective of making a contribution to the achievement of sustainable development.

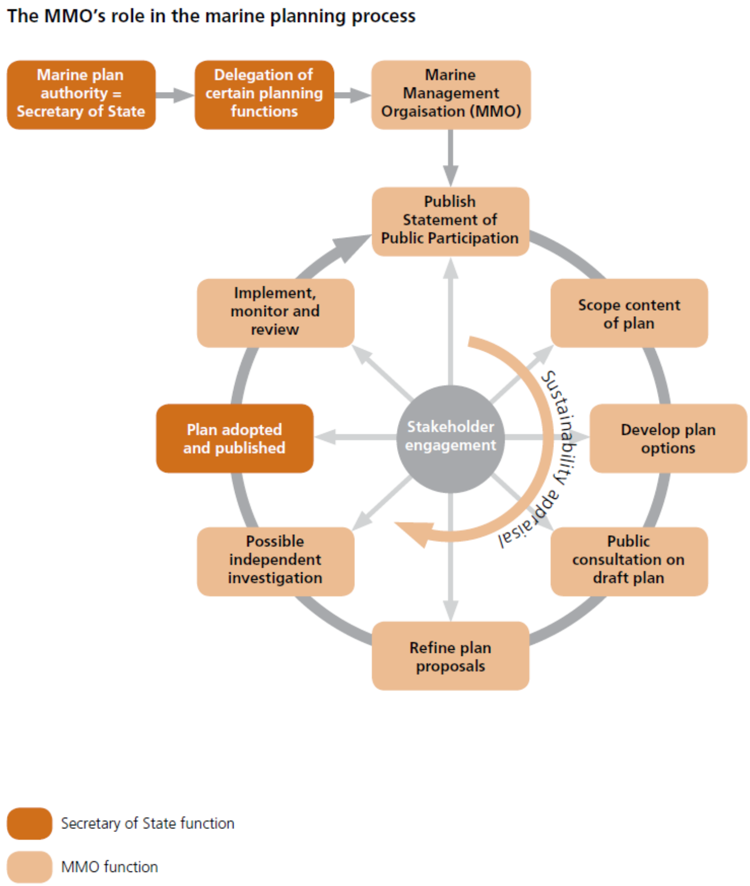


Figure 21 Role of the MMO (Marine maritime organisation) in planning.

The licensing and licensing enforcement provisions in the Marine and Coastal Access Bill (Part 4) combine existing regulatory regimes from the Food and Environment Protection Act 1985, the Coast Protection Act 1949, and Telecommunications Act 1984 (Schedule 2 Electronic Communications Code). Secondary legislation under this Part will further consolidate powers by incorporating the Marine Works (Environmental Impact Assessment) Regulations 2007, and the Marine Minerals Permissions under the Environmental Impact Assessment and Natural Habitats (Extraction of Minerals by Marine Dredging) (England and Northern Ireland) Regulations 2007. The MMO will regulate these activities as the licensing authority for the new regime. It will control the environmental, navigational, human health and other impacts of constructions, deposits and removals in the marine area. Examples of activities the licensing regime will cover are port developments; tidal and wave power projects; jetties; moorings; coastal dredging; aggregate extraction; and the laying of submarine cables.

In conclusion, inappropriate or uncertain regulatory jurisdiction provides a potentially significant hurdle, particularly for private investors. Areas where regulatory oversight may be important in some countries include safety, siting, pricing, third party access, and eventual decommissioning. Clear rules and boundaries for regulatory oversight are well developed for natural gas pipeline transportation. Although a dedicated regulator may not always be required, the current environment for how CO_2 pipelines for CCS will be regulated needs greater clarification.

The countries where CO_2 pipeline infrastructure developments will be significant in the short term have been identified from the network modelling. This study recommends that the jurisdiction of regulators for potential CO_2 pipelines is clarified in these regions, so that CCS project developers and their investors are given sufficient confidence over likely business environments.

6.4 Conclusions on legal and regulatory issues around international CO_2 pipeline transport.

The study has identified a number of important legal, financial and regulatory barriers to international CO_2 pipeline infrastructure, including

- Classification of CO_2 as a hazard may prohibit or complicate its transfer across national borders, for example both the Basel and Bamako Conventions prohibit this.
- Article 6 of the London Protocol to the London Convention prohibits the export of wastes from one country for dumping in the waters belonging to another country.
- Unclear national jurisdiction over CO_2 pipeline siting and regulation, for example in the USA.
- Pipeline routes may need to avoid particular areas, for example, military zones, sites of special scientific interest, and sites of cultural, historical or other special interests.

The study has also identified areas where significant progress has been made in reducing barriers to CCS. These include:

- The EU CCS Directive
- Amendment to the London Convention allowing CO_2 storage
- Amendment to OSPAR Convention, allowing
- 2006 Guidelines in respect of the UNFCCC for accounting issues for international CCS projects
- Streamlining of the planning process in some jurisdictions, for example in the UK.
- IFC Guidance notes encourage the funding of CCS infrastructure.

Based on the progress to date in addressing legal issues, it is possible to be optimistic that most, if not all of the barriers above can be addressed. This will require concerted effort by CCS enthusiasts to consult with other stakeholders.

This study recommends

- Guidelines on the classification of dense and supercritical phase CO_2, and CO_2 streams with impurities from the capture processes are developed. This will allow regulators, developers and permitting authorities to make informed decisions on design codes, route selection, and proximity distances without facing uncertainty over classification.

- Discussions are facilitated between signatories to the London Convention to consider adopting an exemption for the transport of captured CO_2 for the purposes of geological storage only.

- Regulatory experts issue country-specific recommendations to national governments for the most appropriate jurisdictions.

- Guidelines are provided on the process for public consultations over CO_2 pipeline routes so that these are carried out in best practice, i.e. with the aim of minimising negative impacts.

- Further research be undertaken to identify the most appropriate regulatory and fiscal approaches to promote optimised CO_2 pipeline network development

7 LESSONS FROM THE OILAND GAS INDUSTRY ON THE FINANCING AND ECONOMIC REGULATION OF CO_2 PIPELINES

The previous chapter examines various constraints that current legal and regulatory arrangements may impose on the development of CO_2 pipeline, particularly, in the international context and makes specific recommendations. This chapter focuses on possible forms of economic organisation of the CCS chain that will facilitate efficient investment in, and efficient financing and economic regulation of, CO_2 pipelines. In doing so it draws on lessons from the organisation of pipeline transportation in the oil and gas industries.

7.1 Lessons from the oil and gas industry

Because CCS involves the pipeline transport of an energy sector output, considerable attention is being paid to the institutional, legislative, regulatory and contractual arrangements that govern natural gas transmission and the transmission of crude oil and petroleum products. This is a valid and useful exercise in its own right, since it makes sense to modify and transpose relevant elements of these arrangements and to avoid developing all arrangements from scratch.

However, any assessment of the development of oil or gas pipelines with a view to identifying specific arrangements or processes that might be of value in the development of CO_2 pipelines quite quickly reveals an amount of “baggage” that reflects changing political and policy (even ideological) preferences and priorities. It also, however, reveals the impact of developments in information technology that have allowed significant increases in the volume and frequency of transactions (thereby reducing transaction costs) and in the procedures for assessing and managing risk.

Underlying this “baggage” and innovations is the fundamental economics of oil and gas markets and the associated economics of pipeline transportation. It is worth while noting key lessons from this experience, but, first, it is necessary to examine the formation of costs and values in the CCS chain in relation to the corresponding formation in the oil and gas supply chains.

7.1.1 Price Formation

7.1.1.1 Oil

The existence of deep and liquid spot, forward and future markets in both well-defined crude blends and petroleum products means that, once the precise specification of a crude oil produced at any location is known, it is possible to determine its price (for example, in $/bbl or $/tonne) on a continuing basis with considerable accuracy. These crude blends provide a reference specification and a reference price to which all other crude qualities may be related. The discount or premium to the reference price at which a specific crude oil will trade is related to the extent to which its specification deviates from the reference specification and to the cost of transporting it to a refinery capable of processing that particular quality of crude oil.

7.1.1.2 Natural Gas

Only in the most developed gas industries and markets (and, again, only at relatively few locations) is it possible to determine the price of gas produced (in $/MMBtu or $/’000 cubic metres) with similar accuracy and confidence. For a gas industry at a relatively early stage of development it is frequently the case that the value of gas (and some associated indication of the price at which it may be sold) may be established only at the burner-tip (or point of consumption). Of course, it is possible to determine the final price on a cost-plus (or cost build-up) basis, but this rarely, if ever, leads to efficient consumption, investment and production decisions.

7.1.1.3 Carbon Dioxide

Under a "cap-and-trade" arrangement such as the ETS, or the approach being considered in the US, CO_2 will have a price when the cap reduces emissions of CO_2 below the level that would be emitted in the absence of a cap. Emissions may be reduced in two ways: when CO_2 that would normally be emitted into the atmosphere is certified as not having been emitted; and when CO_2 is captured and kept in isolation from the atmosphere.

7.1.2 The Main Forms of Transaction

The businesses (or firms) that operate in all industries enter into transactions between each other and, for those operating in the market for final goods and services, with consumers.
The three main forms of transaction are

spot market transactions;
bilateral contracting; and
formal vertical integration.

Each industry will rely on a particular mix of these forms of transaction. Specific features of the industry in terms of the frequency, costs and scale of transactions, the duration of the transactions and the risks associated with these transactions will determine the mix chosen. The valuation and pricing of oil and gas and the risks associated with large-scale, specific investments, the co-ordination of the activities performed in the oil and gas supply chains and the transaction costs associated with this co-ordination have driven the industries towards different degrees of vertical integration. We examine each of the supply chains in turn.

7.1.3 Crude Oil (and Petroleum Product) Transportation

In theory, an Exploration and Production (E&P) company could sell its crude oil at the well-head, but, in practice and to ensure a continuous supply, the closest to the well-head normally would be at the field collection (or blending) point of the gathering lines from a number of wells. Crude oil transmission starts at this point to

a refinery,
a railway depot and then to a refinery or to a port for sea transport to another transmission pipeline or to an overseas refinery,
a handling facility for water-borne transport, or
a port for sea transport to another transmission pipeline or to an overseas refinery.

The existence of alternative transport modes suggests that a transmission pipeline should not be able to establish a localised natural monopoly, but, in practice, the economies of scale captured by pipelines tend to render the alternatives non-viable. These modes tend to be economic when distances are short, the volumes are low relative to the capacity of large-diameter transmission lines and the period of transport is short relative to the 20+ years expected operational life-time of crude oil transmission lines.

7.1.4 The Specific Nature of Transmission Pipeline Investments

Investment in a transmission pipeline is termed "specific" in three respects. First, it is locked-in physically to a specific location between the field collection point and the point of crude oil delivery. Secondly, it is specific to the output of the field and has little, or no, value in an alternative use once the field is depleted. Thirdly, it is relationship-specific in that the transmission pipeline investor is providing a transmission service to the E&P company to deliver the output of the company's field. On the other hand, the E&P company is relying on the transmission service provided by the transmission pipeline.

The transmission pipeline will make the investment only on the basis that it can be assured of recovering the full investment including an appropriate return on investment over the period of pipeline service. Once the investment in the pipeline is made, it is a sunk cost and the economic cost from then on is the marginal cost of increasing or decreasing oil throughput volumes. But this ignores the annual depreciation charge (which recovers the initial investment) and the return that the investor needs to secure. These together comprise what is described as a "quasi-rent", since it is a payment over and above the economic cost. If the E&P company had a viable alternative means of getting its oil to a refinery it could "hold-up" the transmission pipeline and capture a share of this quasi-rent. In theory, the transmission pipeline would continue operations once at least some portion of this quasi-rent could be captured. In practice, the financing commitments underpinning the investment would be unlikely to allow this state of affairs to continue.

On the other hand, the transmission pipeline could "hold-up" the E&P company and capture a share of any surplus profits and of any quasi-rents being earned by the E&P company. Similarly, the transmission line could "hold-up" the refinery or refineries to which the crude oil was being delivered.

7.1.5 Recovery of Quasi-rents

None of the parties would willingly expose themselves to the risk of failing to recover these quasi-rents. Long term contracts or vertical integration provide the only viable solutions to minimise or eliminate the incidence of these risks. However, as pipeline investments become more specific, it is likely that the costs of contracting on a long term basis will increase more rapidly than the costs of vertical integration. Consequently, the oil industry globally is characterised by considerable vertical integration and widespread joint venturing.

Recent developments in the international oil industry suggest that the ability of E&P companies to monetise their oil production close to the field has reduced the inherent tendency towards vertical integration along the oil supply chain. However, what seems to be happening is probably tighter integration above and below the point of crude oil delivery. Over the last 10 years the major international oil & gas companies (IOGCs) have increased their focus on E&P activities and, via mergers and acquisitions, have consolidated their positions in this area. This has seen an emphasis on monetising oil reserves as near to the field as is feasible and it has placed considerable cost-reducing pressures on the activities downstream of the point of crude oil delivery. Refining capacity has been rationalized and all downstream investments have been squeezed. Some refining capacity, petroleum product storage and distribution facilities have been sold and been replaced by contracts for their services with the new owners.

What seems to be clear is that E&P companies will seek to integrate any transport facilities downstream of production to the point of delivery of crude oil so as to maximise the value of production. In the absence of an ability (or a desire) to integrate the transport and other downstream facilities all along the supply chain, they will seek to participate on a JV (or a long term contractual) basis to control the costs incurred and to maximise the netback to the field.

7.1.6 Natural Gas Transportation

The fact that the value (and price) of natural gas, typically, is established further down the gas supply chain than it is for oil suggests that, for the reasons discussed above, the degree of vertical integration should be greater than it is for oil. And, in general, this has proved to be the case.

Some industries have developed on the basis of complete vertical integration with one company responsible for all the activities in the gas supply chain, but this is becoming increasingly rare. One reason is that the investment and technology provided by IOGCs is required at the E&P stage and, increasingly, these IOGCs will wish to market directly their share of the gas produced.

7.1.7 The "Integrated Transmission & Supply" Model

In the last 40 years the "Integrated Transmission & Supply" model emerged as the dominant economic organisation structure for national gas industries. All Western European countries that developed their national natural gas industries during the 1960s and 1970s adopted some variant of this model.

The Integrated Transmission and Supply business is in the centre of the figure. This is the national company (in most cases, 100% state-owned) which has a monopoly on gas transmission and storage, an exclusive right to purchase and import gas and an exclusive right to supply large volume consumers connected directly to the transmission system and distribution companies (DistCos).[37] There may be a national oil and gas company which competes with internal and external producers and suppliers to supply gas to the integrated transmission and supply company.[38] There is also a clear demarcation between upstream production and supply of transmission pipeline quality gas and the downstream transmission, storage, distribution and supply of gas.

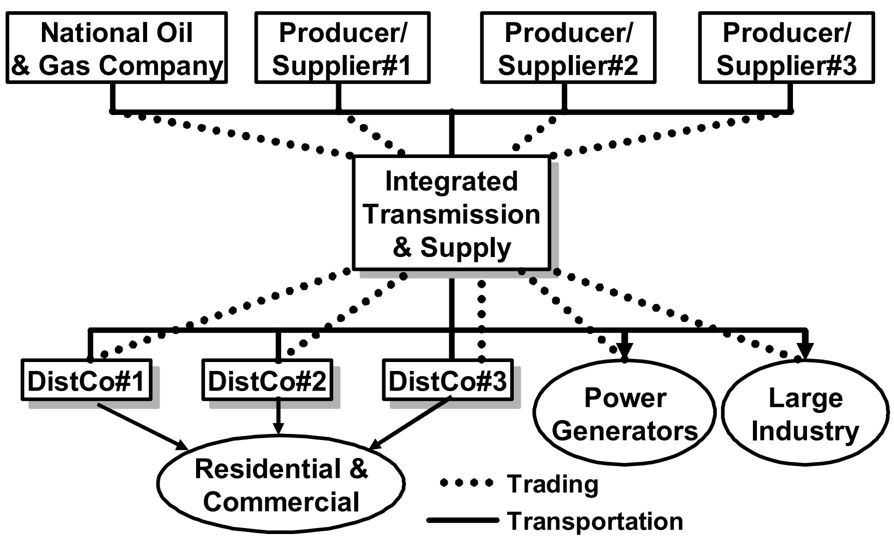


Figure 22 Integrated gas transmission and supply model

The internal suppliers (i.e., the producers operating within the national jurisdiction) had no choice of buyer. They could sell their gas to the integrated transmission and supply company at the price determined by the integrated company as the sole buyer or leave it underground. External suppliers, in principle, could seek out a choice of national integrated companies, but geography and the cost of long-distance (or sub-sea) pipeline transmission tended to restrict this choice. Over time, as the demand for natural gas increased beyond the delivery capacity of indigenous supplies, the potential for, and viability of, large-scale external supplies and significant investments in long-distance pipeline transmission and the liquefaction and

[37] Some national industries (e.g., the UK and France) had a complete vertical integration of transmission and distribution; most others maintained a commercial and ownership demarcation. However, even with this demarcation, the distribution companies were compelled to buy their gas from the integrated transmission and supply company. This could be described as "vertical integration by exclusive contract".

[38] Some national oil and gas companies have been privatised and absorbed by other companies (e.g., Britoil in the UK); others have been partially privatised but retain a strong national and international presence (e.g., ENI in Italy).

shipping of natural gas emerged. The basic economics of these developments are considered in Box 1.

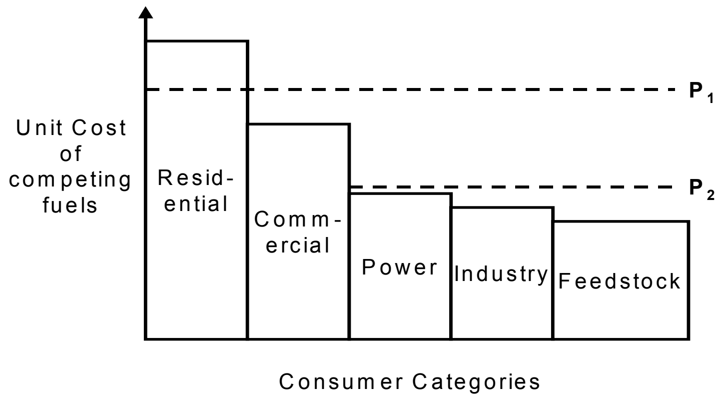
This form of economic organisation reflected the nature of gas price formation, the scale of dedicated investment and the risks to which gas industry participants were exposed.

7.1.8 Transmission Investment Specificity and Quasi-rents

The issues of the specific nature of transmission investment and the recovery of quasi-rents discussed above for crude oil transmission also arise for natural gas, but the means of resolving these tended to differ from those employed in the oil industry. Numerous factors may be considered that would account for these differences (both between the oil and natural gas industries and among countries and regions), but two are worthy of further consideration.

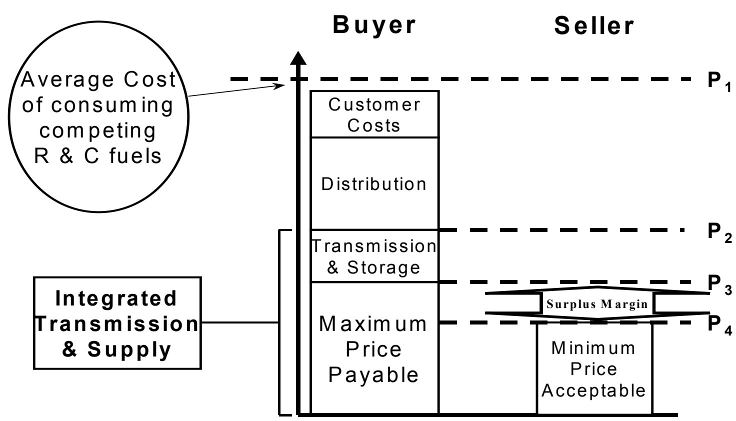
Box 1: The Economics underpinning long-distance natural gas transmission

The gas price formation under the Integrated Transmission & Supply model is described as Market Value/Netback pricing. The first step is to establish the Market Value of gas and this and is illustrated in the following figure.



The maximum value of gas in each consumption sector or application is the unit cost of consuming the fuel most likely to be displaced by gas in that sector or application. This provides an estimate of consumers' maximum willingness-to-pay (WTP) for natural gas and it would be necessary to set the price below this level to provide an incentive to convert to natural gas. In the exhibit, P_1 is an estimate of the average unit cost of fuels competing with gas for residential and commercial (R&C) consumers who would be supplied from distribution systems. P_2 is an estimate of the average unit cost across the entire market available to natural gas.

The second step is to relate this to the cost of internal supply to provide an estimate of the maximum supply or import price that the integrated transmission and supply company could afford to pay. This is illustrated in the following figure.



Box 1: (continued)

For a given volume of gas the integrated transmission and supply company will estimate the maximum average prices for R&C, P_1, and for the market as a whole, P_2, which will cover the full costs of internal supply (transmission, storage, distribution and customer-related costs). This calculation will provide an estimate of the maximum price, P_3, which it can afford to pay for gas. It will also attempt to derive an estimate of the price at which the seller will be able to deliver gas to the national border (including recovery of the transmission investment incurred by the seller). The seller will do a similar analysis and derive an estimate of the minimum price acceptable at the national border, P_4. This will form the basis for the price negotiation between the buyer and the seller.

P_3 must be greater than P_4 or there will be no basis for negotiation and the gap between the two is the surplus margin available in the gas supply chain. In practice, the buyer and the seller will share this surplus margin and the shares captured by each will reflect the relative market power they exercise and their negotiating capability.

This description has been presented in a simple static formulation. In practice the analysis would project the costs and values over time and a price indexation mechanism would be developed which would relate the price of gas in the supply contract to the prices of the fuels being displaced by gas. This approach underpinned the negotiations of gas supply contracts during the 1970s and 1980s between the major European integrated transmission and supply companies (e.g., Gaz de France, ENI, Distrigaz, Ruhrgas) and the major external suppliers (e.g., Statoil, Gazprom, SONATRACH).

This approach allocated most of the volume risk to the buyer and the price risk to the seller. It provided a means of securing the large-scale, dedicated investments in gas production and long distance export pipelines in Russia, in the development of major gas fields and sub-sea export lines in the Norwegian sector of the North Sea and in the construction of LNG facilities and export pipelines in Algeria. It was characterised by vertical integration upstream of the EU border, by a combination of vertical integration and supply exclusivity downstream of the EU border and by bilateral contracting between the external supplier and the integrated transmission and supply company. Given the scale of the dedicated, specific investments involved and the risks to which the parties were exposed, this is entirely in line with what economic theory would predict and is consistent with the discussion of the oil supply chain above.

The surplus margin as illustrated is simply a portion of the resource rent that may be captured. The simplified components of the cost and value of gas presented include a number of sub-components that, when combined with the surplus margin identified, comprise the total resource rent available in the gas supply chain.

Gas Supply as a Utility Service: in many of today's developed economies the supply of gas to households and businesses sometimes predated but, generally, paralleled expansions in the supply of electricity. This gas was manufactured at centralised urban depots (frequently described as "town gas"), initially from coal, but later from naphtha, and supplied on distribution or reticulation systems. In most countries this was treated as a utility service and subject to varying degrees of technical, safety and economic regulation and control by national and local authorities. With some modification this approach continued to be applied following conversion to, or the introduction of, natural gas. The principal rationale for economic regulation is to ensure that the gas distribution and supply business, as a local monopoly service provider, does not succumb to the inherent incentives to overcharge and/or reduce the quantity and quality of service. But it also provides a strong assurance of investment recovery.

In contrast, for the oil industry, companies compete in the sale of petroleum products to final consumers and this tends to minimise the requirement for economic regulation.[39]

Introduction of Natural Gas: In many countries, the introduction of natural gas, which required large-scale investment in transmission and in the conversion and expansion of existing distribution networks, was accompanied by increased state involvement. The predominantly state-owned integrated transmission and supply businesses that emerged had exclusive rights to purchase, import, supply and transport gas. This provided an assurance of revenue recovery that allowed these businesses to enter into long term contracts for supply and to invest in pipelines (and associated facilities) without corresponding long term purchase contracts or long term commitments to pay for the transmission capacity constructed. Much of this transmission capacity was constructed in anticipation of demand on the basis of the assurance that final consumers, ultimately, would pay for it.

In contrast, in the US, although the natural gas industry was developed initially with integrated pipeline and supply businesses (supplying Local Distribution Companies (LDCs) and directly connected, large volume consumers) subject to quite onerous federal and state-level regulation, the entire industry has been restructured over the last 30 years to facilitate competitive markets in gas and pipelines. This development deserves more detailed consideration as it has important lessons for the development of CO_2 pipelines.

7.1.9 The Transition to Competitive Markets in Gas and Pipelines

It is generally accepted that the North American market (comprising the USA and Canada, and, increasingly, Mexico) presents the most advanced and complete form of competition in gas and pipelines. This competition in gas and pipelines will emerge when four key market mechanisms are in place. Absent any of these elements and the market will not function effectively.

These four market mechanisms comprise:

- Primary market in transmission capacity;
- Liquid physical spot and forward markets in gas;
- Secondary market in transmission capacity; and
- A market in gas futures.

These are discussed in turn.

7.1.9.1 Primary Market in Transmission Capacity

The inception of a primary market in transmission capacity requires the efficient and effective definition, pricing and allocation of existing transmission capacity subject to sector-specific regulation. The inter-state (or inter-provincial) long-line pipelines were constructed on the basis of long-term contracts between the transmission pipeline companies and gas producers

39 The experience of regulation of oil pipelines in the USA is of some interest, but of limited relevance. The Hepburn Amendment (1906) of the Inter-State Commerce Act required inter-state oil pipelines to offer service on a common carriage basis. This meant that they had to provide service to all comers. If there were insufficient capacity, volumes per shipper would be reduced pro-rata. If there were a sustained shortage of capacity, new capacity would be added. The Hepburn Amendment was in response to observed restraints of inter-state trade and shipping of oil and to the dominance of the Standard Oil Company which was eventually broken up using the Sherman Anti-Trust Act in 1911. The pipelines were subsequently subjected to regulation using an oil pipeline cost index. The common carriage basis and relatively light-handed regulation of inter-state oil pipelines continue to this day, but they are largely irrelevant in the international context given the degree of vertical integration, joint venturing and competition for the custom of final consumers that characterise the global oil industry.

who wished to get their gas to market and were subject to federal regulation. The pipeline companies entered into bundled transmission and supply contracts with Local Distribution Companies (LDCs) and other large volume consumers. When unbundling of the transmission and supply activities was encouraged on a voluntary basis in 1985 and, eventually, mandated in the US in 1992, it was possible, initially, to align the Maximum Daily Quantity in the previously bundled supply contract with the associated pipeline capacity reservation and this provided the basis for firm, well-defined, long-term transmission capacity rights which could be traded. Pipeline tariff regulation is based on costs actually incurred and there are detailed rules and regulations governing the derivation of tariffs. Due to the long-line nature of the inter-state pipeline systems distance-related or zonal charging is common in the primary market.

The key innovations that encourage efficient investment in, and efficient use of, pipelines comprise the unbundling of pipeline and supply activities and the separation of "ownership" of the pipelines and "ownership" of the capacity provided by the pipelines. Unbundling is intended to ensure that the pipeline business has no incentive to discriminate unjustifiably between different users of the pipeline once they comply with the agreed contractual terms and conditions of pipeline capacity use. The separation of ownership provides the pipeline owner/operator with a regulated assurance of full recovery of the investment incurred and provides pipeline users who enter into contracts for a share of the pipeline capacity to use or trade this capacity as they see fit subject to agreed pipeline operation and safety requirements.

The benefits of these innovations may be seen most clearly when a requirement for new investment arises. If, for example, a number of gas producers identify an opportunity to produce and transport increased volumes of gas to the market and existing pipeline capacity is not sufficient, the pipeline company[40] will hold an "open season" which will allow producers and other parties interested in transporting gas to declare their interest in reserving capacity in a new pipeline (or in a combination of new pipes and reinforcements (e.g., compression and looping) of the existing pipeline system). This will allow the investment to be sized efficiently to match the capacity demand of the various interested parties prepared to commit to the reservation of capacity. It should also allow the capture of any economies of scale that might arise and this will benefit the parties committing.

These benefits may also be seen when, for example, a new or existing user of the pipeline seeks to inject additional supplies of gas at a new location on the pipeline. Once the sponsor of the pipeline connecting these new supplies complies with the normal pipeline consent and approval procedures, the pipeline company has no right to prevent the connection being made provided that the user of the connecting pipeline is able to secure capacity, or is prepared to commit to reserving the required increase in capacity, on the existing pipeline downstream of the connection point. This may be available from existing pipeline users, but, if not, the pipeline will be required to make an offer to invest in providing the required capacity at incremental cost. The user of the connecting pipeline is free to solicit offers from other pipeline investors to provide this additional capacity.

All of these features ensure that there is effective competition in pipeline investment and the provision of capacity.

7.1.9.2 Liquid Physical Spot and Forward Markets in Gas

The Market Value/Netback approach to gas trading and pricing (described above) allows prices to change in a formulaic and indexed manner while gas flows are required to adapt

40 There is nothing to prevent a number of pipeline companies holding "open seasons" for the prospective pipeline users. This helps to ensure efficient competition in investment. In general, the existing pipeline company may be able to increase capacity on the existing system at a lower incremental cost and this will close out opportunities for completely new build options. But this may not always be the case; combinations of compression and looping may have maximised the available capacity and there is no option but to construct a new pipeline system.

rapidly to changes in demand and supply. Costs and values may diverge for considerable periods of time. Spot markets allow prices, volumes and gas flows to respond to changes in demand and supply so that prices continuously reflect the cost and value of gas. When there is sufficient liquidity the forward price curve can inform decisions on investment in production and transmission capacity

Spot markets in North America tended to emerge at hubs close to production areas where many pipelines are interconnected (producer hubs) or close to major demand locations (market centre hubs). These hubs provide a wide range of services (including electronic trading of standardised contracts) and the most liquid hubs have access to high-delivery storage facilities. The most well-known (and liquid) hub is the Henry Hub in Louisiana close to the margin gas supply basin in the Gulf of Mexico.

7.1.9.3 Secondary Market in Transmission Capacity

Allowing gas traders to trade the primary transmission capacity they have reserved will lead to a more efficient allocation of capacity on a day-to-day basis and, in the absence of constraints, congestion and the exercise of market power, will permit convergence of gas prices at specific trading locations to determine a single price for the entire wholesale market. A sustained increase in the price in the secondary market will signal the requirement for additional transmission capacity. Pipeline companies typically employ Electronic Bulletin Boards (EBBs) to post bids and offers for released pipeline capacity.

In the US concerns about the hoarding of capacity and the associated abuse of market power delayed the introduction of unregulated trading in secondary capacity. However, once the incremental pricing of new capacity was mandated, positive differentials emerged between the price of secondary capacity and the regulated tariffs and this provided the necessary incentive to capacity-holders not using, at least some of, their capacity to release it to other pipeline users so as to earn these differentials.

Increased spot market trading and the growth of the secondary market in transmission capacity have encouraged market focus on the “basis differential”. The basis differential is simply the difference between the spot prices of gas at two connected hubs and will inform locational trading decisions. Numerous trade publications report prices and differentials.

In addition, the basis differential represents the market value of transporting gas between the two hubs and, in the absence of other factors, should be unchanged in the short term. Volatility in the basis differential will indicate the impact of market-moving forces and the analysis of this volatility provides useful market information to traders.

7.1.9.4 Market in Gas Futures

Daily trading of gas at physical locations will lead to considerable price volatility. Traders will require risk-management tools to deal with this volatility. The demand for these tools provides the basis for a futures market referenced to the spot price at the most liquid trading location. Gas futures are financial instruments. They do not involve the physical delivery of gas. The trade is in risk and volatility and it is subject to financial regulation.

7.1.9.5 Summary

The successful transition to competitive markets in gas and pipelines in the US (and being extended throughout North America) has been predicated on the development of efficient and competitive markets in pipeline investment and in pipeline capacity. A major beneficial outcome of these developments is a reduction in the extent and intensity of pipeline regulation. Competitive markets in pipeline investment provide far more effective discipline on pipeline tariffs than regulation which is always and everywhere a second-best solution.

7.1.10 EU Experience of the Transition

In principle, the EU has been pursuing this transition process since the early 1990s; in practice, the outcome stills falls far short of EU-wide competitive markets in gas and pipelines. And this is despite the enactment of three successive packages of EU primary legislation. Numerous reasons may be advanced to account for this. Many relate to the organization and ownership of the gas industry – and to the strategic interests of the dominant incumbent market participants - in some of the larger national markets. However, it is difficult to avoid the conclusion that the proximate cause is the failure to define and adapt the key market mechanisms developed in the US gas market.

And to compound this failure the EU is promoting the widespread application of a mechanism for defining and pricing capacity on gas transmission pipelines – Entry-Exit – that, despite being promoted as a means of promoting gas trading and efficient use of, and investment in, pipelines, is proving to be an extremely effective means of preventing the emergence of the key market mechanisms required to achieve these objectives.

Entry-Exit is typically applied to a well defined onshore transmission system with clear gas entry points and gas off-take (or delivery) points – or zones. Again, typically, the complexity of the transmission network means that it is not always possible to track gas flows from a single entry point to a single exit point on a sustained basis. Although it may be possible to do so on some occasions, a change in the pattern of flows on the system may result in gas being delivered to the exit point from another entry point. This is often called delivery by displacement. The idea of separating the capacity to evacuate gas from an entry point from the capacity to deliver gas to the exit point arose in the context of transmission pricing. At the same time the concept also emerged of the gas input at entry points being delivered to a notional hub (or national balancing point)[41] from which it would be delivered to the exit points.

In addition to providing the basis for transmission pricing, Entry-Exit with this notional hub provided the (virtual) location for measuring and reconciling imbalances between inputs and off-takes on the transmission system. Very quickly it emerged as the virtual location for trading gas – as indicted in the figure.

Trading at the hub (on a within-day and day ahead basis) reveals the gas prices required to maintain an on-going transmission system balance (for system operational, safety and integrity purposes) and a demand-supply balance.

Apart from the physical locations of entry points and exit points (or zones), this definition of capacity abstracts completely from the underlying configuration of the pipeline system. In contrast to the precise definition of pipeline capacity on a point-to-point basis in the US and the decentralization of pipeline capacity use and investment decisions, the owner/operator of the pipeline system has almost complete control. The owner/operator determines the split between entry and exit capacity and prices all capacity on the basis of its estimates of the long run incremental costs of increasing input and off-take volumes by the same amount at each combination of entry and exit points (in the context of its view on the overall pattern of flows on the pipeline system). The only effective external constraint on its behaviour is the requirement to scale the resulting entry and exit tariffs to match the allowed regulatory revenue.

When this approach is combined with a continued unwillingness to enforce effective separation of pipeline and supply activities and with a lack of transparency regarding pipeline capacities, constraints and flows, pipeline users are prevented from participating in the gas market. Transmission tariffs should aim to provide a means of recovering sunk costs and fixed operating expenditure in a reliable and predictable manner. No centralized tariff-design mechanism will generate price signals that ensure efficient use of capacity. Seeking to incorporate this feature is futile.

41 The UK National Balancing Point (NBP) is probably the best-known example.

This approach deters the long-term commitments that would recover the sunk costs of pipeline investment, maintains centralization of investment decision-making (thereby preventing the emergence of an efficient market in pipeline investment, conveys distorted price signals and suppresses more effective and relevant secondary market price signals. It is strongly recommended that this approach not be applied in the development of CO_2 pipelines.

7.1.11 Summary

The following table summarises the foregoing discussion by evaluating four distinct pipeline markets against five criteria.

	Crude Oil & Petroleum Product + Upstream Gas	US & EU Gas Pre Deregulation/ Liberalisation	US Gas Post Deregulation	EU Gas Post Liberalisation
Organisation of Investment	Vertical Integration or coalitions/JVs of market participants	Pipeline companies linking producers & buyers (US); exclusive rights to transmit & supply (EU)	Unbundled pipeline companies, independent interconnections, competitive provision of capacity	Centralised control of investment subject to (not very effective) regulation
Assurance of Investment Recovery	Contractual framework	Regulated cost recovery (US); granted monopoly (EU)	Long-term, tradable, clearly-defined capacity contracts	Primarily via regulation but uncertainty exists
Capture of Economies of Scale	Incentives to form coalitions	"Rolled-in" incremental costs (US); building in advance (EU)	Mandatory "open seasons" and incremental pricing of capacity	Hindered by regulatory uncertainty and lack of long term contracts
Efficiency of investment & operation	Common interest in cost reduction and performance	Potential to capture consumer surplus	Users decide investment in, and use and trade of, capacity	Entry-Exit pricing suppresses price signals
Role of Government	Regulated "common carriage" (US); mandatory requirement to serve new users; limited regulatory oversight (EU)	Cost-of-service regulation (US); grant of exclusive rights (EU)	Reduced primary regulation as pipe-to-pipe competition emerges and pipeline capacity is traded in liquid markets	Regulatory dominance, but investment policy concerns exist

This overview of the development of pipelines and markets in pipelines in the oil and gas industries generates one important observation and two broad, but generally applicable, conclusions.

The observation is that the extent and intensity of pipeline regulation across jurisdictions and over time outlined in final row in the table. Economic regulation is less intrusive and intensive when and where market participants are permitted and encouraged to form coalitions and collaborate (EU crude oil and petroleum product pipelines and upstream gas pipelines) or the regulatory authority promotes and facilitates the emergence of a competitive market in pipeline investment (downstream gas in North America).

The first conclusion is that, in the context of dedicated, frequently large-scale and long-term investments, oil and gas market participants will seek solid assurances of full investment recovery (including an appropriate risk-related rate of return). And this seems to be the case particularly for pipeline investments. This tends to lead to the formation of coalitions and joint ventures in the oil industry and to vertical integration in the gas industry.

The second conclusion is that the economic organization of the oil and gas supply chains is determined by the existence of, and the ability to capture, surplus value in the supply chains. All oil and gas market participants deny the existence of surplus value, the motivating impact of its existence and the desire to capture a share, but its importance is revealed in the forms of economic organization that have emerged. In the oil industry, when more than one party is involved, investment in, and the operation of, pipelines is designed to ensure the recovery of the investment, the minimisation of cost and the removal of any ability to capture surplus value in this part of the chain. In the gas industry there is a tendency to opt for vertical integration both upstream and downstream of the point where pipeline supply contracts are agreed. This is designed to ensure recovery of investment and to prevent leakage of the share of surplus value negotiated.

The competitive markets in both gas and pipelines that have emerged in North America provide assurance of investment recovery and compete away any surplus value that emerges. The EU is still a long way from replicating this and there are justifiable doubts as to whether or not it is either feasible or desirable. Via merger and acquisitions many of the previous dominant incumbents in the larger national electricity and gas markets are forming pan-European vertically integrated operations along the gas and electricity supply chains. The Directorate-General for Competition (DG COMP) of the European Commission is progressively enforcing competition law to compel these entities to divest their networks to allow transparent and non-discriminatory access. Not surprisingly the efforts by the Directorate-General for Energy and Transport (DG TREN) to legislate for this unbundling have been met with considerable industry and national government opposition. The resulting legislation, inevitably a compromise, is unlikely to foster the emergence of competitive investment in gas pipelines. As a result, regulation is required to be continuously more intensive and intrusive.

7.2 CO_2 Pipeline Development Options

Having given some consideration to the promotion, and means of recovery, of efficient pipeline investment in the oil and natural gas industries, it is now possible to identify the factors that are likely to affect the development of CO_2 pipelines and the efficiency with which they are developed. Given the scope of this study, the over-riding objective is to identify the means of minimising of the cost of CO_2 transport. This requires both efficient investment in the provision of capacity and efficient use of this capacity once constructed.

There is no intention to propose that “one size fits all”. Circumstances will arise in terms of the size and locations of emitters, the phasing of emissions, distances to sinks, the availability, location and capacity of sinks and other factors which will have a major bearing on the configuration and phasing of investment in CO_2 pipelines. However, there are clear lessons coming from the experience of the natural gas industry (and, by default, from the oil industry) of the benefits of creating the conditions for an efficient market in pipeline investment and for a liquid market in pipeline capacity. National Economic Research Associates (NERA) demonstrated this comprehensively in a report for the UK Department for Energy and Climate Change (DECC).[42]

The natural tendency towards vertical integration (as a means of reducing both risk and the number (and costs) of transactions – and to capture any surplus value) will always exist, but the benefits of competitive markets are significant and the potential to facilitate the emergence of these markets should be explored in all circumstances. Even when vertical integration from capture to storage may be deemed the most appropriate approach, it still makes sense to examine the potential to modify these arrangements to permit competition in pipeline investment.

[42] NERA, “Developing a Regulatory Framework for CCS Transportation Infrastructure (Vol. 1 of 2)”, prepared for DECC, 11 June 2009.

However, when assessing the potential to establish this approach to investment in, and operation of, CO_2 pipelines it is necessary to take three factors into account.

These comprise:

- The extent and nature of government support required to achieve the independent financial viability of CCS;
- The likely economic organisation of the CCS chain; and
- The incidence of projects that may not permit competitive investment in pipelines.

7.2.1 Extent and Nature of Government Support

It is generally accepted that the value of CO_2 emission permits under a cap-and-trade scheme which is equivalent to the costs avoided by a CO_2 emitter using CCS will not cover the full costs of CCS during its early stages of development. In addition, there is the issue of identifying and selecting the most cost-effective capture technology. These issues have been addressed by the Electricity Policy Research Group of the University of Cambridge in a report for the UK Department of Energy and Climate Change (DECC).[43] The report examines the risks associated with the selection of demonstration projects in the context of the two CCS demonstration funding mechanisms being proposed by the EU. The report concludes that Technology Category Auctions should be used in the selection of demonstration projects that will be supported to ensure the benefits of diversity rather than replication. It also concludes that national government support in excess of that being provided by the EU funding mechanisms should be provided to ensure that the number, scale and full operation of demonstration projects should be sufficient to advance CCS towards commercialisation.

The report focuses on the development of CCS demonstration projects in the EU; various mechanisms are being developed to support demonstration projects in other OECD countries (and in non-OECD countries). And the report, quite understandably, focuses on capture technologies; the pipeline transport and storage of CO_2 are proven and scalable technologies.

However, the report largely abstracts from the form of economic organisation of the CCS chain.

7.2.2 Likely Economic Organisation of the CCS Chain

During the demonstration phase the objective is to identify and propagate the capture technology (or technologies) that will allow CCS to achieve commercial viability. Commercial viability is defined as a situation not requiring direct or indirect financial support from governments. There is no guarantee that this state will be reached within the timescale envisaged, but it is assumed that it is in the public interest in all countries promoting CCS to ensure the costs and benefits of CCS are internalised to the greatest extent possible so that government financial support may be withdrawn.

The withdrawal of government support implies that the CCS chain participants will have the tools to address the risks that will arise. It also implies that the potential to capture surplus value in the CCS chain will arise.

In addition to assurances on investment recovery the potential to capture surplus value (as we have seen in the oil and gas supply chains) is a key motivation for private sector participation. Apart from the specific support mechanisms for CCS demonstration projects the current EU draft directive revising the ETS arrangements for Phase III from 2013 envisages not awarding any EUAs to power generators (expect for some heat producers). The cost of purchasing EUAS that is avoided by generators opting for CCS is expected,

43 Cambridge University Energy Policy Research Group, "Carbon Capture and Storage (CCS): Analysis of Incentives and Rules in European Repeated Game Situation", 1 June 2009.

eventually, to cover the full costs of CCS. On the other hand, sink holders will be explicitly included in the ETS scheme as entities not requiring EUAs. They will have a legitimate claim to receive EUAs for the CO2 they safely store.

This sets the scene for three options:

> ***Collaboration***: emitters and sink-holders enter into a JV to capture, transport and store CO_2 and to share the value of the emission allowances between them;
>
> ***Negotiation***: the emitters take responsibility for capturing and transporting CO_2 to a hub; sink-holders take responsibility for transporting CO_2 from this hub, injecting and storing it; the emitters and sink-holders negotiate the share of emission allowance value to which each party is entitled. This option has two possible further variants
> a. sink-holders taking responsibility for transmission from the point of capture, and
> emitters taking responsibility for transmission to the gathering point for injection.
> These generate three possible locations for the negotiations between the emitters and the sink-holders;
>
> ***Unbundled, competitive transmission investment***: sink-holders and emitters negotiate a price that the sink-holder will pay to the emitter for delivering specific volumes of CO_2 at a specific location (could be the entry point to the pipeline, a physical hub where a number of pipelines interconnect, or the sink-holder's gathering point for injection) and both parties engage pipeline companies to hold "open seasons" to provide the transmission capacity. This option has the potential for the trading of CO_2 abated at a physical hub and with a basis differential between the traded price and the EUA price.

It is important to note that a completely new pipeline business (which is what CO_2 transport in response to climate change price signals will be) has never been initiated using the competitive investment model. It has only emerged through the reform of an existing industry. This does not mean it is impossible - and the benefits of doing so are clear, but, in the context of the huge uncertainties surrounding CCS, it is unlikely to be the first choice - particularly at the demonstration and early development stages of CCS.

This suggests that the first two options will dominate the thinking of industry participants and, of these, it may be that the first, "collaboration", option will be preferred. Collaboration will provide the heft and cohesion to negotiate with governments to extract concessions and subsidies. However, in terms of protecting the public interest, reducing localised monopoly power, ensuring efficient investment and operation and encouraging efficient network development this option performs poorly.

The second option should perform better as it may curtail the power of the emitters and sink-holders in negotiations with governments regarding the nature and extent of public support required. It also provides the potential to extract an unbundled pipeline business as the industry approaches independent commerciality - leading to the competitive provision of investment (Option 3). It may also be possible to extract an unbundled pipeline business from Option 1, but it is likely to prove more difficult.

This leads us back to just two principal options each including varying degrees of potential to incorporate an evolution to competitive investment in pipelines.

Under a competitive investment model the use of "open seasons", as described previously, provides an effective means of engaging prospective emitters with prospective pipeline investors. The engagement may be initiated from either side of the supply-demand equation, but the open season is arranged, in most cases, by a pipeline business which is aware of demand for additional capacity and seeks to establish the extent and firmness of the demand. Prospective emitters which have the potential to form a cluster should have an incentive to form an informal coalition to pool their demand for capacity and benefit from the resulting economies of scale.

This provides the basis for pipeline sizing and investment phasing and, in the event of agreement in principle between the pipeline business and prospective emitters, should provide the basis for the signing of long term contracts for pipeline capacity that will allow financing for the investment to be secured and for construction to commence (subject to the normal planning and consent requirements).

In general, the pipeline will be sized to provide the contracted capacity and additional capacity may not be provided without incurring additional costs. In some instances, prospective emitters might not have been prepared to commit to reserving and paying for capacity for a variety of reasons and subsequently wish to connect to the pipeline and to secure transport capacity. In other instances new prospective emitters may have located their plants adjacent to the pipeline subsequent to its construction.

In these instances, the pipeline will not have sufficient capacity to transport CO_2 from these emitters – unless existing users have unused capacity that they are prepared to release. There is a strong case for imposing a requirement on the pipeline to allow the connection of these emitters and to offer the capacity they require on the basis of the incremental costs incurred by the pipeline (provided, of course, that the sinks to which the pipeline system is connected have sufficient capacity to store the additional emissions and contractual arrangements are in place between the emitters and the storage operators).

If these prospective emitters are not satisfied with the cost of the additional capacity offered by the pipeline they will retain the option to solicit offers to provide the required capacity from other pipeline investors. While an existing pipeline is able to offer additional capacity at an incremental cost lower than the cost of constructing a separate pipeline, the pipeline will enjoy a temporary local monopoly and economic regulation will be required.

7.2.3 Projects predisposed towards Vertical Integration

It is possible to conceive of numerous prospective CCS projects comprised of a single large volume emitter (without emitters in the vicinity having a scale of emissions appropriate for incorporation in the project) and a single large sink that is available and sufficient for storage. In these cases, vertical integration may make sense as the emitter has every incentive to minimize costs all along the CCS chain. In addition, it is likely that, for CCS demonstration projects – comprised of a single source to a single sink - the initial emitter will seek to develop the project from capture through to injection and storage on a vertically integrated basis.

It is also possible to envisage projects where a transition from vertical integration to competitive provision of pipeline investment could be appropriate. For example, in the case of a demonstration project developed on a vertically integrated basis, if there are other prospective emitters in the vicinity and the chosen sink has (or adjacent sinks have) sufficient space to accommodate these other emissions, it may be possible to outline transitional arrangements.

7.3 Implications for the financing of CO2 pipeline investments.

Much of the foregoing discussion focuses on the various approaches to facilitating efficient investment in CO2 pipelines in the developed economies – and within well-defined jurisdictions. As a general rule, if the economic organisation and the regulatory arrangements are appropriate and the projects under consideration are economically viable, it will be possible to secure financing. In a global context and for projects that cross international and jurisdictional boundaries, more wide-ranging and complex challenges emerge. We now consider these issues and the agencies and mechanisms that, in most circumstances, assist in meeting these challenges, but, on occasion, do not.

7.3.1 World Bank and International Finance Corporation Financing

World Bank and IFC funded projects are required to be developed in line with the IFC's Environmental, Health and Safety Guidelines. The guidelines present good practice guidance on all stages of project development, covering both environmental and social considerations. In terms of general development, Guidelines are provided for Environment, Occupational Health and Safety, Community Health and Safety, and Construction phases of projects; overall acceptability of project design is determined through specific Performance Standards regarding various aspects of project design. This combination is designed to promote good practice for project development where local regulation may be absent or poorly enforced. Where levels are higher than imposed by the IFC Guidelines, projects are expected to adopt whichever is more stringent. The Performance Standards are designed to set benchmark performance standards for new developments that are considered by the IFC to represent currently achievable levels with existing technology at reasonable cost.

In the context of CCS, this presents two considerations where WB or IFC funding is involved:

- Firstly, environmental, social and health impacts of project development must be assessed; and,
- Second, the overall design considerations fall in line with the relevant Performance Standard(s), and the attendant Guidance Notes thereunder.

In terms of pipelines, the first condition is fulfilled through the preparation of and environmental and social impact assessment in accordance with the following:

- Performance Standard 1: Social and Environmental Assessment and Management System
- Performance Standard 4: Community Health, Safety and Security
- Performance Standard 5: Land Aquistion and Involuntary Resettlement
- Performance Standard 6: Biodiversity Conservation and Sustainable Natural Resource Management
- Performance Standard 8: Cultural Heritage

These would be subject to scrutiny by the public and IFC/World Bank Boards. Where specific concerns are raised, projects are subject to review and potentially redesign or termination. In terms of the impacts for CO_2 pipeline developments, this means that any pipeline involving World Bank of IFC finance will need to be carried out following the guidance. This is likely to be most applicable to CO_2 pipeline developments in developing countries where specific legislation relating to CO_2 pipelines is locally absent.

The World Bank has lent $5-9 billion/year for infrastructure projects in energy, transport, telecommunications, water supply and sanitation. The Bank claims that the economic rates of return for most of its projects have been satisfactory, and there have only been a few unproductive, wasteful ‘white elephant’ projects[44]. World Bank experience perspectives on three pipeline projects are particularly noteworthy:

- The Chad-Cameroon Petroleum Pipeline
- The Bolivia-Brazil Gas Pipeline Project ($130m)
- The Baku-Tbilisi-Ceyhan (BTC) Oil Pipeline Project

In Chad, the World Bank stipulated that investment in the petroleum pipeline was coupled directly to a legally binding sustainable development framework – whereby future revenues were directed at health, education, infrastructure, and rural development. When the legal framework was amended in Chad, the World Bank suspended its financing.

The Bolivia Brazil Gas Pipeline Project (approved in 1997) presented great challenges due to complex social impacts. The challenges arose from the cross-boundary nature of the project, involving a gas producer in a small economy (Bolivia) and a huge potential demand in a large country (Brazil), the execution of a major engineering construction over 3,000 km, cutting

[44] These typically result from too optimistic demand estimates, insufficient stakeholder surveys, over-engineered solutions that are expensive to maintain, excessive loan conditionality, project complexity.

across more than one hundred small communities in Bolivia and Brazil, including indigenous communities, small rural villages, small towns and large municipalities. The project is seen by the World Bank as a success in terms of stakeholder communication and management. Negotiations with the communities and individuals on route and acquisition minimized social impacts from rights of way. The impacts associated with the construction works were controlled and managed. These included the location of worker camps; enforcement of safety measures and workers' code of conduct, and responses to damage to private property, community infrastructure and personal injuries. Compensation was provided based on the impact of the pipeline

For the BTC pipeline, IFC applied a number of environmental and social safeguards[45]. These included

- A detailed resettlement and compensation action plan, that went beyond national requirements.
- A en environmental and cultural offset investment programme
- Forcing regional review of broader socioeconomic considerations
- Improving the transparency of the development, by ensuring full publication of key documents.
- Verification of all viable pipeline corridor alternatives had been compared and that pipeline route had been optimised for minimum impact.

In terms of the IFC Performance Standards, Standard No. 3 on Pollution Prevention and Abatement and the Guidance Note carries the most significance for CCS. Under Article 10 of Performance Standard 3, project promoters and developers are required to:

> "promote the reduction of project-related greenhouse gas emissions in a manner appropriate to the nature of the nature and scale of project operations and impacts" and "...evaluate technically and financially feasible and cost-effective options to reduce or offset project-related GHG emissions during design and operation of the project"

The Guidance Note suggests that "carbon capture and storage technologies" are a potential reduction and control option for large point source GHG emissions (> 100,000 tonnes CO2 per year). It further suggests that "carbon finance may create additional funding sources for pursuing these reduction and control options". These requirement suggests that the IFC Guidelines should not hinder the development of CCS networks, but rather promote their consideration in the design of projects involving significant CO2 emissions.

7.3.2 Equator Principles

Project financing will be an important model for CO_2 pipeline infrastructure. Project financing is differentiated as a method of funding where the revenues generated by the project provide both repayment and security. A number of countries and organisations have recognised that project financiers may encounter social and environmental issues that are complex and challenging. The Equator Principles are a financial industry benchmark for determining, assessing and managing social & environmental risk in project financing (www.equator-principles.com).

A number of international leading private banks involved with project finance have adopted the Equator Principles. The key element of the Equator Principles in terms of CO_2 pipeline developments is included under Principle 3 – Applicable Social and Environmental Standards (see below). Under this standard, Equator Principle signatory lenders for projects involving greater that \$10 million capital costs are bound by the same terms as the IFC Guidelines with respect to project development (as described in the previous section). Full details of each principle are described below.

[45] http://www.ifc.org/ifcext/btc.nsf/Content/Environmentaland_SocialIssues

Table 7 Equator Principles

Principle	Description
1. Review and Categorise	Category A – significant impacts Category B – limited impacts Category C – minimal impacts
2. Social and Environmental Assessment	Category A and B projects must conduct a Social and Environmental Assessment. This is wide ranging and covers baseline social and environmental conditions, alternative options, requirements under host laws and international treaties, human rights, health, safety and security, cultural property and heritage, biodiversity, renewable natural resources, dangerous substances, major hazards, labour, fire, socio-economic impacts, land acquisition and resettlement, affected communities, indigenous peoples, cumulative impacts from multiple projects, consultation, efficient production, delivery and use of energy, pollution prevention and waste minimisation, pollution controls and solid and chemical waste management. The assessment should propose mitigation and management features.
3. Social and Environmental Standards	Projects in non-OECD and low income OECD countries need to comply with the IFC Performance Standards, EHS Guidelines. Prjoects in high income OECD countries need only comply with local/national laws. IFC performance standards exist for social and environmental assessment and management systems, labour and working conditions, pollution prevention and abatement, community health, safety and security, land acquisition and involuntary resettlement, biodiversity conservation and sustainable natural resource management, indigenous peoples, and cultural heritage. www.ifc.org/enviro
4. Action plan and Management system	Category A and B Projects in non-OECD and low income OECD countries describe and prioritise actions needed to implement mitigation, correction and monitoring to manage impacts and risks.
5. Consultation and Disclosure	Category A and B projects in non-OECD and low income OECD countries must consult with affected communities, and prove that projects have adequately incorporated communities' concerns. Consultation should be free, prior and informed.
6. Grievance Mechanism	A grievance system to be established to allow the borrower to receive and facilitate resolution of concerns promptly, transparently and in a culturally appropriate manner.
7. Independent Review	An independent expert (i.e. not associated with the borrower) must review the assessment, action plan and consultation process and ensure these comply with Equator Principles.
8. Covenants	The borrower will covenant in financing documentation to comply with all relevant host country social and environmental laws, regulations and permits, to comply with the action plan during the construction and operation of the project, to provide periodic reports at least annually demonstrating compliance, to decommission in accordance with an agreed decommissioning plan.
9. Independent monitoring and reporting	An independent environmental and/or social expert should monitor and verify compliance over the life of the loan.
10. EPFI Reporting	Each EPFI should report at least annually on implementation of the Equator Principles.

By adopting these Equator Principle Financial Institutions, negative impacts on project-affected ecosystems and communities are avoided, reduced, mitigated and/or compensated for appropriately. EPFIs will not provide loans to projects valued over US$10 million, where the borrower will not or is unable to comply with the social and environmental policies and procedures that implement the Equator Principles. Importantly, these standards could override and exceed national level permitting requirements in many jurisdictions. A list of signatories to the Equator Principles is provided below.

In recognition that major infrastructure projects frequently have local social, environmental or health impacts, a number of finance institutions have adopted principles that attempt to minimise adverse impacts and/or promote principles of sustainable development. These principles are implemented through guidelines describing the types of best practice and assessment that should be carried out prior to the financing of such projects, such as environmental, health and social impact assessment. As an example, guidelines for lending by the World Bank and the International Finance Corporation – and as adopted by signatories to the Equator Principles – cover a range of relevant aspects such as the nature of public consultation processes, treatment of displaced peoples, consideration of alternative options, and the treatment of wastes and hazardous materials. Similar principles have been adopted by most multi-lateral lending agencies.

It is expected that similar lenders for large natural gas pipeline infrastructure projects will be involved in financing CO_2 pipeline infrastructure projects. Consequently it is reasonable to assume that these lenders will continue to seek to enforce best- and sustainable development practices on the developers of CO_2 pipeline infrastructure. Whilst this is to be welcomed, it may increase the costs and time required for CO_2 pipelines to be developed. In order to balance such requirements, the urgent imperative for CCS to abate CO_2 emissions should also be considered to ensure balanced evaluation of environmental protection needs.

7.3.3 Carbon finance - Emissions Trading schemes

CCS could potentially be funded through emerging emissions trading scheme systems such as the EU's emission trading scheme, or the Kyoto Protocol's clean development mechanism of joint implementation mechanisms. In addition, international emissions trading under the Kyoto Protocol could potentially create a situation where governments holding surplus assigned amount units as a result of CCS could sell these to other ratifying governments for direct revenue. The implications for each of these is considered further below:

7.3.3.1 Cap-and-trade schemes

The Kyoto Protocol sets out the structure of an international emission trading framework that essentially operates as a cap-and-trade programme for governments. Under the Protocol, ratifying countries are bound by quantified emission limitation and reduction obligations for the compliance period 2008-2012 – the total amount of emissions countries are allowed to make is called its called assigned amount. Governments are required to monitor national emissions in accordance with IPCC guidelines, and report their emission to the UNFCCC. If emissions over the compliance period exceed the countries assigned amounts, they may either purchase assigned amounts from other Parties, or purchase "offsets" generated through the Kyoto project-based mechanisms in order to meet their compliance obligations. In terms of CCS under this scheme, it is presently not formally recognised within the programme due to the lack of consideration within either the 1996 IPCC GLs or the 2000 GPGs (see Section 8.1.6). However, if the 2006 GLs become approved by the COP, emission reductions achieved through CCS will be able to be deducted from national greenhouse gas inventories[46].

[46] Notwithstanding this current gap, Norway has reported injected CO_2 at Sleipner as a non-emission in its national greenhouse gas inventory for a number of years.

In order to pass on this burden to the private sector (and emitters) in jurisdictions covered by the Kyoto Protocol, some regions have sought to introduce regulatory cap-and-trade schemes. Under these schemes qualifying participants – generally large point source emitters of greenhouse gases - are either allocated a set number of emission rights (or allowances) for a given period, or are required to purchase emissions rights, usually through an auction of a finite pool of total allowances. The EU emissions trading scheme is the largest such example of a regulatory enforced cap-and-trade scheme for greenhouse gases. It is now in its second phase, running over the period 2008-2012, although this period does not include any specific provisions for CCS. The revised EU Emission Trading Directive (2009/29/EC), covering phase III of the scheme (2013-2020), does include specific provisions for CCS operations. The Directive enforces the following in relation to CCS:

- *CO_2 capture*: qualifying installations employing CO_2 capture technologies are absolved of the requirement to surrender allowances for the mass of CO_2 that is captured and transferred for permanent storage in a storage site covered by the scope of the CCS Directive

- *CO_2 transport:* pipelines for the purpose of CO_2 storage are included within the scope of the Directive i.e. they become qualifying installations. Such installations receive zero allocation of free allowances. This means that operators will be required to apply to the competent authority for a Greenhouse Gas permit, outlining their emission monitoring programme for the pipeline. They must report annually on emissions from the pipeline, and surrender allowances to the competent authority for any emissions that have occurred. These will need to be purchased on the carbon market.

- *CO_2 storage*: storage sites will be bound by the same considerations as pipelines, namely they must apply for a greenhouse gas permit, monitor, report and surrender allowances equal to monitored emissions.

In terms of CO_2 pipelines, the scheme will impose regulatory (permit application), technical and cost (in terms of monitoring) requirements, as well as potential financial penalties (in the event of leaks) on pipeline operators, although it is unlikely to impose direct regulatory impediments to CO_2 pipeline developments. It will also require a value chain to be built that is able to distribute the benefit of the avoided cost gained by the CO_2 capture installation operator to other parts of the CCS chain. The structure could pose complications where pipelines cross international borders within the EU. However, the nature of joint and several regulatory responsibilities between the two or more competent authorities in the relevant jurisdictions should in principle be governed by the overarching greenhouse gas accounting principles proposed by the IPCC 2006 GLs (see Section 8.1.6).

Similar regulatory configurations can be expected in other jurisdictions looking to develop cap-and-trade style emission trading schemes. For example, a similar structure seems to be the preferred option of the Australian government for its proposed Carbon Pollution Reduction Scheme.

7.3.3.2 Project-based mechanisms

Project-based mechanisms can provide a means by which emission reduction projects can generate credits in jurisdictions without emissions caps and/or regionally enforced cap-and-trade programme. Unlike cap-and-trade schemes, the structure of such mechanisms is predicated on the establishment of an emissions “baseline” that represents what emission would be in the absence of the project. Any emissions from the project are subtracted from the baseline, and the net reduction equals the emission reductions which can be monetised as “credits”. A baseline is not needed in cap-and-trade based schemes as the emissions amounts are set by the cap in force under the scheme. Credits generated in the project-based mechanisms can be purchased by entities subject to a cap as a contribution towards compliance with that cap.

The Kyoto Protocol introduced two international regulated forms of project-based emission trading mechanisms: joint implementation (JI; between Annex I Parties to the Convention that have ratified the Protocol) and the clean development mechanism (CDM: between Annex I and non-Annex I Parties to the Convention that have ratified the Protocol). Presently CCS is not eligible within the CDM, and has not been tested under JI. The issue of eligibility within the CDM has and continues to be part of a long and protracted debate amongst governments within the framework of the UNFCCC and Kyoto Protocol negotiations, dating back to late 2005[47].

In the case of a vertically integrated CCS project with a single source, pipeline and sink, it may in principle be possible for the whole system to receive CDM credits related to the difference between the emission from the project and the projects baseline. This is particularly simplified if there is single entity owner for all elements of the CCS chain.

However, two key underpinning principles of project-based mechanisms create challenges for including more complex integrated CCS networks i.e. those involving multiple sinks and sources, namely: crediting periods and project boundaries. Crediting periods essentially act to create temporal boundaries for a particular CDM project activity. Project boundaries serve to create geographical limits for a project activity. All emission taking place within the geographical and temporal boundary against the baseline can generate credits which can be traded.

Problematically, when considering more complex forms of ownership and integrated networks of sources and sinks, a range of issues emerge. For example, it is unclear whether a new source of CO_2 connecting to an existing CCS CDM project activity could be included within that specific project activity, or whether it would constitute a new project activity. This is further complicated where it joins sometime after the start of the crediting period, and would continue beyond the end of the crediting period of the original CDM project activity. Multiple ownership and issues around several liabilities for any leaks of CO_2 create additional complications. Additional challenges would occur if (a) one country involved in CCS infrastructure was not an eligible country for receipt of CDM credits, whereas other countries were eligible; (b) enhanced hydrocarbon recovery was a material component of the CCS project; (c) legislation mandated the use of CCS (thereby making it part of the baseline).

For these reasons, project-based mechanisms will face challenges in being applied to complex integrated CCS systems, and indeed could act as an impediment to the development of CCS networks where it is the sole driver for development. Therefore, over the medium to longer term, wholesale deployment for integrated CCS networks will likely require some form of alternative incentive mechanism in countries without cap-and-trade schemes. Notwithstanding these challenges, the CDM could provide an important incentive to get early opportunity CCS projects off the ground in the initial stages of CCS development (for example in natural gas processing operations). These issues are all subject to ongoing debate within the auspices of the UNFCCC and developments in the longer-term and after the end of the first Kyoto Commitment Period. As a consequence, significant uncertainty remains over how CCS could be handled within the international climate change policy architecture.

It is also important to note that the Clean Development relies on a project that demonstrates CO_2 savings relative to a baseline project option, and therefore funds cannot be used to fund only the development of supporting infrastructure.

7.4 Conclusions and recommendations

Drawing on the lessons from the organisation of pipeline transportation in the oil and gas industries this chapter presents possible forms of economic organisation of the CCS chain

[47] A recent review of the status of the debate can be found in: P. Zakkour, E. King, G. Cook, N. Maruyama, and S. Rana (2008) "Carbon Dioxide Capture and Storage in the Clean Development Mechanism: Assessing Market Effects of Inclusion". IEA Greenhouse Gas Programme, TS 2008/13.

that will facilitate efficient investment in, and efficient financing and economic regulation of, CO2 pipelines.

The overview of the development of pipelines and markets in pipelines in the oil and gas industries generates one important observation and two broad, but generally applicable, conclusions.

The observation is that the extent and intensity of pipeline regulation across jurisdictions and over time outlined in final row in the table. Economic regulation is less intrusive and intensive when and where market participants are permitted and encouraged to form coalitions and collaborate (EU crude oil and petroleum product pipelines and upstream gas pipelines) or the regulatory authority promotes and facilitates the emergence of a competitive market in pipeline investment (downstream gas in North America).

The first conclusion is that, in the context of dedicated, frequently large-scale and long-term investments, oil and gas market participants will seek solid assurances of full investment recovery (including an appropriate risk-related rate of return). And this seems to be the case particularly for pipeline investments. This tends to lead to the formation of coalitions and joint ventures in the oil industry and to vertical integration in the gas industry.

The second conclusion is that the economic organization of the oil and gas supply chains is determined by the existence of, and the ability to capture, surplus value in the supply chains. All oil and gas market participants deny the existence of surplus value, the motivating impact of its existence and the desire to capture a share, but its importance is revealed in the forms of economic organization that have emerged. In the oil industry, when more than one party is involved, investment in, and the operation of, pipelines is designed to ensure the recovery of the investment, the minimisation of cost and the removal of any ability to capture surplus value in this part of the chain. In the gas industry there is a tendency to opt for vertical integration both upstream and downstream of the point where pipeline supply contracts are agreed. This is designed to ensure recovery of investment and to prevent leakage of the share of surplus value negotiated.

The competitive markets in both gas and pipelines that have emerged in North America provide assurance of investment recovery and compete away any surplus value that emerges. The EU is still a long way from replicating this and there are justifiable doubts as to whether or not it is either feasible or desirable. Via merger and acquisitions many of the previous dominant incumbents in the larger national electricity and gas markets are forming pan-European vertically integrated operations along the gas and electricity supply chains. The Directorate-General for Competition (DG COMP) of the European Commission is progressively enforcing competition law to compel these entities to divest their networks to allow transparent and non-discriminatory access. Not surprisingly the efforts by the Directorate-General for Energy and Transport (DG TREN) to legislate for this unbundling have been met with considerable industry and national government opposition. The resulting legislation, inevitably a compromise, is unlikely to foster the emergence of competitive investment in gas pipelines. As a result, regulation is required to be continuously more intensive and intrusive.

Three options emerge from this assessment:

> ***Collaboration***: emitters and sink-holders enter into a JV to capture, transport and store CO_2 and to share the value of the emission allowances between them;
>
> ***Negotiation***: the emitters take responsibility for capturing and transporting CO_2 to a hub; sink-holders take responsibility for transporting CO_2 from this hub, injecting and storing it; the emitters and sink-holders negotiate the share of emission allowance value to which each party is entitled. This option has two possible further variants a. sink-holders taking responsibility for transmission from the point of capture, and emitters taking responsibility for transmission to the gathering point for injection. These generate three possible locations for the negotiations between the emitters and the sink-holders;

Unbundled, competitive transmission investment: sink-holders and emitters negotiate a price that the sink-holder will pay to the emitter for delivering specific volumes of CO_2 at a specific location (could be the entry point to the pipeline, a physical hub where a number of pipelines interconnect, or the sink-holder's gathering point for injection) and both parties engage pipeline companies to hold "open seasons" to provide the transmission capacity. This option has the potential for the trading of CO_2 abated at a physical hub and with a basis differential between the traded price and the EUA price.

It is important to note that a completely new pipeline business (which is what CO_2 transport in response to climate change price signals will be) has never been initiated using the competitive investment model. It has only emerged through the reform of an existing industry. This does not mean it is impossible - and the benefits of doing so are clear, but, in the context of the huge uncertainties surrounding CCS, it is unlikely to be the first choice - particularly at the demonstration and early development stages of CCS.

This suggests that the first two options will dominate the thinking of industry participants and, of these, it may be that the first, "collaboration", option will be preferred. Collaboration will provide the heft and cohesion to negotiate with governments to extract concessions and subsidies. However, in terms of protecting the public interest, reducing localised monopoly power, ensuring efficient investment and operation and encouraging efficient network development this option performs poorly.

The second option should perform better as it may curtail the power of the emitters and sink-holders in negotiations with governments regarding the nature and extent of public support required. It also provides the potential to extract an unbundled pipeline business as the industry approaches independent commerciality - leading to the competitive provision of investment (Option 3). It may also be possible to extract an unbundled pipeline business from Option 1, but it is likely to prove more difficult.

This leads us back to just two principal options each including varying degrees of potential to incorporate an evolution to competitive investment in pipelines.

Given the very early stage of development of the CCS industry it is only possible to make some broad recommendations:

- wherever possible the potential to establish competitive markets in pipeline investment should be investigated and pursued;
- in the event that this potential does not exist, collaboration among and/or negotiation between markets participants in the development of CO2 pipelines should be promoted and fostered ahead of vertical integration; and
- where vertical integration emerges as the most effective means to develop a CCS project, the potential to effect a transition to the competitive provision of pipeline investment should be under continuous consideration.

These arrangements focus on developed economies where, with an appropriate form of economic organisation and regulation, it is generally possible to secure financing for economically viable pipeline projects. Although it is contended that the economic organisational options considered have universal relevance, beyond the developed economies and in a global context more wide-ranging and complex challenges arise. Two, in particular, are:

- Financing practices that imposes stringent environmental, health and safety guidelines or permitting conditions, beyond those required by national governments. Two important examples are (i) the World Bank/International Finance Corporation (IFC)-funded projects and (ii) projects funded by signatories to The Equator Principles for determining, assessing and managing social and environmental risk in project financing.

- Accounting practices, for example in cap and trade schemes such as the ETS or project based mechanisms such as the Clean Development Mechanism, frequently impose definite boundaries on projects or participating countries. Projects which involve some countries that are eligible for funding and some that are not eligible will face complex accounting challenges.

In this area the following recommendations are relevant.

- Specific guidelines are developed in respect of potential funding for CCS infrastructure from World Bank/IFC and Equator Principle signatories.
- The potential to amend accounting practices within cap-and-trade schemes (such as the EU ETS) and project-based mechanisms (such as the CDM) to promote international CCS infrastructure is investigated.

8 ACKNOWLEDGEMENTS

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9 APPENDIX 1 – A REVIEW OF TECHNICAL, ENGINEERING AND HEALTH AND SAFETY ISSUES FOR CO_2 PIPELINES

This Appendix focusses on technical design and HSE issues. Many of these issues have their origin in the unusual nature of the fluid to be transported, predominantly CO_2 mixed with a variety of other substances.

9.1 Background

The CO_2 transported by CCS infrastructure will have been captured at source using a variety of capture technologies. The exhaust stream from the capture process will contain CO_2 and other components that will depend on the fuel source, the capture technology and the post-capture treatment employed. The composition of the CO_2 stream to be transported will be specified by legislation/regulation (e.g. pipeline codes impose restrictions based on safety requirements) and whether it is to be stored or used for enhanced oil recovery (EOR). However, in the interests of economy it is desirable to carry out as little post capture processing as is consistent with HSE, environmental, pipe material related aspects (i.e. corrosion, embrittlement), storage requirements, operational requirements and requirements to limit the loss of valuable components such as methane or hydrogen. The presence of other components in the stream influences its physical properties and has a knock on effect on matters including hydraulic characteristics, compression and transport efficiency and environmental impact.

The phase diagram for CO_2 alone is shown in Figure 23. This diagram contains two distinct features: the 'triple point' at (5.2 bar,-56°C), where the CO_2 can exist at all three phases (solid, liquid or gas); and the 'critical point' at (73.76 bar, 30.97°C).

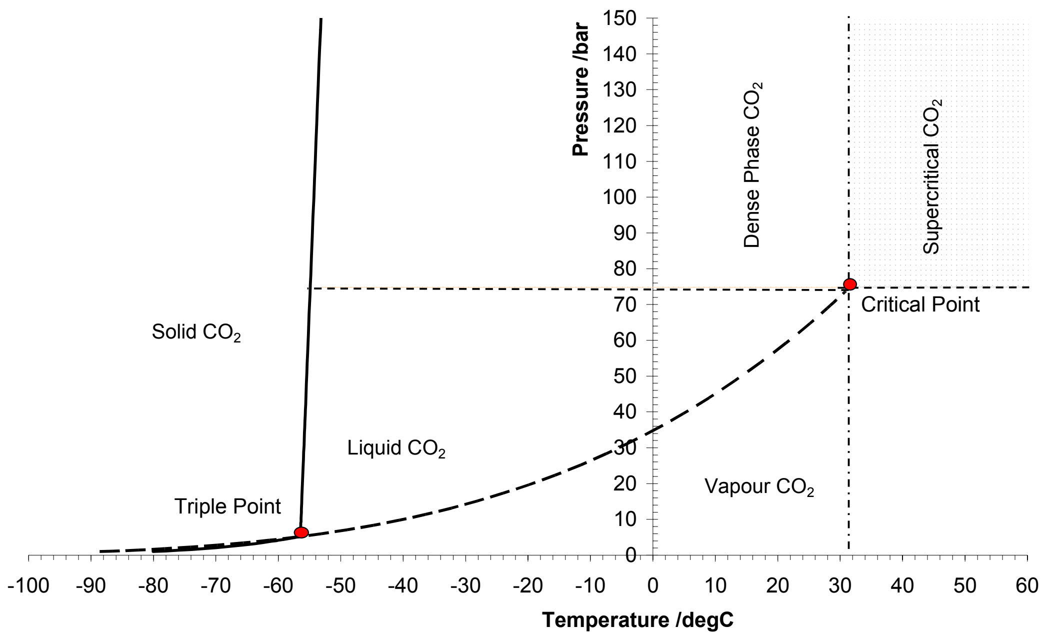

Figure 23 : The phase diagram for pure CO_2 identifies the phase of CO_2 at any given temperature and pressure. For pipeline transportation the transported fluid is kept either on the liquid, or on the vapour, side of the vapour/liquid line running between the triple and critical points, but is not allowed to cross it. This is accomplished if the pipeline system is operated well above the critical pressure of the CO2 stream, including allowing for potential deviations of the real system from the design case.

At pressures and temperatures above the critical point, CO_2 no longer exists in distinct gaseous and liquid phases, but as a supercritical phase[48]. This phase has densities and viscosities which range between those of a liquid and of a gas depending on precise conditions of temperature and pressure. Distinct liquid and gas phases do not exist above the 'critical temperature'. The 'critical pressure' is the vapour pressure at the critical temperature. The supercritical region lies above the critical temperature and pressure, and the 'dense phase region' is located above the critical pressure, but below the critical temperature. In pipelines it is most economic to transport CO_2 as a supercritical fluid or in dense phase where the density is relatively high and the viscosity relatively low. For this reason virtually all existing CO_2 pipelines are high pressure lines, although it is also possible, and may be desirable in certain circumstances, to transport CO_2 as a gas.

The introduction of other components into the CO_2 stream, in the capture process for instance, can have a marked influence on the phase behaviour of the mixture. The phase diagrams for the type of mixtures that might be expected from the three main capture technologies, Oxyfuel, Precombustion and Postcombustion are shown in Figure 24, along with the flow specified for the Canyon Reef Carrier (CRC) Pipeline, an existing pipeline in the USA transporting CO_2 for EOR.

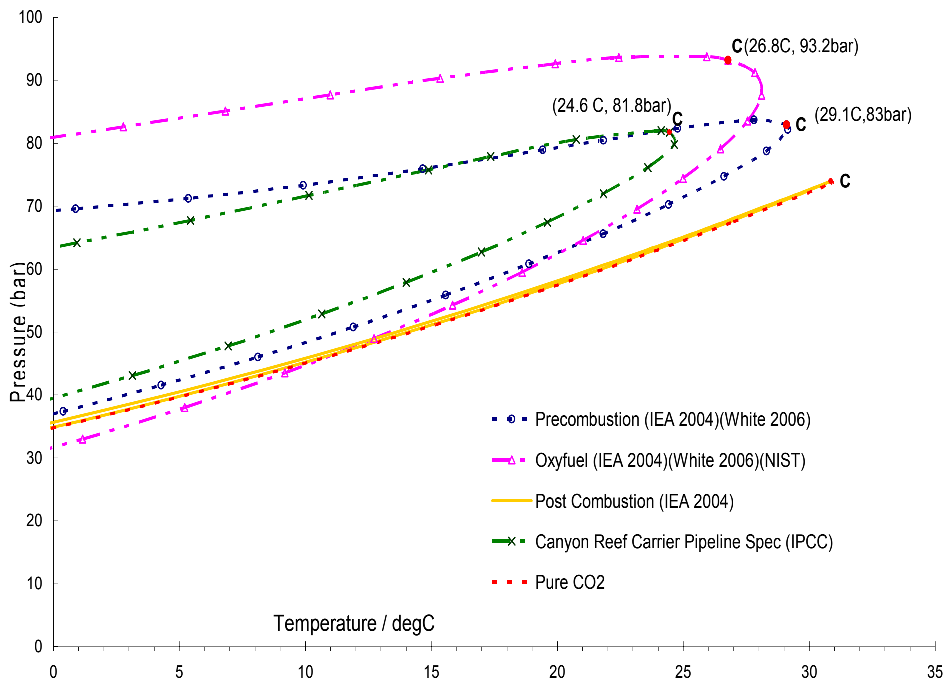

Figure 24 Phase diagram comparison for the three different capture streams and the CRC pipeline specification (Seevam et al., 2008). The vapour/liquid line opens out into a two-phase envelope. The critical point for the different capture streams are labelled 'C' and mark the division for each one between the supercritical and dense phases as shown in Figure 23**.**

The effect of adding other components into the CO_2 stream is, potentially, to change the location of the critical point on the phase diagram and to transform the vapour liquid line (as shown in Figure 1) into an envelope enclosing a two phase gas-liquid region. Two phase flow introduces operational difficulties and can be damaging to pipelines, and so conditions

48 Standardisation of terminology may be useful here – this study encountered multiple definitions and usage of CO_2 phases.

leading to two phase flow are best to be avoided in pipeline design. The extent to which these effects occur is dependent on the types of component and their concentrations present in the CO_2 stream. The phase behaviour of the CO_2 stream strongly influences pipeline hydraulics and, to a greater or lesser extent, many other aspects of pipeline design.

9.2 Pipeline engineering constraints

Pipeline engineering constraints include generic constraints, such as design and HSE regulations, which in many respects are similar to those for transporting oil and gas, and those that apply peculiarly to a CCS infrastructure, stemming largely from the CO_2 stream specification, which has far reaching consequences.[49]

9.2.1 Regulatory framework

Pipeline design is normally constrained by a regulatory framework but in several countries, this does not currently exist for the transport of CO_2. Likely regulatory developments can be inferred from the experience of CO_2 pipeline transport for EOR in the USA, and existing national regulations relating to the transport of oil and gas. It is important to understand, however, that the transport of anthropogenic CO_2 for CCS will be markedly different from that for oil and gas, and significantly different from that for naturally occurring CO_2 for EOR. The differences lie not only in the nature of the fluid, but also in the circumstances and objectives of its transportation. In some countries therefore existing regulations will need modification, and completely new ones may need to be developed.

Transportation of relatively pure CO_2 by pipeline has been practiced in the US for over 30 years and, consequently, provision is made in the ASME pipeline design code (ASME B31.4, 2006) and Federal Regulations (49CFR195, 2008) for the design and operation of supercritical CO_2 pipelines. Supercritical CO_2 pipelines have been classified as hazardous liquid pipelines, which are regulated under Federal Regulations (49CFR195, 2000) but the literature suggests that most operators have designed the pipelines using the ASME B31.8 code for gas pipelines which tend to be more conservative (Kantar, 1984; Decker, 1985; McCollough, 1986). Onshore and offshore pipeline design in the UK is conducted in accordance with PD8010- and the Institute of Gas Engineers recommendations (IGE/TD/1, 2001). These regulations make no provision for the design of supercritical pipelines. The transportation of CO_2 as a gas is included in PD 8010-1.

Pipeline design is governed by 'design factors'. The pipeline design codes dictate the maximum design stress of a pipeline by specification of a 'design factor', defined as the ratio of the hoop stress to the SMYS (Specified Minimum Yield Stress) of the pipe material. The design factor is used to control the level of stress in a pipeline, see equation 4.1. The higher the design factor, the higher the allowable stress in the pipeline. Most pipelines around the world have a maximum design factor of 0.72, although there are some pipelines operating at higher factors. The design factor minimises the risk of pipeline failure and therefore is assigned in relation to the location of the pipeline and the substance being carried. Design factors for a given pipeline are reduced from the maximum according to the proximity to people and the hazardous nature of the transported fluid.

The different codes assign the design factors by different methods. The ASME codes assign a value of 0.72 for liquid hydrocarbons and other liquids, and values in the range 0.8 – 0.4 for

[49] Constraints in capture, compression, drying and injection facilities are outside the scope of this report, but merit separate analysis. As an example, the technologies and supply chains for CO_2 compression may have a material impact on the CO_2 pressures that are economically achievable and therefore could influence overall pipeline specification.

gases. The design factor for gases is determined by the location class, defined by the number of buildings per mile in a quarter mile corridor along the pipe route. PD 8010-1 classifies the type of fluid as one of categories A - E and assigns values to the design factor ranging from 0.72 – 0.3 according to one of three location classes based on the population per hectare for categories C - E. Gas phase CO_2 falls into category C. Liquid phase CO_2 has not yet been classified, however it should be noted that PD 8010-1 states that the routing of pipelines conveying category C to E substances through high population density locations should be avoided. IGE/TD/1 has three location classes: rural (R), densely populated urban (T) and "areas intermediate in character between R and T",(S).These definitions are based on the population occupying a corridor 1.6 km in length and 8 times the building proximity distance (BPD) centred on the pipeline. The design factors again range from 0.8 (R) t0 0.3 according to the location class

The codes also identify other high risk areas, such as road, rail and pipeline crossings, where the design factor could be reduced below those otherwise given by the appropriate class locations, or alternative means of reducing the risk are employed.

9.2.2 CO_2 stream specification

Existing pipelines mostly transport naturally occurring CO_2 for the purpose of EOR. Naturally occurring CO_2 is relatively pure, and for EOR all components of the CO_2 stream that raise the minimum miscibility pressure of CO_2 with crude oil are removed because they raise the injection pressure. For that reason the phase behaviour of a CO_2 stream for EOR is similar to that of CO_2 alone. However, there is an economic incentive to remove such components for EOR, owing to the revenue stream from the produced oil, which would not be present for storage applications.

With one exception[50], no existing pipelines transport CO_2 from power plant capture. Projected specifications for a CO_2 stream composition for power plant CCS have been considered from two different perspectives; the first takes the capture process as the starting point and analyses the components that could be present, for example, (IPCC, 2005; ENCAP (Anheden, 2005); Oosterkamp and Ramsen, 2008). The second starts from the pipeline and defines the levels of impurities that could be safely transported from both a health, environmental and technical point of view for example, Dynamis (Visser and Hendricks, 2007); Ecofys (Hendriks *et al*., 2007). The specification proposed by the IPCC is given in Table 1, and the Dynamis and Ecofys specifications in Table 2. Note that, apart from a study by Seiersten *et al*. (2005), little work has been done on identifying the maximum concentrations of water and other contaminants for alternative grades of steel (e.g. stainless steel), possibly because the additional costs involved for long subsea pipelines make it a more attractive option to process the CO_2 prior to admission to the system. [51]

[50] A 1000 tons/day (42 tons/hour) CO_2 recovery plant at Lubbock, Texas (USA) used the Fluor Daniel econamine process to remove CO_2 from the flue gas of a natural gas power plant. The facility was designed to pipe CO_2 for EOR at the nearby Garza field. The plant was shut down following the collapse in the crude oil price in 1986.

[51] Stainless steel pipelines are extremely expensive compared to carbon steel grades, therefore such solution might only be a reasonable solution for relatively (very) short pipeline systems. Potentially stainless steel cladded pipelines might allow less expensive solutions compared to 'pure' stainless steel pipelines.

Table 8 Predicted composition of CO_2 from power plant capture (IPCC, 2005)

Coal Fired Power Plants	Component	Coal Fired % Volume	Gas Fired % Volume
Post-Combustion Capture	SO_2	<0.01	<0.01
	NO	<0.01	<0.01
	$N_2/Ar/O_2$	0.01	0.01
Pre-Combustion Capture (IGCC)	H_2S	0.01-0.6	<0.01
	H_2	0.8-2.0	1
	CO	0.03-0.4	0.04
	CH_4	0.01	2
	$N_2/Ar/O_2$	0.03-0.6	1.3
Oxyfuel	SO_2	0.5	<0.01
	NO	0.01	<0.01
	$N_2/Ar/O_2$	3.7	4.1

The post-combustion process needs to have a relatively low sulphur content because SO_2 poisons the solvent in the absorption process and so it is removed from the feed gas prior to the scrubbing unit to avoid excessive solvent loss through purging. The IPCC report suggests that for oxyfuel and pre-combustion capture, leaving sulphur compounds in the CO_2 product stream could be economically beneficial as it will reduce the cost of capture. For pre-combustion the sulphur is in the form of H_2S, itself toxic[52]. In some cases, preferential removal of SO_2 may occur during CO_2 compression and drying stages. In any case, the priority will always be to obtain consents from regulators.

The Dynamis project[53] is an integrated European project investigating the production of hydrogen and electricity from fossil fuels with CO_2 capture and permanent storage. Their specification is based on the ENCAP[54] specification for pre and post-combustion capture but it has been modified to take account of safety and toxicity limits, in the event of a release from the pipeline; infrastructure durability, in terms of the need to avoid free water formation, hydrate formation and corrosion; and transport efficiency (Visser and Hendricks, 2007).

In this study, the allowable levels of H_2S, CO, SO_x and NO_x have been determined by using the Short Term Exposure Limits for these compounds to set a maximum concentration in the CO_2 stream, taking into account air dilution effects during a pipeline release. The impact of the components on the pipeline hydraulics has not been taken into account.

52 H_2S can be beneficial for EOR or as an odorant, but poses a danger in the event of a pipe burst, and therefore H_2S levels should be controlled.

53 The forthcoming revision to Dynamis' pipeline specifications is expected to reduce water concentration considerably below the value of 500 ppm, and oxygen levels below 10 ppm. At the lower oxygen concentration the potential for interaction of oxygen with hydrogen is eliminated. (*A. Brown, personal communication*)

54 EU Framework 6 project entitled European Enhanced Capture of CO_2 (ENCAP).

Table 9 Pipeline specifications[55] proposed by the Dynamis and Ecofys project (de Visser and Hendricks (2007), de Visser *et al* (2008) and Hendriks *et al* (2007))

<table>
<tr><th rowspan="2"></th><th colspan="2">DYNAMIS</th><th rowspan="2">ECOFYS</th></tr>
<tr><th>Storage</th><th>EOR</th></tr>
<tr><td>CO_2</td><td colspan="2">>95.5%</td><td>>95%</td></tr>
<tr><td>H_2O</td><td colspan="2">500 ppm</td><td><500 ppm</td></tr>
<tr><td>SOx</td><td colspan="2">100 ppm</td><td>Not critical</td></tr>
<tr><td>NOx</td><td colspan="2">100 ppm</td><td>Not critical</td></tr>
<tr><td>H_2S</td><td colspan="2">200 ppm</td><td><200 ppm</td></tr>
<tr><td>CO</td><td colspan="2">2000 ppm</td><td><2000 ppm</td></tr>
<tr><td>H_2</td><td rowspan="5"><4 vol%</td><td rowspan="3"><4 vol%</td><td rowspan="5"><4 vol%</td></tr>
<tr><td>Ar</td></tr>
<tr><td>N_2</td></tr>
<tr><td>O_2</td><td>100-1000 ppm</td></tr>
<tr><td>CH_4</td><td><2 vol%</td></tr>
</table>

A Dutch study on CO_2 transport, performed by Ecofys, took a similar approach to the Dynamis project, except that the case study was based on potential impurities from coal fired power plants (Hendriks *et al*., 2007).

To date, there is no generally accepted specification for the CO_2 stream for CCS. One possibility is that the composition of the CO_2 stream will depend on the relevant capture technologies and where it is stored. Thus different countries, regions or projects could adopt different specifications. An alternative approach is for a dedicated transport (and possibly storage) company to dictate entry specifications, along with accepting responsibility for transport and storage. Where these entry specifications are coordinated this allows for a common entry specification and ease of expansion of pipeline infrastructure. A lesson from low carbon technology deployment generally is that standardisation of entry conditions can facilitate the development of best practice guidelines for various aspects of pipeline design, siting, management,and eventual decommissioning. This approach can help to minimise the need for stakeholders to tailor their approach for each pipeline – which would increase costs and risks.

9.2.3 The presence of water

The one component about which there is a consensus view, and the one that potentially can have the largest effect on the pipeline, is that water will have to be removed. Free water is water that is not dissolved in the CO_2 stream. The presence of free water (as opposed to dissolved water) in the CO_2 stream may cause corrosion of the pipeline steels and/or lead to hydrate formation in the pipeline. All of the operational CO_2 transmission pipelines are manufactured from plain carbon steel which is essentially non-corrosive in pure CO_2. Trace water dissolved in the CO_2 stream is not a significant problem. However, in the presence of *free* water, highly corrosive carbonic acid is formed and it has been reported that carbon steel can corrode at rates of more than 10mm/year in wet pure CO_2 (Seiersten and Kongshaug,

[55] de Visser, E. & Hendriks, C. (2007) "Towards Hydrogen and Electricity Production with Carbon Capture and Storage- DYNAMIS Quality Recommendation," DYNAMIS, Project No.: 019672 ; de Visser, E., Hendriks, C., Barrio, M., Mølnvik, M.J., de Koeijer, G., Liljemark, S. & Le Gallo, Y. (2008) "Dynamis CO_2 Quality Recommendation", Int. J. Greenhouse Gas Control (2008); Hendriks, C., Hagedoorn, S. & Warmenhoven, H. (2007)"Transportation of Carbon Dioxide and Organisational Issues of CCS in the Netherlands", Report prepared by Ecofys for EnergieNed, the Ministry of Economic Affairs and the Ministry of Housing, Spatial Planning and the Environment, March 2007.

2005). At a constant temperature, the solubility of water in gaseous CO_2 drops with increasing pressure until it reaches a minimum as it approaches the boundary of the CO_2 liquid/vapour envelope, as shown below. As the solubility of the water in CO_2 falls, it is more likely to form the free water phase. Further increases in pressure are accompanied by a step change increase in solubility across the envelope, and then a more gradual rise in the liquid phase. The specification of an acceptable level of water in the pipeline is dependent on the solubility of water in the fluid at the operating temperature and pressure – the amount of water must be significantly less than the maximum that can be dissolved in the CO_2. The solubility limit for water in pure CO_2 at supercritical or dense phase pipeline operating conditions is up to 160lb/MMscf (0.0026kg/m^3) and it has been determined that corrosion of carbon steel will not occur if the water content is below 60% saturation (0.0015kg/m^3) (Najera, 1986). There is no general consensus for the specification of an acceptable level of water for gaseous phase transport of CO_2 as such pipelines are comparatively rare and insufficient experience has been accumulated. There may not be sufficient evidence to set a definitive acceptable limit for H_2O in CO_2. A conservative limit could be taken as 60% of the minimum solubility achieved by pure CO_2 at the design temperature, e.g. 200 ppm at 4°C. Others have considered 75% might be an acceptable safety margin[56].

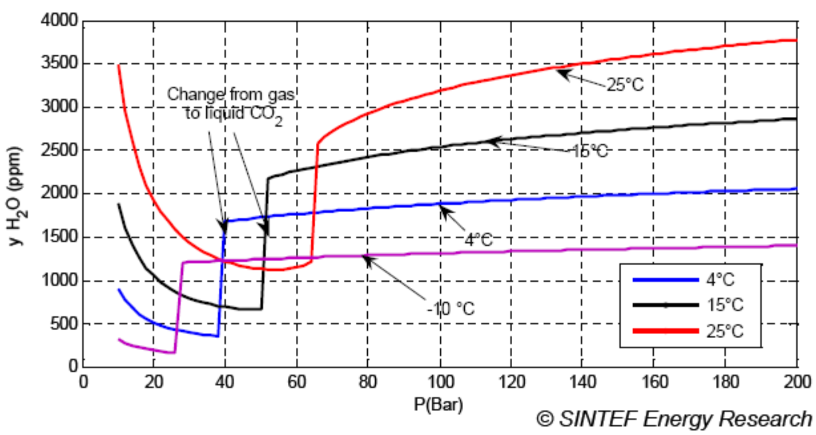

Figure 25 Solubility of water in pure CO2 as a function of pressure and temperature (Austegard et al, 2006 as cited by Visser and Hendriks (2007))

In order for hydrates to form in a CO_2 pipeline there must be the required combination of pressure and temperature and a sufficient amount of free water present. Under CO_2 pipeline operating pressures, it would be possible for hydrates to form at around 10-11°C (Fradet *et al* (2007), Wallace (1985)). The issue with hydrate formation in pipelines is that hydrates are solid compounds with similar properties to ice; consequently they can block the pipeline and plug or foul other equipment such as heat exchangers.

Both the Dynamis and Ecofys projects recommended a water content of 500ppm to ensure that no free water is present in the pipeline. The Dynamis project did conclude, however, that the 500ppm limit should be reviewed for offshore pipelines which could be operating at temperatures around 4°C. At this temperature, the solubility of water is below 500ppm for pressures below 40bar. Under certain conditions therefore there could be a risk of corrosion and hydrate formation in the pipeline. Although the Dynamis report considered the cross effects of H_2S and CH_4 on water solubility in CO_2, the effects of other impurities in the CO_2 stream (*e.g.* O_2) had not been investigated. A conservative limit for water content might therefore be 200 ppm, i.e. 60% of the minimum solubility at 4 ºC. Note that an extension of

[56] Effect of Common Impurities on the Phase Behaviour of Carbon Dioxide Rich Systems: Minimizing the Risk of Hydrate Formation and Two-Phase Flow", Chapoy, Burgass and Tohidi, Hydrafact/Heriot-Watt University, Austell and Eickhoff, Progressive Energy, presented at the Oil and Gas Conference and Exhibition, Aberdeen, 8-11th September 2009.

the Dynamis study is presently considering these issues – and it is expected this study will recommend a water content of 250 ppm[57].

The presence of other components in the CO_2 stream can both increase and decrease the saturation levels and therefore the drying requirements. There is only a limited amount of data available and more laboratory experiments are required to determine the solubility of water in CO_2 containing the types of impurities to be expected from power plant capture over a range of operating temperatures and pressures. Until this data becomes available the specification of water content in the CO_2 stream for both supercritical and gas phase pipelines must be conservative.

The study identifies a paucity of detailed cost-benefit analysis in the public domain that correlates the technologies and costs for drying CO_2 streams captured from different sources against savings in costs for compression, transport and storage infrastructure and recommends this gap is filled.

9.2.4 Pipeline specification

Pipelines for transporting CO_2 are constructed from carbon steel similar to that used for oil and gas pipelines. Usually API 5L Grades X65 or X70 grade pipeline steel is adopted because of the high operating pressures associated with CO_2 pipelines (Seiersten, 2004). Low pressure polyethylene pipelines (up to 7 bar) could be used for collecting gaseous CO_2 on the peripheries of networks. A complete list of available pipe types together with their dimensions and material properties is presented in API 5L (2007). The CO_2 transported in these pipelines has to be sufficiently dry to avoid corrosion. In locations where CO_2 cannot be dried, or in processing piping equipment, stainless steel is usually used (Decker, 1985; Recht, 1987). Stainless steel is more expensive than carbon steel, so it is not the preferred pipe material.

9.2.4.1 Maximum operating pressures

The maximum operating pressures for the pipeline are determined based on regulations, existing CO_2 pipeline practices, and pipeline design codes. Current CO_2 pipelines operate from 86 bar to about 200bar (Farris 1986, Seevam 2008) with ambient temperatures ranging from 4°C to 38°C (McCullough 1986, Mohitpour 2006). The pipeline pressures proposed based on economic analysis for dense phase CO_2 transport in the UK range from 110 bar (Gibbins and Chalmers, 2006) to 150 bar (Davidson, 2004 ; Marsh 2003)[58]. A study looking at CO_2 transportation in the Yorkshire and Humber region (Yorkshire Forward 2008) has proposed a 125 bar CO_2 pipeline network. The only offshore CO_2 pipeline in Europe is the Snøhvit pipeline. Its Maximum Allowable Operating Pressure (MAOP) is 170 bar.

9.2.4.2 Crack arresters

Crack propagation is a potential problem in pipelines conveying gas or liquids with high vapour pressures. Fractures can propagate in either the fully brittle or fully ductile modes for long distances, and in theory, could propagate almost indefinitely. In the literature on CO_2 pipelines, many authors have indicated that ductile fracture propagation may be an issue (King, 1982a&b; Decker *et al*, 1985; Maxey, 1986; Marsili *et al*, 1990) and indeed, the requirement to consider fracture propagation in CO_2 pipelines is included in the federal regulations in the USA (49CFR195, 2008).

Models have been developed for determining the toughness requirements for pipe material, which ensure fracture arrest. It has been shown that the arrest pressure can be raised by increasing the wall thickness, increasing the toughness, decreasing the pipe diameter or

[57] A. Brown, personal communication.
[58] Some in industry are proposing limits of 100 bar onshore and 195 bar offshore (A. Brown, personal communication).

increasing the yield strength (King, 1982b). These might be considered expensive options; however, it could be particularly beneficial for offshore pipelines which tend to be of increased wall thickness and pipe grade compared to onshore pipelines. It is considered that, for natural gas pipelines, the methods for calculating fracture arrest conditions are considered to be conservative when applied to offshore pipelines (Maxey, 1984), because of the beneficial effects of hydrostatic pressure, although there is limited information on this.

If the required fracture arrest toughness cannot be identified or attained then it may be necessary to fit crack arrestors, a possibility that is allowed for in PD 8010-1, particularly for high strength steels when the published predictive models may be unconservative. Crack arrestors are usually installed to ensure that a propagating fracture will stop within three pipe spools and can be clock springs or a thicker wall pipe section. Crack arrestors were installed every 5.8km on average on the CRC pipeline (Marsili, 1990) and every 0.4km on the Central Basin Pipeline (McCollough, 1986). Crack arrestors are not usually used offshore.

9.2.4.3 Block valves

Block valves are essential for isolating sections of the pipeline during maintenance and repair and for reducing the inventory loss during an emergency. The spacing of block valves is determined by the design code and is dependent on the substance being transported and/or location class. The ASME B31.4 liquid code requires a maximum block valve spacing of 12km. In PD 8010-1 no specific distances are stipulated but for category C, category D and category E substances, the spacing should be determined by a safety evaluation. IGE/TD/1 also recommends that the spacing of block valves is determined by taking into account a number of factors including pipeline pressure, population density, blowdown time and topography. Block valves are not usually used offshore, although there will be safety valves at the shoreline and at injection facilities. On the basis of the current differences between the US and UK codes, it is unlikely that the prescriptive block valve spacing approach for CO_2 pipelines will be adopted in the UK.

In addition, CO_2 pipeline operators have taken precautions to decrease the risk of failure in high consequence areas by the use of thicker wall pipe, the fitting of crack arrestors and concrete sleeves, increasing the depth of cover and decreasing the distance between block valves.

Barrie et al note that including too many valves from the compressor to the injection or storage point can also be a problem. Although more legs can be isolated and vented, extra valves produce additional leakage paths at the flange connections and past the stem packing. All pipelines have both operating and emergency pressure-relief systems. With CO_2 pipelines, however, care must be taken to ensure that extreme cooling does not take place during pressure relief as this will be detrimental to the valves.

9.2.5 Pipeline hydraulics

Pipeline design requires consideration of the relationship between the flow of the fluid in the pipeline and the properties of the transported fluid under the given conditions of temperature and pressure. This enables the designer to establish the capacity of the pipeline. The flow equations that are used in the design of oil and gas pipelines are derived from the equation for one dimensional fluid flow in a horizontal pipe, see equation 4.3. There are many variations on the basic flow equation. Simple expressions that can be used for pipe sizing in preliminary calculations have been described by Vandeginste and Piessens (2008).[59] More accurate equations including the effects of temperature and compressibility and have been shown to give good results with CO_2 include the AGA equation (Farris, 1983) and the Beggs

[59] Some equations in this paper agree better than others at hindcasting the diameters of existing CO_2 pipelines. They are not however capable of detailed hydraulic calculations.

and Brill equation (Hein, 1985)[60]. The latter allows prediction in the two-phase region, although it reduces to the single-phase gas flow equation if no liquid is present. In all of these equations frictional effects, which are largely responsible for pressure drops along the pipeline, are calculated from empirical relationships depending on the flow velocity, density and dynamic viscosity, and on the pipe diameter and roughness, eg Moody (1944). A systematic validation exercise of equations of state and flow equations for CO_2, particularly with 'impurities' would be useful.

9.2.5.1 Equations of state

The flow equations are functions of parameters whose properties are governed by the phase behaviour of the fluid which itself has to be modelled by equations of state (EOS). Equations of state are empirical relationships based on the ideal gas laws modified to conform to experimental data. The phase behaviour of CO_2 mixtures is heavily dependent on their composition, which in turn has an important impact on the flow equations. However, there is no consensus in the literature regarding the equation of state that should be used for the design of CO_2 pipelines. Li (2006) has conducted a comparative study of all of these equations of state and concludes that their selection may have a significant impact on the pipeline design, although without more experimental data it is not possible to identify the most accurate one to use. Greater experimental validation would reduce any potential real or perceived barriers to CCS adoption. On the basis of available data, Seevam et al. (2008) have obtained good agreement between experimental data and computed results using the Peng Robinson EOS (Peng and Robinson, 1976) and binary and tertiary CO_2 mixtures.
A number of researchers are working to improve approaches to calculating the pressures and temperature profiles reliably[61] – to date however there is no clearly preferred solution.

9.2.5.2 Multi-phase flow

Two phase flow occurs in the two phase envelopes where the CO_2 exists in both liquid and gas phase. It may be desirable to transport the CO_2 stream in dense liquid phase, which is most economical, or in gas phase but the two phase envelope should be avoided because it is associated with large pressure drops and it may cause damage to the pipeline and associated equipment unless they are specifically designed for multiphase flow.. For this reason it is necessary to know the location of the critical point on the phase diagram and the boundaries of the envelope. Although the exact composition of the CO_2 stream is not known, in the case of post-combustion capture the phase diagram is likely to be very similar to that of pure CO_2 due to the low levels and types of additional components in the stream (Table 2). For the case of precombustion the critical point is likely to move to a higher pressure and lower temperature and a two phase envelope will open up.

Current CO_2 pipelines operate over an internal temperature range of around 4°C to 38°C[62] so to transport the CO_2 stream in dense phase, the pipeline inlet pressure is likely to have to be in excess of 100bar and the pressure drop over the pipeline length to be sufficiently small to avoid the two-phase envelope. Similar constraints apply to transporting the CO_2 stream in gas phase except the inlet pressure has to be sufficiently low to avoid the two-phase envelope.

9.2.5.3 Erosional velocity

As well as constraints on the pipeline design are provided by end conditions and the MAOP, there is a further constraint on the magnitude of the flow velocity in the pipe. The velocity has to be smaller than the erosional velocity, a function of the pipe material and the mixture

[60] The impact of viscosity is much smaller than the impacts of density, Joule-Thomson effect, specific heat capacity, isentropic change of temperature with pressure cased by elevation differences. (Dr. K. D. Kaufmann, ILF Consulting Engineers, Personal Communication)
[61] For example the MATTRAN consortium (http://gow.epsrc.ac.uk/ViewGrant.aspx?GrantRef=EP/G061955/1)
[62] This internal operating temperature range is similar to that of natural gas pipelines.

density of the fluid, to avoid erosion of the pipeline due to high flow rates[63]. The erosional velocity (Mohitpour *et al*, 2003) is determined by 4.4.

9.2.5.4 Boosting

If the CO_2 stream is being transported in dense phase it is important that the pressure is kept sufficiently high to avoid two-phase flow. Pressure drops occur in the pipeline due to frictional effects and gravitational (static head) effects related to the pipeline elevation. The fact that the supercritical or dense phase CO_2 is as dense as most hydrocarbon liquids (600-900kg/m^3) means that the effect of static head on the pressure is significant. This will be important in areas where there are variations in topographic height along the pipeline route. This property of CO_2 can be advantageous if the elevation decrease in a pipeline can counteract any frictional losses. For example, in the Sheep Mountain pipeline, once the CO_2 leaves the production facility at 96bar, it is delivered to the oil fields at a pressure of 137bar with no requirement for intermediate compression. The increase in pressure is achieved purely through elevation changes along the 660km pipeline route. Elevation changes are also being used to prevent offshore compression in the Snøvhit pipeline (Pettersen, 2006). In this pipeline the CO_2 is compressed to 150bar and the 150 km pipeline drops 300 m to the injection site. For systems that rely on changes in elevation to achieve the required pressure changes, it is important that a static analysis is conducted to take account of a shut in (Decker *et al* (1985)), when pipeline pressures could be increased.

9.2.5.5 CO_2 pipeline operations

Pipeline operations by their very nature involve transient flows. The transients occur over different timescales (from seconds to weeks) and can be due to routine start up or maintenance to seasonal variations. The software for computing the pipeline flow of CO_2 streams, especially carrying components introduced by carbon capture, is still under development. It has its origins in computing the flow of oil and gas, and the theoretical and empirical input has to be modified for application to the transport of CO_2 mixtures. Steady state CO_2 codes are in a more mature phase of development than transient codes. For this reason there is little to be found in the literature on start-up, blow down, intermittency, line packing and buffers. This will need to be considered during operational design, although should not constitute a significant threat to CO_2 pipeline adoption. Preliminary work by Seevam (2009) has confirmed the expectation and operational experience that start-up has to be carried out slowly to prevent two-phase flows and that there is scope for line packing in gaseous phase, but not dense phase.[64] Studies on intermittency are ongoing.

One route to minimize the degree of intermittency is for a pipeline system to receive its CO_2 from a number of different sources, such that an outage at one will reduce, rather than halt, the flow along the pipe. EOR operations themselves can place a fluctuating demand on the CO_2 supply, and a possible solution may be to operate an EOR demand in conjunction with a saline aquifer or depleted gas field, such that the flow from the sources can always be received.

9.2.5.6 CO_2 pipeline maintenance and monitoring

[63] With a conservative value of C=100 and an assumed density of 750 kg/m^3 the calculated corrosional velocity becomes more than 14 m/s which is much higher than the economic transportation velocity (approx. 1.5-2 m/s) for dense phase CO_2 transport. (Dr. K. D. Kaufmann, ILF, Personal Communication). However, for some conditions erosional velocity is limiting (M. Downie, Newcastle University, Personal Communication)

[64] Natural gas pipelines are designed to occasionally tolerate "linepack", when an upstream compressor operates even though a valve several kilometres downstream may have been inadvertently closed. It is undesirable to have CO_2 compressors continue to operate when downstream valves are closed, since CO_2 disposal is very challenging. A fully functional pipeline control system for monitoring CO_2 accumulation at strategic points in the pipeline is essential. (Barrie et al (2005))

Operators of both CO_2 and hazardous liquid pipelines generally develop and follow procedures governing normal operation, maintenance and emergencies. Maintenance and normal operations cover aspects such as pipeline monitoring, emergency response, repair and analysis of pipeline accidents. A general requirement is that pipelines must be capable of inspection using in-line inspection (ILI) tools and therefore must have pig traps installed. For CO_2 pipelines, operators have encountered problems using ILI tools including deterioration of their non-metallic components by the CO_2 fluid transported, explosive decompression on removal of the tool from the pipeline, ingress of the product into the data storage module of the tool and the formation of ice-blocks in the pig trap during decompression. Although the non-metallic materials on the inspection tools can be replaced with CO_2 compatible materials, this has not entirely eliminated the problems with inspection. Designs for CO_2 compatible pigs are now available in the USA.

In the USA the integrity of pipelines that are not inspectable by ILI has generally been determined by well established alternative direct assessment techniques in which data from indirect measurements define locations where a pipeline is to be directly examined and the integrity of the pipeline segment assessed. Such well established risk-based direct assessment approaches could be generally adopted for the inspection of onshore sections of CO_2 pipelines. However, serious consideration has still to be given to the inspection of offshore pipelines that cannot be inspected by ILI..

9.2.5.7 CO_2 compressors and pumps

Pumping rather than compression is used to maintain the pressure along CO_2 pipelines as it is more economical, efficient and reliable, and has better operating flexibility (Kinder Morgan 2006). In order for pumps to be used, the CO_2 has to remain in a single phase (i.e. supercritical or dense phase). Generally, compressors are used at the pipeline inlet to compress the CO_2 (DTI and IEA, 2000) although in early phase CCS systems this might be at the power station itself. Typically reciprocating compressors are more cost effective for small volumes and centrifugal compressors for larger volumes although there is a wide range of recommended switching points (Caroll, 2006). The majority of the compressors currently used are reciprocating compressors but, whilst still appropriate for small volumes with potential variation in flow rate, for large constant volumes of CO_2 centrifugal compressors are more appropriate (Wallace, 2008).

It is also worth noting that the compressor power requirements would depend on the type, amount and combination of impurities. This has more significance in the UK when the power for the compressor is drawn directly from the CO_2 capture power plant itself instead of the electricity grid. The plant efficiency would be directly affected by this and is therefore a major concern in terms of the cost of capturing anthropogenic CO_2 (Chalmers et al., 2007; Odeh,et al.,2007). Field experience has shown that the natural gas rules used for sizing compressors and pumps is not directly applicable for CO_2 service. Vessels designed for CO_2 service should be sized 10-20% larger than that used for natural gas due to the high density of CO_2. Temperature control is also very important as the density of CO_2 is very sensitive to temperature and can therefore affect pump and compressor capacity which in turn will affect pipeline throughput (Wallace, 2008; Mohitpour et al., 2008).

9.2.5.8 Network Configuration

The pipeline networks will be subject to all of the constraints on point-to-point pipelines compounded by the interaction of multiple sources and a more complicated operational programme. The most significant constraints will arise as a consequence of local, government and international policies and strategies. If governments provide incentives for CCS to develop according to a national strategy, and if that carries through to a centrally planned CCS pipeline infrastructure, then there will be incentives for regional networks to conform to the national network. A similar argument could apply where pipeline infrastructure spans multiple countries. Whether or not this happens, the networks will develop piecemeal and in phases.

Part of the national strategy should include the scope of the infrastructure in the context of how much CO_2 to collect from what percentage of the sources. Again this will happen in phases, see for example Downie et al. (2007) and Bentham (2006), with CO_2 collected first from demonstration projects and the largest emitters. The choices for network configuration resolve themselves into a ring main or a tree structure. Two further factors to be considered are planning the infrastructure in the early phases so that sources can be connected in during the later phases in the most economic and efficient manner, and using existing infrastructure. It is argued in the IEA GHG study on pipeline infrastructure for Merseyside, and a subsequent study for Yorkshire Forward (2007) document that the tree structure is most appropriate in these locations.

9.2.5.9 Existing infrastructure

There is the possibility of using existing gas pipelines for onshore and offshore transportation of CO_2. Pipeline change of use is covered in the various pipeline codes which demand that it should be ensured that: the pressure required for dense phase/supercritical operation does not exceed the design or location factors along the pipeline; the ROW (right of way) is sufficiently wide in relation to the required BPD; the pipe and valve materials have sufficient toughness to arrest long running fractures; the coating materials and any non-metallic materials are suitable for supercritical CO_2 service. On this basis, re-use of existing infrastructure onshore in the UK is likely to be confined mostly to gas phase transport. Similar arguments may apply to the use of high pressure pipelines elsewhere.

9.2.5.10 CO_2 stream network specification

A network connecting multiple sources with different capture technologies needs to be designed on the basis of hydraulic calculations accounting for an appropriate CO_2 stream composition, temperatures, pressures and velocities. Unless the interaction between impurities from different CO_2 sources becomes significant, the network's trunk line worst case may be better than the capture technology worst case because it will be ameliorated by the contribution of the more favourable technologies.[65] Due allowance will need to be taken of the load variation due to the different capture technologies, which should not make widely varying operational demands on the system.

9.2.6 Route constraints

Pipeline routing is constrained by the geography/geology along the route from sources to sinks, rights of way and the proximity of population centres. Pipeline routing may also be constrained by the ability to locate pumping stations, and social preferences.

[65] If all the CO_2 meets a preset shippers' standard, this observation may not be relevant.

9.2.6.1 Building proximity distances

The different codes provide procedures for calculating the minimum distance between the pipeline and normally occupied buildings. In the British Standard PD 8010-1, for example, a substance factor is assigned and the distance is dependent on the substance being conveyed. The rationale is that the higher the substance factor, the more hazardous the fluid is and therefore the larger the distance between the pipeline and the buildings. The minimum distance for pipelines with categories C, D and E, excluding methane, and design factors not exceeding 0.72, the minimum building proximity distance, *Y*, is calculated using Equation 4.5. Depending on the code chosen and the assumptions made, there is a wide variation in the potential distance that a CO_2 pipeline should or could be located from a normally occupied building.. Clearly, and especially if multiple parallel pipelines are required, large safety distances may be impractical, for example, due to large population densities and also the location of existing pipeline infrastructure. This could have a major impact on siting. There is therefore a requirement to define the appropriate distances for supercritical CO_2 pipelines. These constraints would apply to countries adopting British Standards, or a regulatory structure consistent with them. In the United States, CO_2 pipelines have to conform to minimum standards appropriate to hazardous liquid pipelines whose only constraint is that they cannot pass within 15m of buildings. In fact most CO_2 pipelines in the USA are designed to more rigorous criteria than these.

9.2.7 Operational issues

It can be argued that early applications of CCS at power plants will mostly be at base load fossil fuel-burning power plants where it will be expected that a constant, steady flow of CO_2 will be produced for transport to safe geological storage. Even in this case, transient performance of pipelines must be considered since they must be operated safely if unexpected faults cause sudden changes in the flow of the CO_2 produced. Pipelines will also be required to accommodate power plant start-ups, shutdowns and electricity ramping for situations such as planned maintenance and variation in daily or seasonal demand. When CCS is rolled-out to more power plants it is unlikely, however, that all plants with CO_2 capture will produce a constant, steady flow of CO_2. Instead, it can be expected that many plants will operate flexibly to help with balancing supply and demand of electricity within the power network. This will lead to changes in the amount of CO_2 produced by the power plant. To what extend variations in CO_2 are passed to the pipeline (instead of venting) will depend on an interplay of capture technologies, pipeline economics, and CO_2 prices and regulations. Maximum CO_2 abatement would result if the CO_2 transport and storage system is designed to handle these, potentially rapid, transients taking place at the CO_2 capture sources. Since there is very little experience in managing transient CO_2 flow, as CO_2 pipelines currently being operated in the USA are mostly steady state, this represents an important knowledge gap that needs to be addressed when planning for a shared infrastructure. Flexibility of operation would be required for pipelines transporting anthropogenic CO_2. Flexibility may increase the design requirements (and hence costs) of pipelines and networks.

Modelling parameters

9.2.8 Design factors

$$Design\ Factor\ (a) = \frac{\sigma_{ah}}{e.\sigma_y} \qquad 4.1$$

where, *e* is the weld factor (generally equal to 1 in PD 8010-1); σ_{ah} is the allowable hoop stress; and σ_y is the yield stress of the material.

$$Stress = \sigma_{ah} = \frac{PD}{2t} \le \alpha\sigma_y \le \alpha SMYS \qquad 4.2$$

where σ_{ah} is the hoop stress, *P* is the internal pressure in the pipe, *D* is the pipe outside diameter and *t* is its thickness. SMYS is the Specified Minimum Yield Stress of the pipe material.

9.2.9 Flow equations

The equation for one dimensional fluid flow in a pipe corrected for the static head, H_c , and as cited by Schroeder (2001) is given by

$$Q = C\frac{T_b}{P_b}D^{2.5}e\left(\frac{P_1^2 - P_2^2 - H_c}{LGT_aZ_af}\right)^{0.5} \qquad 4.3$$

where: C is a constant; *D* is pipe internal diameter; e is the pipe efficiency, f is the Darcy-Weisbach friction factor; *G* is the gas specific gravity; *L* is the pipe length; P_b, P_1, and P_2 are the base, inlet and outlet pressures respectively; Q is the flow rate; T_a and T_b are the average and base temperatures respectively; and Z_a is the compressibility factor.

9.2.10 Erosional velocity

The erosional velocity, V_E, is determined by Equation 1 (Mohitpour *et al*, 2003):

Equation 1

$$V_E = \frac{C}{\sqrt{\rho_m}}$$

where C is a (dimensional) empirical constant representing the pipe material and ρ_m is the mixture density of the fluid. The value of *C* is of the order of 100 in Engineering units (API, 1981). More recent studies have shown that a *C* factor of 100 is very conservative and *C* factors of up to 400 for sand free operations have been proposed (Salama, 2000).

9.2.11 Building proximity distances

The building proximity distance, *Y*, calculated from Equation 2, and based on radiation distances

Equation 2

$$Y = Q\left(\frac{{D_0}^2}{32000} + \frac{D_0}{160} + 11\right)\left(\frac{p}{32} + 1.4\right)$$

where *p* is the internal design pressure, D_O is the outer diameter and *Q* is the substance factor given in PD 8010-1. However if the wall thickness is equal to or greater than 11.91 mm, the design factor does not exceed 0.3 and it is assumed that supercritical CO_2 is classified as a category E fluid, then the initial route may be established by allowing a minimum distance of 5.5 Q metres between the pipeline and occupied buildings[66].

66 A. Brown (personal communication).

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10 APPENDIX TWO – MODELLING ASSUMPTIONS

10.1 Assumptions on Aquifer Availability

Table 10 lists the assumptions used for modelling aquifer availability in the baseline and high aquifer scenarios in the study. As described elsewhere in the report there is currently no consensus GIS database of sink availability. Preparing this database would appear to be an urgent and important task that is essential for a realistic picture of CCS potential. However this is recognised to require a programme that is both resource intensive and potentially complex, in view of the likely requirement to consolidate data of various degrees of quality, held in different formats by different organisations and subject to contractual and intellectual property requirements. The present project schedule and resourcing did not permit an extensive standardisation of capacity estimates from different sources. The table below is intended for illustrative scenario development only – it does not constitute a global storage assessment endorsed by the authors or IEA GHG.

Table 10 Aquifer storage potential assumptions modelled in this study.

Region	Published aquifer storage capacity/Gt CO2	Reference	Modelled Capacity - assuming 2% of published/Mt CO2	Modelled Capacity - assuming 10% of published/Mt CO2
UK SNS Bunter Sandstone	14.7	IEA GHG Saline Aquifer Study	294	1,470
UK N&C North Sea	46	Scottish Carbon Capture Study	920	4,600
Poland	5.3	IEA GHG Saline Aquifer Study	106	530
Brazil (effective)	2000	IEA GHG Saline Aquifer Study	40000	200,000
Australia	700	IEA GHG Saline Aquifer Study	14000	70,000
China (onshore)	123	IEA GHG Saline Aquifer Study	2460	12,300
China (offshore)	38.8	IEA GHG Saline Aquifer Study	776	3,880
India	300	IEA GHG Saline Aquifer Study	6000	30,000
Denmark (11 structures)	16	IEA GHG Saline Aquifer Study	320	1,600
Germany	23	IEA GHG Saline Aquifer Study	460	2,300
Norway	13	IEA GHG Saline Aquifer Study	260	1,300
Netherlands	1.6	IEA GHG Saline Aquifer Study	32	160
Greece	2.2	IEA GHG Saline Aquifer Study	44	220
Belgium	0.1	IEA GHG Saline Aquifer Study	2	10
France (Paris Basin)	0.6	IEA GHG Saline Aquifer Study	12	60
S. Africa - Vryheid	18.4	IEA GHG Saline Aquifer Study	368	1,840
S. Africa - Katberg	1.6	IEA GHG Saline Aquifer Study	32	160
USA Big Sky	460.9	NatCarb2008 Atlas	9217	46,087
USA MGSC	29.2	NatCarb2008 Atlas	583	2,916
USA MRCSP	117.8	NatCarb2008 Atlas	2356	11,779
USA PCOR	185.6	NatCarb2008 Atlas	3712	18,559
USA SECARB	2,274.6	NatCarb2008 Atlas	45492	227,460
USA Southwest	10.7	NatCarb2008 Atlas	213	1,066
USA WESTCARB	204.9	NatCarb2008 Atlas	4098	20,492
Japan - Southwest Hokkaido	12.2	IEA GHG Saline Aquifer Study	244	1,220
Japan - Niigata	10.3	IEA GHG Saline Aquifer Study	206	1,030
Japan - Joban	10	IEA GHG Saline Aquifer Study	200	1,000
Japan - Toyama	2.2	IEA GHG Saline Aquifer Study	44	220
Japan - Kanto	12.4	IEA GHG Saline Aquifer Study	248	1,240
Brazil - Campos	4.8	IEA GHG Saline Aquifer Study	96	480
Brazil - Santos	148	IEA GHG Saline Aquifer Study	2960	14,800
Brazil - Solimoes	252	IEA GHG Saline Aquifer Study	5040	25,200
Brazil - Parana	462	IEA GHG Saline Aquifer Study	9240	46,200
Other Brazil	1133	IEA GHG Saline Aquifer Study	22660	113,300
Australia	750	IEA ETP Analysis	15000	75,000
Canada	2	Hendriks et al 2004	40	200
Ireland - Portpatrick Basin	2.7	Sustainable Energy Ireland study	54	270
Ireland - Central Irish Sea	17.3	Sustainable Energy Ireland study	346	1,730
Ireland - Lough Neagh Basin	1.9	Sustainable Energy Ireland study	38	190
Ireland - Kish Bank Basin	0.27	Sustainable Energy Ireland study	5	27
Ireland - East Irish Sea Basin	0.63	Sustainable Energy Ireland study	13	63
reland - Celtic Sea	17.3	Sustainable Energy Ireland study	346	1,730
Ireland - Peel Basin	68	Sustainable Energy Ireland study	1360	6,800
Ireland NWICB Dowra Basin	0.73	Sustainable Energy Ireland study	15	73
Total world aquifer storage	**9,496**		**189,913**	**949,600**

Where the data have been derived from diverse sources the storage estimates largely correspond to the theoretical capacity (as defined by the CSLF pyramid), however the following exceptions should be noted:

For US data, the data reflect 'CO_2 resources', as defined in the 'Methodology for Development of Geological Storage Estimates for Carbon Dioxide – Appendix B, prepared by the Capacity and Fairways Subgroup of the Geologic Working Group of the DoE Regional Carbon Sequestration Partnership (August 2008):

> *A CO_2 resource estimate includes all volumetric estimates of geologic CO_2 storage reflecting physical and chemical constraints or limitations (including potable water protection), but does not include current or projected economic constraints, regulations,*

> *or well and/or surface facility operations. Examples of physical constraints include isolation from potable waters, solubility of CO_2 in water, gravity segregation, injection formation fracture propagation pressure, caprock (or seal) capillary entry pressure, fracture propagation pressure, and displacement efficiency. Potable waters, for the purposes of Atlas II's assessment, represent waters protected by the Safe Drinking Water Act (SDWA). Additional geologic-based physical constraints include vertical thickness, proportion of porosity available for CO_2 storage, and fraction of the total area accessible to injected CO_2. Examples of chemical constraints are CO_2-brine solubility, brine concentration with depth, dissolution rates of CO_2 into brine, and precipitation (or mineralization) effects.*

For Canada[67] and South Africa[68], the published estimates used are based on very conservative analysis, which place these estimates closer to effective capacities rather than theoretical capacities. One published after the present analysis was completed indicates that the potential storage capacity in Canada may be orders of magnitude higher than quoted in the above table.

Combining the use of conservative assumptions on geological availability with a conservative assumption of overall availability (i.e. the 2% correction factor in the baseline or 10% in the high aquifer scenario) obviously has the potential to limit overall matched storage capacity. Whilst this is less of an issue for a report focussed on transport, the authors do recognise that as significant updates to data on sources, sinks and demand are published there would be merit in repeating the analysis to identify new constraints on transport.

10.2 Pipeline and boosting engineering equations used for modelling.

Pipeline engineering and cost calculations can be carried out to various degrees of precision, resources and data available. Inevitably with a model that seeks to forecast global pipeline infrastructure up to 2050, there are significant limitations on the amount and quantity of input data available. As such relatively simple but pragmatic models for engineering and cost calculations have been used[69]. These models have been reviewed and accepted as fit for purpose by several industry experts.

10.2.1 Pipeline diameter sizing

The diameter is calculated as a function of mass flow rate, velocity, and density, assuming turbulent flow, according to:

$$D = \left(\frac{Q_m}{v \cdot \pi \cdot 0.25 \cdot \rho} \right)^{0.5}$$

In this equation, *D* is the diameter in metres, Q is the mass flow rate in kg/s, v is the velocity in m/s and ρ is the density of CO_2 in kg/m^3 (typically 700-900 kg/m^3 in dense phase)

[67] See http://www.ecofys.com/com/publications/documents/GlobalCarbonDioxideStorage.pdf This quotes a range of 2-78 Gt CO_2 storage capacity for Canada, with 2 Gt corresponding to 'best' sites.

[68] See http://researchspace.csir.co.za/dspace/handle/10204/2567 or http://researchspace.csir.co.za/dspace/bitstream/10204/2567/3/Hietkamp_P_2008.pdf. These papers conclude that porosity and permeability in the Vryheid and Katberg formations are poor.

[69] Vanderginste and Piessens (2008) International Journal of Greenhouse Gas Control **2** (2008) 571-581.

10.2.2 Friction losses and Pressure drop

The pressure drop per metre pipeline is calculated in four steps. First the Reynolds number, Re, is calculated from density (ρ in kg/m^3), velocity (v in m/s), diameter (D in m) and dynamic viscosity (μ in Pa.s).

$$\mathrm{Re} = \rho v D / \mu$$

Second, the Darcy-Weisbach friction factor,*f*, is calculated from the diameter (D in m), roughness height (e in m) and Reynolds number.

$$f = 1.325 / \left[\ln((e/3.7D) + (5.74/\mathrm{Re}^{0.9}))\right]^2$$

Third, the Moody friction factor f_F is calculated from the Darcy-Weisbach friction factor *f*, according to

$$f_F = f/4$$

Fourth, neglecting topographic differences, the pressure drop per metre (Δp/L in N/m^3) is calculated from the Moody friction factor, the mass flow rate Qm, the density, and the diameter according to:

$$\Delta p / L = \frac{32 f_F Q_m{}^2}{\rho \pi^2 D^5}$$

10.2.3 Booster capacity requirements

Neglecting topographical differences, it is assumed that a booster unit is required when pressures reaches a lower limit threshold pressure as a result of friction. A lower limit could be set by the CO_2 phase behaviour, which depends on temperature and composition. A very crude estimate, that neglects the physical attributes of CO_2, for booster power (kW in Watts) can be identified from the volumetric flowrate (Q in m^3/s), the difference in pressure before and after boosting (Δp in kPa), and pump efficiency (η)

$$W = \frac{Q \cdot \Delta p}{\eta}$$

The number of boosters assigned is the minimum number that avoids pressure drops below the minimum pressure value. It is recommended that the engineering and cost models for CO_2 compression are reviewed as a separate study by IEA GHG.

10.2.4 Maximum separation distance between onshore boosters

The maximum separation distance between onshore boosters (in metres) is calculated from the pressure drop per metre and maximum and minimum pressures (in Pa) according to:

(Maximum pressure – Minimum pressure)/Pressure drop per metre

10.2.5 Booster energy requirements

The energy demand per booster per year is given by the booster capacity a load factor according to:

MWh/year =Booster capacity (in MW) x load factor (%) x 8760 (hours/year)

Parameter	***Typical values***
Minimum pressure	8-11 MPa
Maximum pressure	13-20 (default is15) MPa onshore 20-30 (default is 25) MPa offshore
CO_2 viscosity	6-10 (default is 8) x 10^{-5} Pa.s
CO_2 density	700-900 kg/m^3 (default is 800)
Surface roughness	0.0000457 m
CO_2 velocity	1-2 m/s onshore 2.5-4 m/s offshore
Booster efficiency	75%
Booster load factor	95%

Overall capital cost (excluding finance) = Capital cost of pipeline + Capital cost of boosters

Where :

Capital cost of pipeline (excluding finance) = \$ km^{-1} inch^{-1} x $\sum_{segments}$ *length x diameter x terrain weighting x regional weighting*

A default assumption of \$50,000, with an uncertainty of approximately ± \$20,000 km^{-1} inch^{-1} is used as suggested by data provided from FERC data compiled by the Oil and Gas journal and shown in . This value is inclusive of rights of way, labour, materials, contingency and owners costs. This approach requires less data than the recently updated IEA GHG pipeline calculator, but provides costs that are a similar order of magnitude.

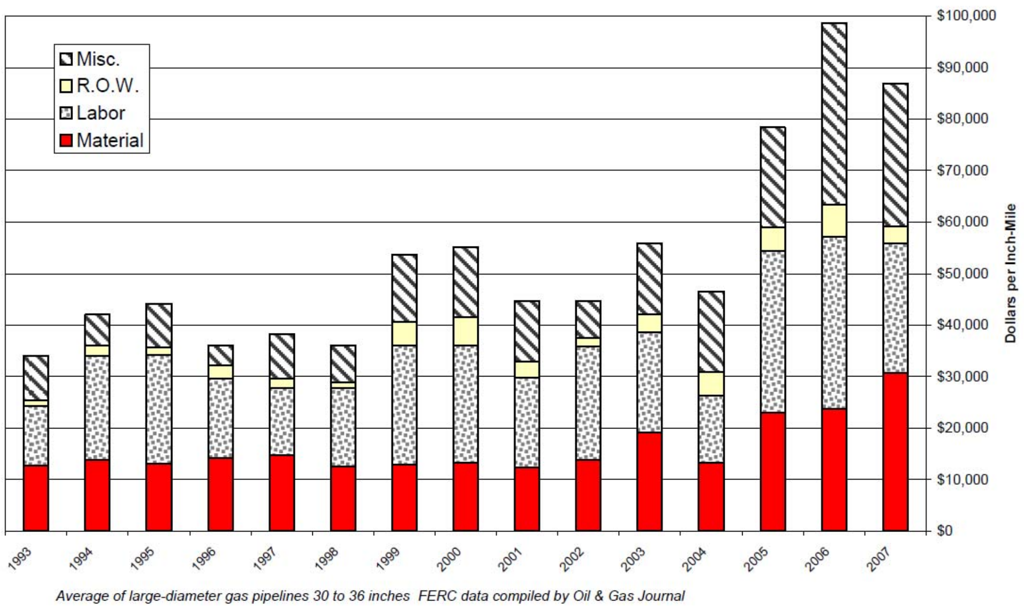


Figure 26 Prices for large diameter pipelines in North America. FERC data compiled by the Oil and Gas Journal.

Capital cost of boosters (excluding financing) = No. of boosters x booster capacity (in MW) x \$/MW x regional weighting.

The price of compressors pumps/boosters is \$1m-\$10m/MW. For this study a default value of \$ 6 m/MW is used (note this includes associated infrastructure, land, standard levels of redundancy). Consistent with the IEA GHG pipeline model, factors are used to weight the costs of pipelines in different terrains. These multiplication factors are listed below .

Table 11 Terrain cost multipliers

Terrain	Cost multiplier
Flat open countryside	1
Mountainous	2.5
Desert	1.3
Forest	3
Offshore (up to 500 m water depth)	1.6
Offshore (above 500 m water depth)	2.7

The costs of pipelines differ between regions. These differences can be captured using the multiplication factors shown below:

Table 12 Regional cost multipliers

Region	**Cost multiplier**
Africa	0.8
Australasia	1
Canada	1
Central and South America	0.8
China	0.7
Eastern Europe	0.8
CIS	0.7
India	0.7
Japan	1
Mexico	0.8
Middle east	0.9
Other Developing Asia	0.8
South Korea	0.8
USA	1
Western Europe	1

The annual operating costs for pipelines and boosters are conveniently represented as percentages of capital costs.

Table 13 Operating costs (as percentages of capex)

Description	Annual opex as a % of capex
Onshore pipeline	1.5%
Offshore pipeline	3%
Boosters (onshore only)	5%

11 APPENDIX THREE - THE RELATIVE ECONOMICS OF POINT-TO-POINT VS. INTEGRATED PIPELINE INFRASTRUCTURE

Four compelling configurations for CO_2 transport infrastructure required to connect multiple sources to multiple sinks are A) independent point-to-point pipelines, B) shared integrated pipeline infrastructure; C) independent pipelines that share common rights-of-way and D) shipping.

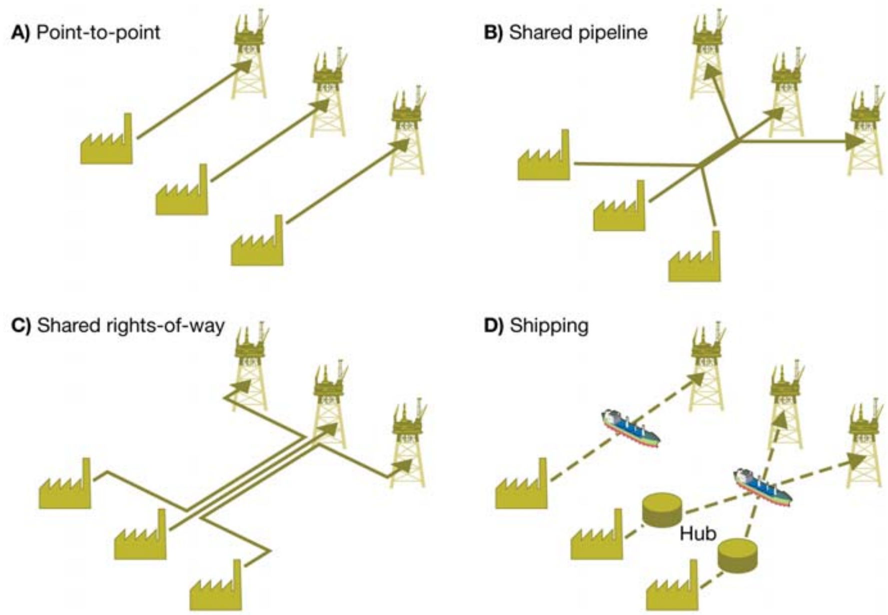


Figure 27 Schematic of options for transport network topologies. A) Point-to-point; B) 'Shared' or 'Integrated' pipeline; C) Shared rights-of-way; D) Shipping

This appendix illustrates quantitatively the impacts of (i) geometry, (ii) discount/interest rates, (iii) capacity, and (iv) timing, on the relative economics of point to point vs. integrated infrastructure.

For ease of understanding, in each example the analysis is applied for two sources connected to a common hub or sink, on a flat and simple terrain with no routing challenges. In practice, the idealized configurations shown are unlikely to be achieved in practice – but they nevertheless provide some high level insight into the relative impacts of the above factors, although it is recognised that situation-specific issues may dominate this generalised analysis. The cost of pipeline is modelled as \$50,000/km/inch with annual opex at 5% of capex. Boosting requirements and costs are not considered. Tax, depreciation, risk premium are not modelled.

11.1 Geometry

For simplicity, consider two sources of equal emissions (10 Mt CO_2/year) that are equidistant (100 km) from a common hub or sink on identical terrain. Assume further that both sources begin and finish capturing CO_2 in the same year.
The Figure below illustrates five scenarios, where source A and source B, where the source-sink-source angle increases from 0° (scenario 1), 30°, 45°, 60°, and 90° (scenario 5).

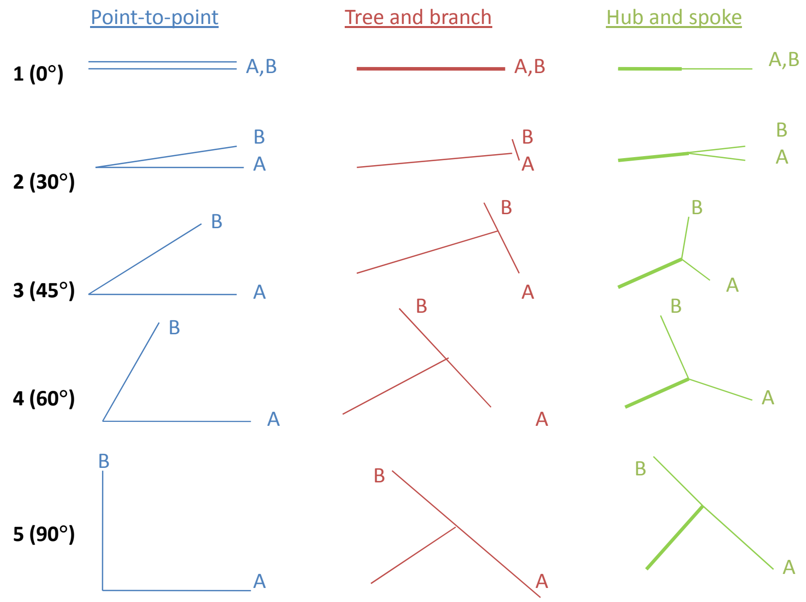


Figure 28 Archetypal configurations for two sources (A and B) connected to a common hub or sink. Scenarios 1-5 illustrate increasing source-sink-source angle.

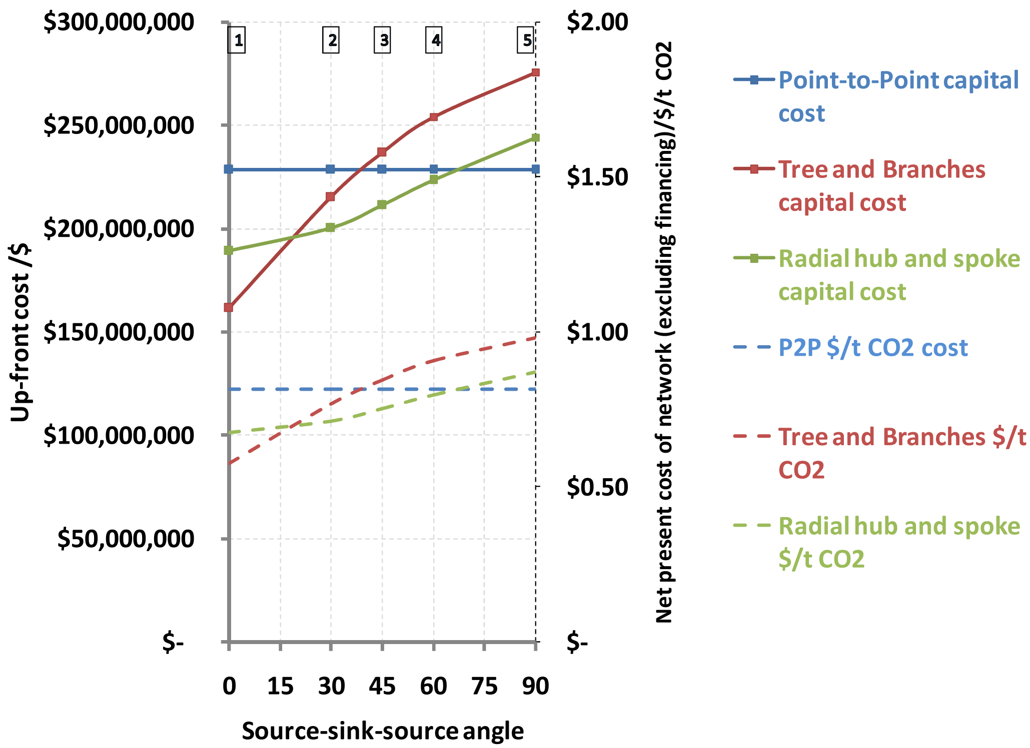


Figure 29 Impact of geometry on up-front (left-hand axis) and average costs (excluding financing but with operating costs discounted at 5%) for pipeline networks described by Scenarios 1-5.

If the sink source sink angle is substantially above 60°, the geometry does not permit any useful cost saving through infrastructure sharing. As the source-sink-source angle decreases from 60 to 30 degrees, a radial hub and spoke geometry with a hub at the centroid of the triangle formed by source A, source B and the sink would appear to offer the lowest costs. When the source-sink-source angle is below 15 degrees, a simple tree structure, with perpendicular branches offers the lowest cost solution in this situation. Figure 30 provides similar information but incorporates the cost of financing at 10%, and costs are then expressed as the constant average user tariff required to achieve an overall project NPV of 0 in year 20.

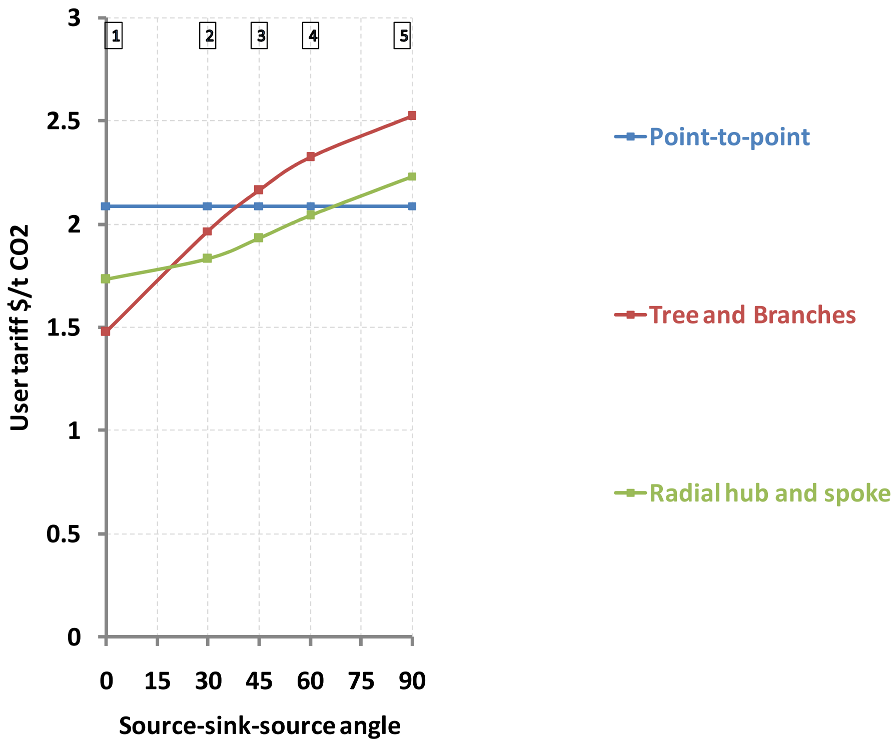


Figure 30 User tariff as a function of source-sink-source angle (including cost of financing at 10% with a pipeline economic lifetime of 20 years).

11.2 Financing

Consider two sources with equal capture volumes (10 Mt CO_2/year), equidistant from a common sink (or hub). The source-sink-source angle is 30 degrees, i.e. the situation represents one where a radial hub-and-spoke integrated pipeline infrastructure is expected to be the cheaper than point-to-point infrastructure. For this scenario, we have examined the impact of increasing cost of capital on the user tariff (set as equal for A and B) and on loan length. The tariff is calculated to ensure that the project NPV at the end of the economic lifetime (default twenty years from date of commissioning) is zero, i.e. the modified internal rate of return equals the weighted average cost of capital in year 20. A default construction period of three years is assumed, with capital costs distributed equally through this period.

11.2.1 Cost of capital (i.e. discount rate)

For simplicity, it is assumed that a single WACC is applied. Construction begins three years prior to commissioning, and loan repayments begin in year 0 and cease at the end of the economic lifetime of the pipeline, modelled as 20 years from commissioning.

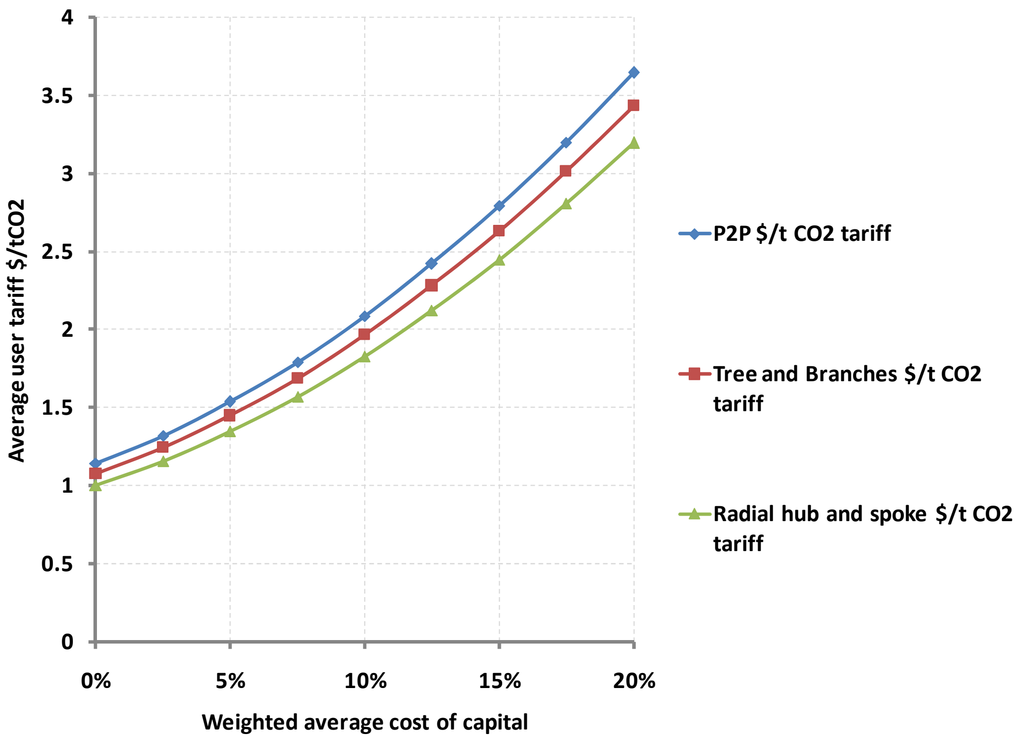


Figure 31 User tariff increases with cost of capital for a network with two sources of 10 Mt CO2/year both 100 km from a common sink (or hub), with a source-sink-source angle of 30 degrees.

In contrast, the impact on average user tariff from increasing the loan repayment period is very limited as shown below.

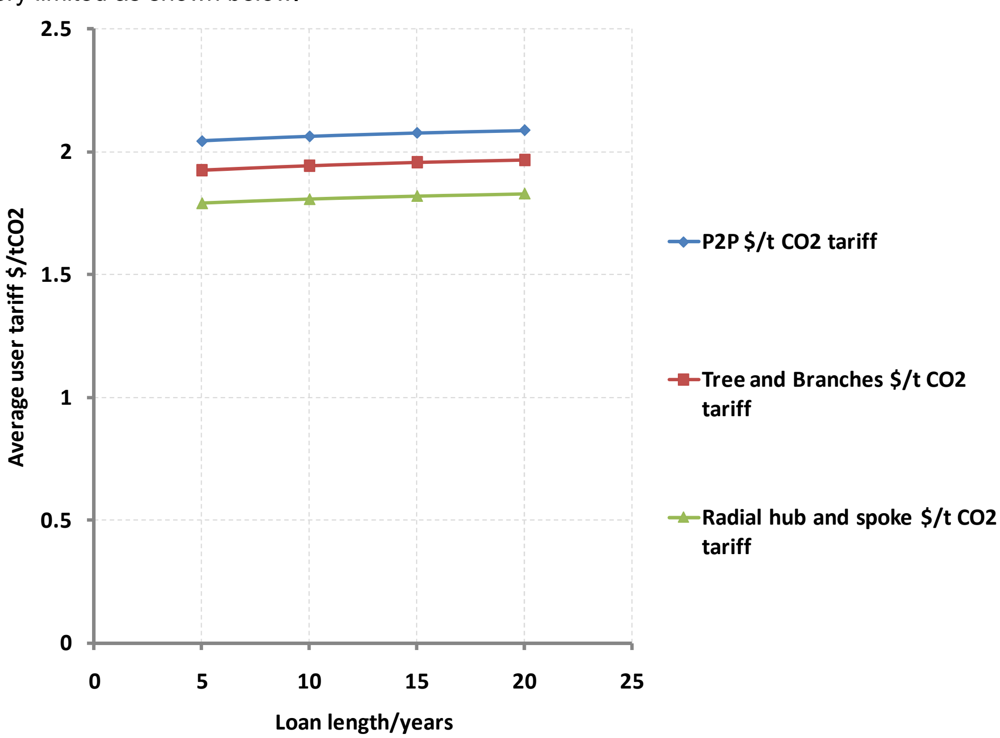


Figure 32 Impact of loan length on user tariff (at 10% WACC)

11.3 Capacity

11.3.1 Sources having equal capacity

Consider two sources with equal capture volumes, equidistant (100 km) from a common sink (or hub). The source-sink-source angle is 30 degrees, i.e. the situation represents one where a radial integrated pipeline infrastructure is expected to be the cheaper than point-to-point infrastructure. For this scenario, we have examined the impact of absolute capacity on the user tariff (set as equal for A and B), assuming a WACC at 10% and economic lifetime of 20 years.

As shown below, there is a decrease in cost as the capacity of sources increases. For sources below 1 Mt CO2/year (i.e. a combined volume of 2 Mt CO_2/year) tariffs for transport exceed \$5/t CO_2 and rise rapidly for small volumes in this configuration. Conversely for sources above 10 Mt CO_2/year (i.e. a combined volume of 20 Mt CO_2/year), economies of scale for this configuration are largely realized.

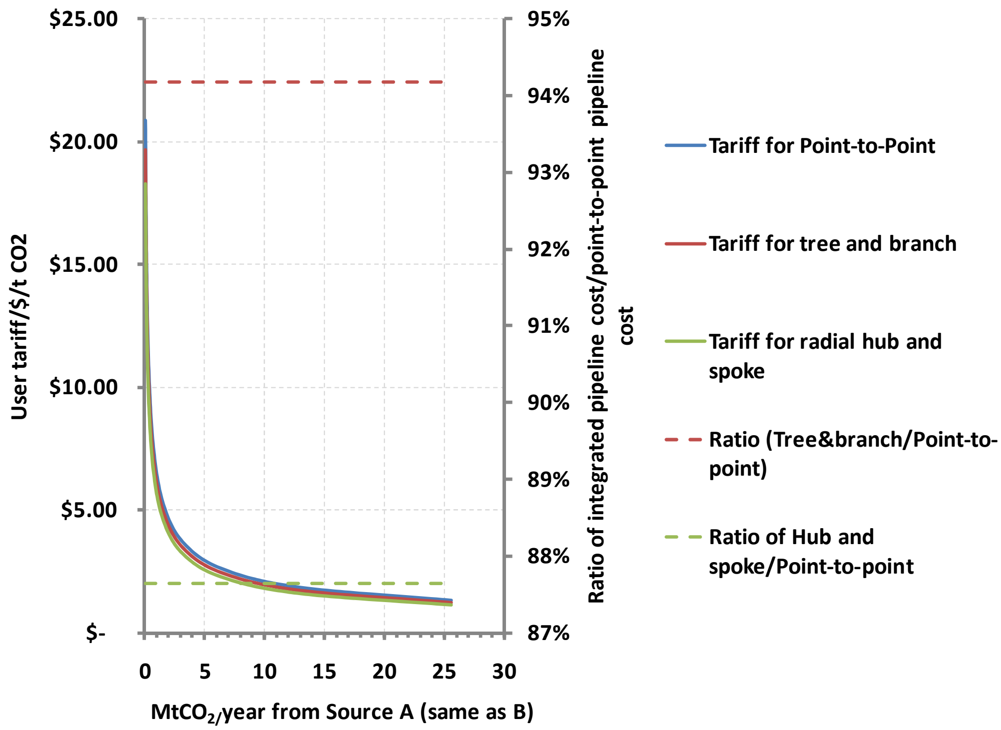


Figure 33 Pipeline economies of scale: Impact of source capacity on pipeline tariffs and relative economics of central vs. integrated pipelines

The ratios of costs of integrated pipeline infrastructure vs point-to-point infrastructure as a function of scale (dashed red and green lines). These lines are flat, confirming that, for this configuration, the benefits of integrated pipeline infrastructure are independent of capacity.

11.3.2 Sources having different capacity

We examine now a situation as above, but where capture from source A is fixed at 10 Mt CO_2/year and the capture volumes from source B are varied from 0.1 Mt CO2/year up to 10 Mt CO_2/year. As above, sources A and B are both located 100 km from the sink (or hub) and the source-sink-source angle is 30 degrees. As previously, the pipeline tariff is calculated to provide an NPV of zero twenty years after commissioning. WACC is assumed as 10% (assumed as 100% loan financed with a loan of 20 years, repayments beginning in the year of commissioning).

As the capacity of source B grows, the construction costs for the networks obviously increase, shown in the bold lines in the figure below. If B is below 0.8 Mt CO_2/year, the least capital cost geometry corresponds to a tree and branch structure. However above this size, the least capital cost geometry corresponds to a radial hub and spoke structure.

In this configuration, the tariff structure is important. If A and B are charged the same tariff, corresponding to the average system cost, if B is smaller than A, it is always cheaper for B to join an integrated network (red or green dashed lines) with A in this configuration than to operate a separate pipeline (pink dotted line). The smaller B is, the more compelling is the decision to share a pipeline with source A.

However, for source A, the relative economics of independent vs. integrated infrastructure are critically dependent on the size of source B, and increase as the Mt CO_2/year from B increases. When B is larger than 5 Mt CO_2/year, then the shared infrastructure solutions start to become cheaper.

Importantly, when B is small, then the average tariff for shared infrastructure is higher than the cost of an independent pipeline from source A to the sink. If both source A and B pay the same $/t CO_2 pipeline tariff, then under these conditions A would benefit from bypassing the common infrastructure and developing its own pipeline.

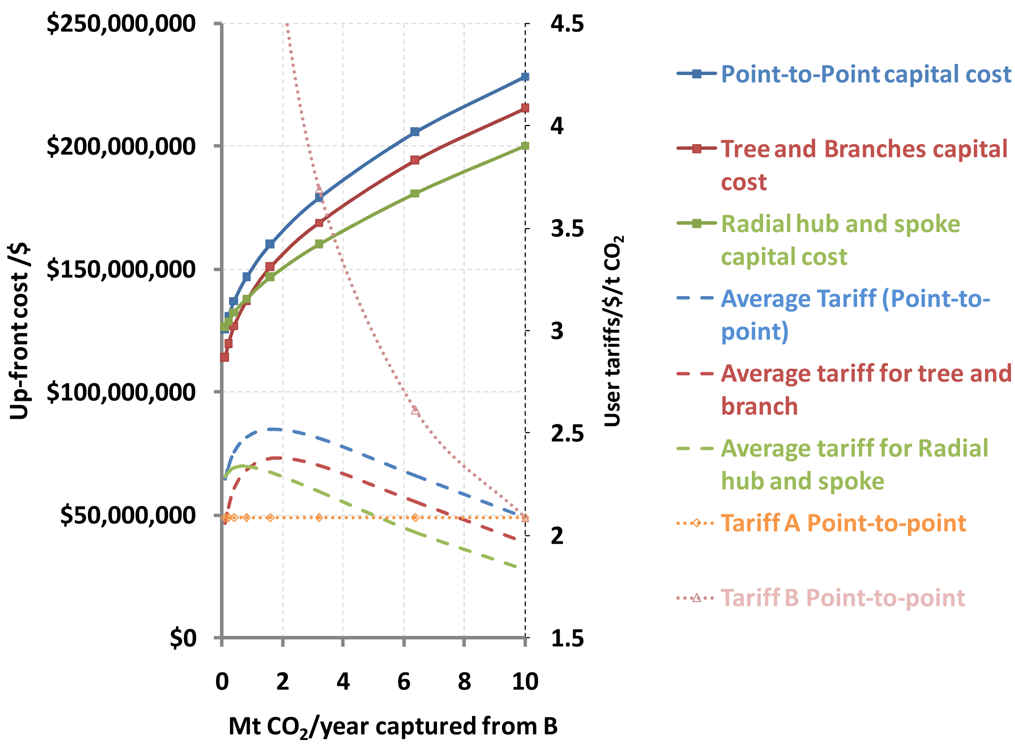


Figure 34 Impact of capacity of source B on construction costs and user tariffs. Dashed blue, red and green lines denote average tariffs as seen from a whole system (or societal) perspective.

The relative economics of infrastructure financing community has developed complex tariff structures to address scenarios such as this, where the benefits for individual actors are not well aligned with those of the system as a whole.

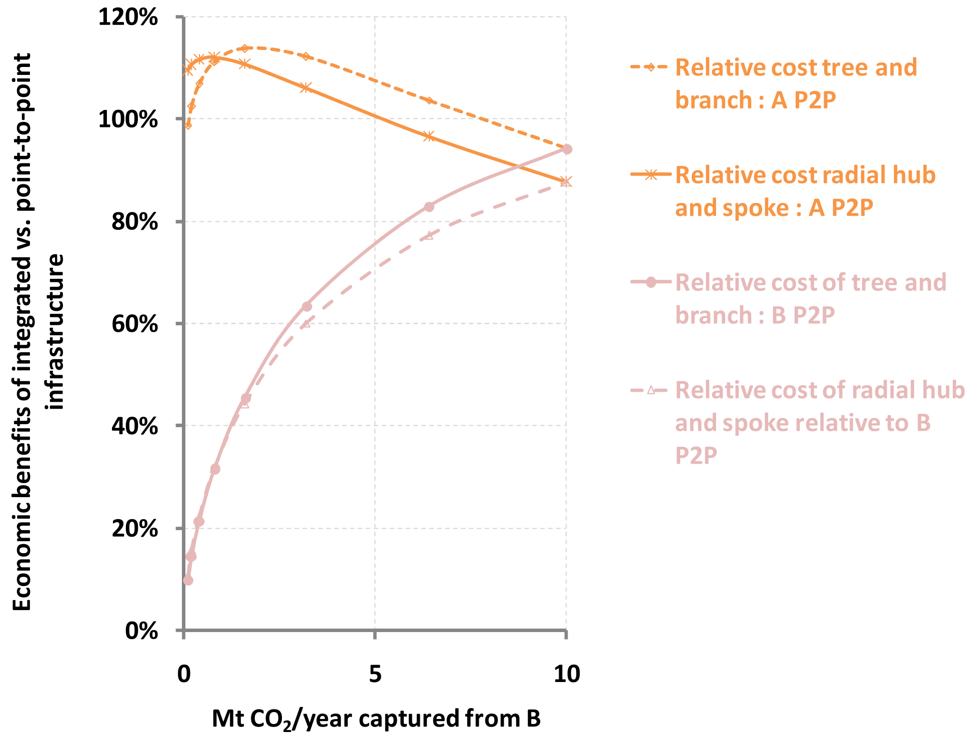


Figure 35 Relative benefits of integrated infrastructure viewed from the perspectives of A (orange lines) and B (pink lines)

11.4 Lifetime

If the loan period is constant at 20 years (or the project must have achieved a Modified Internal Rate of Return of 10% in year 20), then reducing operational lifetime below 20 years clearly increases the average annual tariff required. Increasing operation and revenues beyond 20 years provides no further average tariff reduction if the investment appraisal period is fixed at 20 years. Beyond 20 years, the loan is assumed to be fully paid, and therefore tariffs can be reduced if desired to cover ongoing costs only.

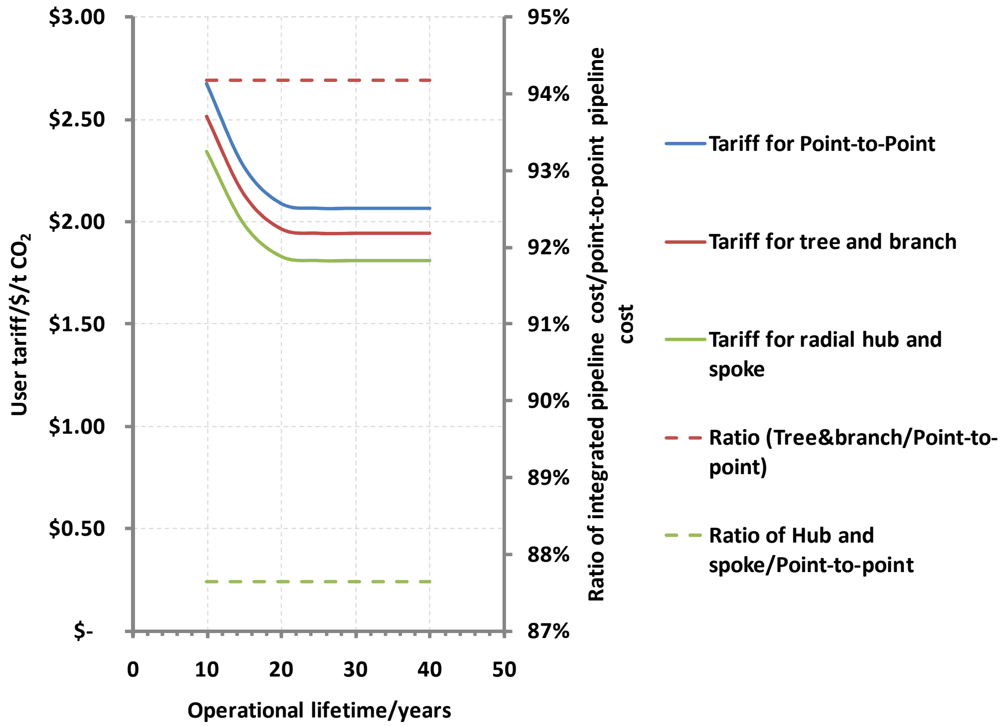


Figure 36 Variation of tariff required with operational lifetime (assuming a fixed investment appraisal period of 20 years)

However, if the loan and investment appraisal period can be extended to match the operational lifetime of the pipeline directly, then there are benefits to longer operation. Beyond twenty years these benefits decrease. For example, the tariff reduces by around 50 ¢ in extending the operation and loan lifetimes from 10 years to 20 years but only 4 ¢ in going from 30 years to 40 years as shown in the Figure below.

In this configuration the relative economics of point-to-point and integrated infrastructure are unchanged by operational lifetime or economic lifetime.

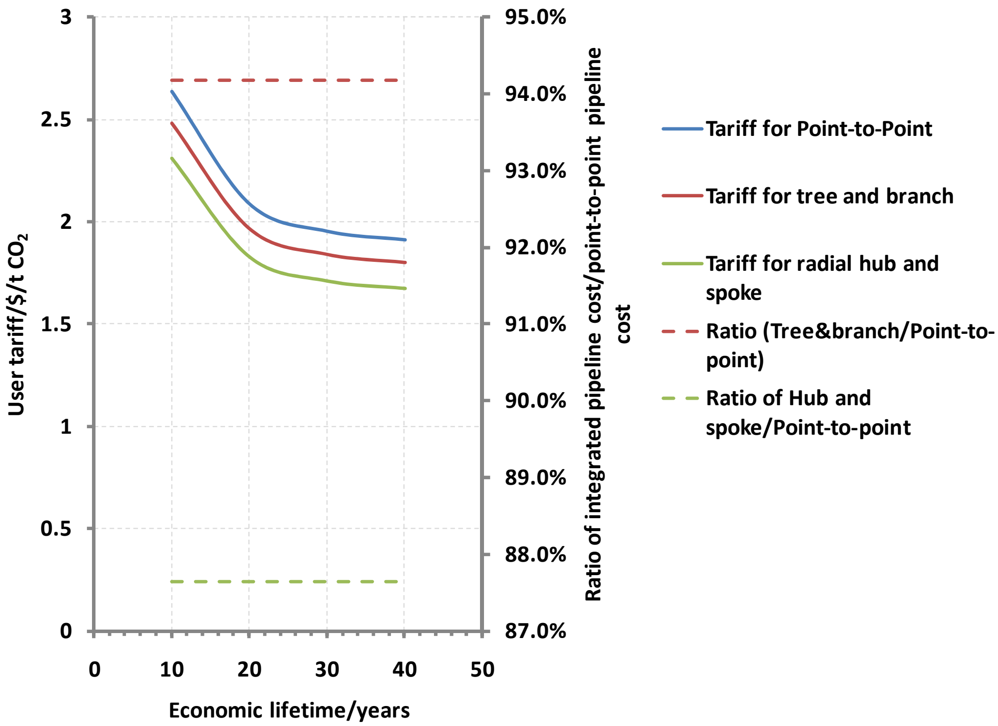


Figure 37 Impact of economic lifetime on tariffs for CO2 pipelines where operational lifetime matches investment appraisal period.

11.5 Phasing

For a single source using a pipeline, a delay between construction and operation in the early years can have a marked impact on the average tariff required, assuming that the economic life of the pipeline is fixed (e.g. 20 years after construction is completed). The Figure below shows that the impact of a delay of four years can raise the average tariff required by 50%, from ca. \$2/t to \$3/t CO_2 for a single pipeline connected to a source of capacity 10 Mt CO_2/year.

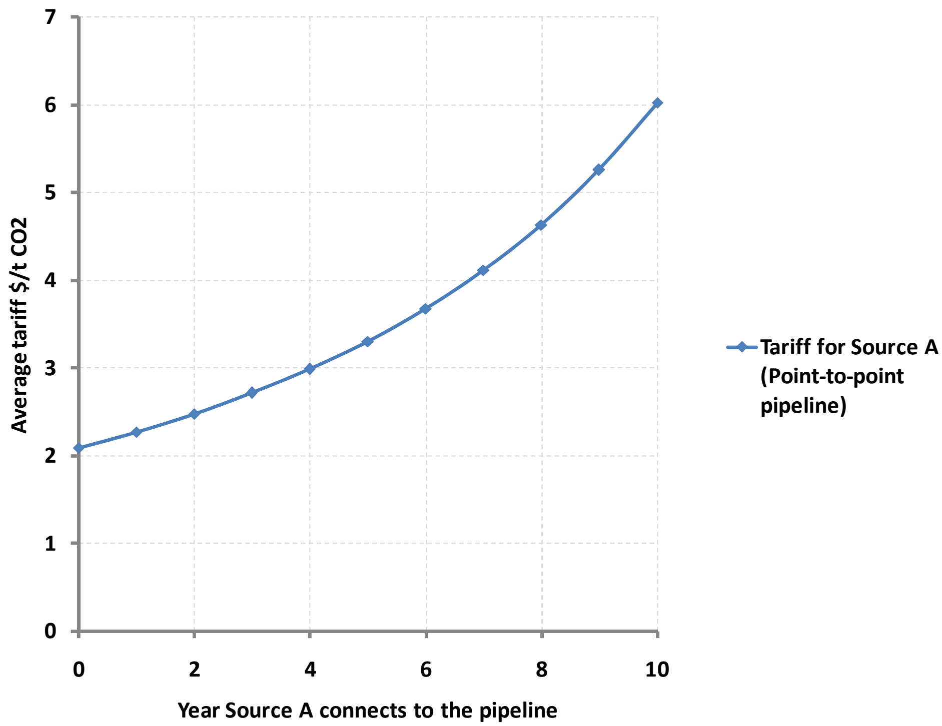


Figure 38 Importance of early connection: Tariff required for 10 Mt CO_2/year capture source as a function of number of years delay in connecting to pipeline. Pipeline NPV at year 20 = 0. WACC = 10%.

A major uncertainty when multiple sources connect to a network is the timing of connection of subsequent sources. This is illustrated for two sources with equal emissions at the same site, 100 km from the sink (or hub). Assuming a fixed economic lifetime of 20 years, increasing the delay between the connection of source A (assumed to connect in year 0) and source B connecting increases the average tariff required. In the example shown, as long as source B connects before year 7, integrated infrastructure benefits both sources A and B. However if source B connects after year 9, source A must pay a higher average tariff for integrated infrastructure than the tariff for independent infrastructure. For this configuration, the radial hub and spoke provides an interesting alternative between fully integrated and fully separated pipelines, as it is less sensitive to delayed utilization than the integrated pipeline infrastructure, but still captures some of the benefits.

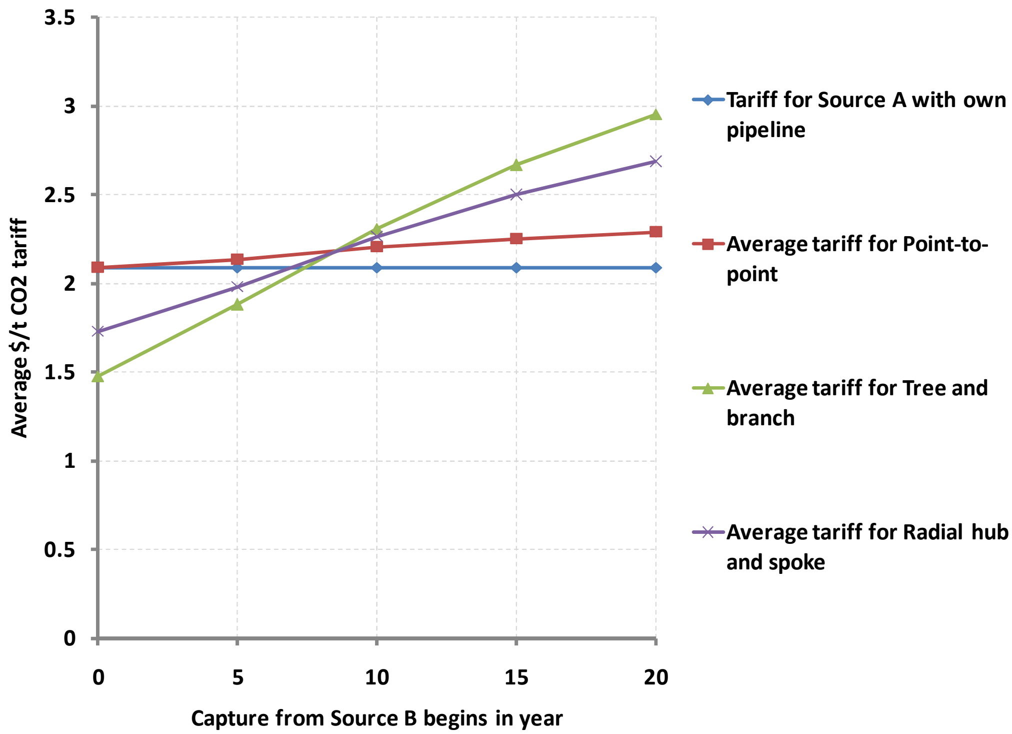


Figure 39 Pipeline tariffs for integrated and pipeline infrastructure as a function of the delay between transporting from source A and from source B, located at the same point, with equal emissions of 10 Mt CO2/year each. Transport from source A begins in year 0. The system NPV at year 20 is 0.

11.5.1 Construction period

Delays in construction increase costs through (i) increased interest during construction; (ii) reduced operation and thus revenues prior to any fixed project economic lifetime; and (iii) potential requirement to compensate e.g. payment for CO_2 emissions. For a single source connecting to a single pipeline the inherent economics of construction times on the pipeline can be isolated from payments for CO_2 credits.

As shown below, reduction of construction period from 3 years to 1 year reduces the average tariff by 11%, whereas increasing the construction period from 3 years to 5 years increases the average tariff required by 10%. These differences are likely to be small compared to penalties e.g. CO_2 prices and possible requirements to compensate investors in capture (or storage) facilities.

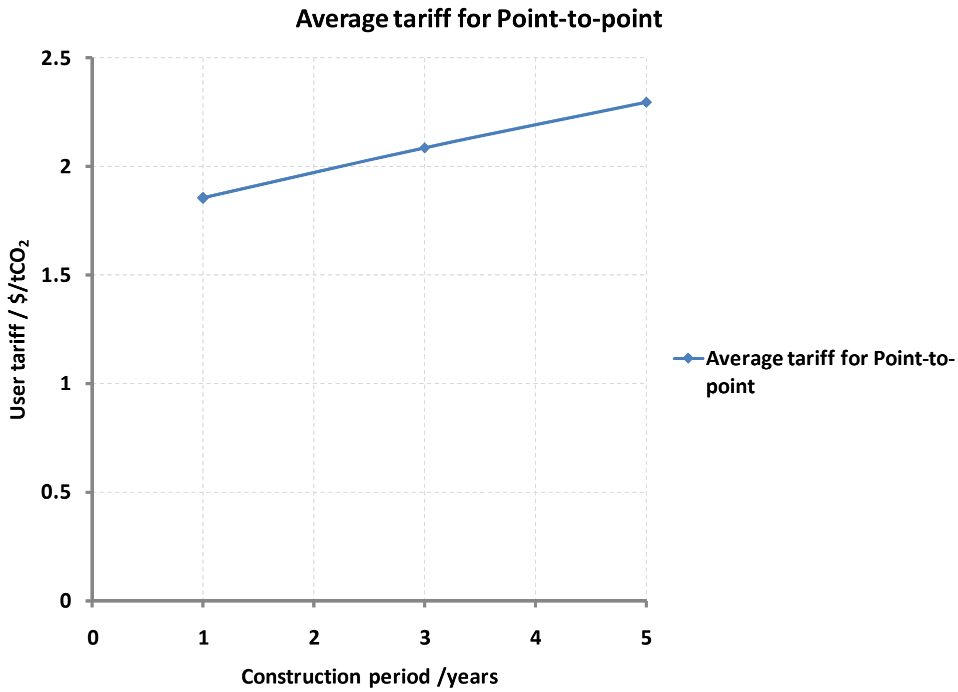


Figure 40 Impact of construction period on tariff for a single pipeline user (10 Mt CO2/year, 100 km from sink (or hub)). WACC is 10%.

11.6 Conclusion on costs of independent vs. integrated pipeline infrastructure

For a simple system with two sources connected to a common sink, the cashflow modelling confirms the following decreasing order of importance for key drivers:

- The longer the pipeline length the higher the tariff required.
- The smaller the absolute capacity the higher the tariff required.
- The higher the weighted average cost of capital the higher the tariff required.
- The longer the economic lifetime and loan period the lower the tariff required.
- The longer the delay between construction and operation, the higher the tariff required (N.B. excludes payments for CO_2 emissions in the gap)
- The longer the construction period, the higher the tariff required (N.B. excludes payments for CO_2 emissions in the gap).

These drivers have similar effects for integrated and point-to-point infrastructure. In a limited number of cases transport costs can be reduced by encouraging capture from sources near to sinks. However the flexibility to do this may be constrained by diverse forces. The analysis suggests that the priority for public intervention has to be to reduce the economic risks and thereby reduce the cost of capital for investment in pipeline infrastructure. This could be achieved through development of stable well-designed long-term regulatory and incentive frameworks.

The high level analysis shows that the factors which favour integrated pipeline infrastructure over independent point-to-point pipelines are (in order of decreasing importance):

- Geometry, only smaller source-sink-source angles favour integrated infrastructure.
- Relative capacity – small sources benefit substantially from sharing infrastructure with a larger source, although this can increase costs for the larger source in some scenarios.

- Close phasing of sources, with very short delays between the first and second source connecting to the same network.

The analysis does not examine the 'option' value for sources from having a transport network ready for use although this could be material[70].

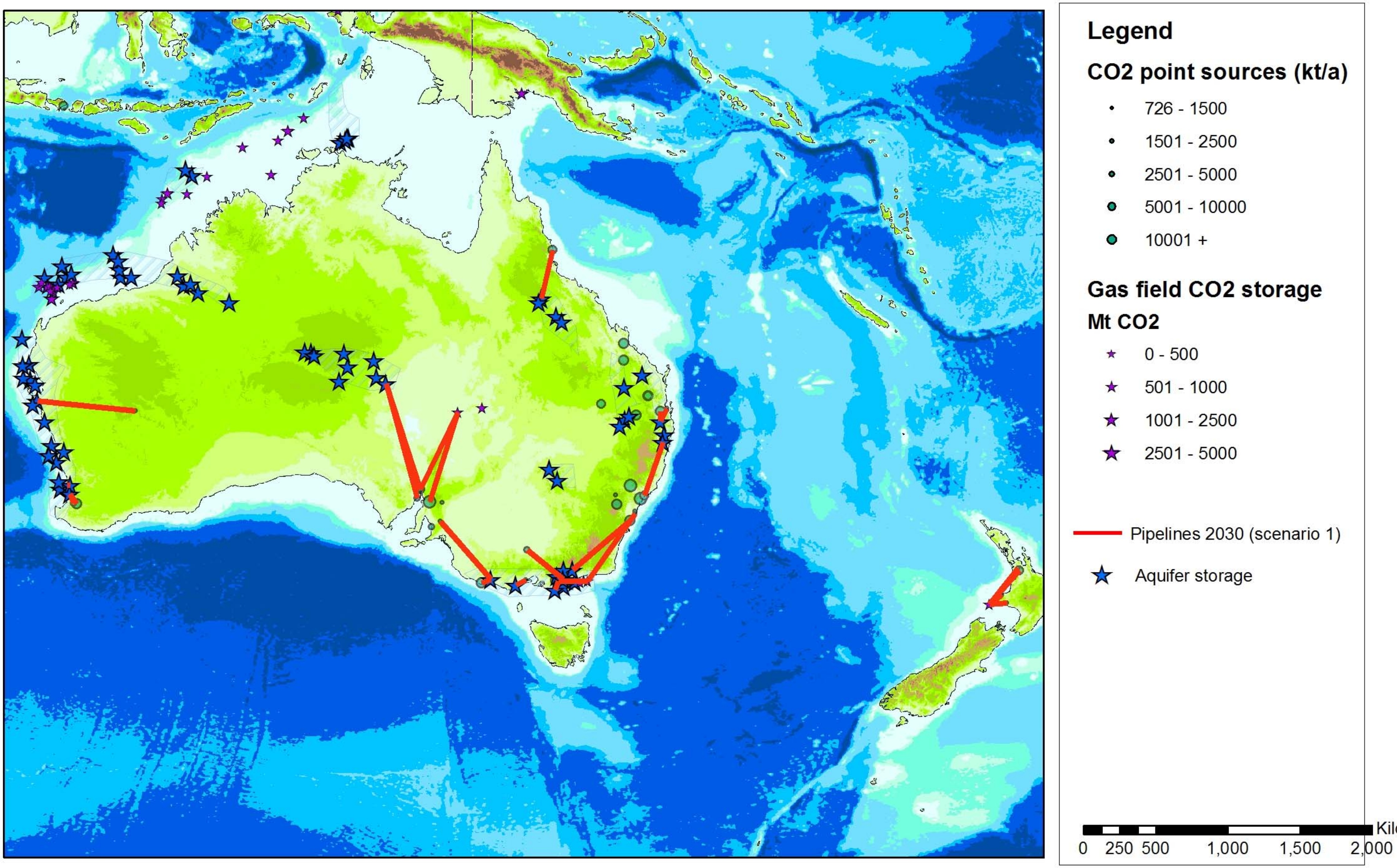
With immense uncertainties over capture and storage potential, and with widely different geographical and economic circumstances, it is extremely difficult to make robust long-term decisions now on a regional or national networks for CO_2 that successfully balance flexibility, scalability, costs, risks, benefits, and also account for the implicit messages sent by public investment in point-to-point vs. 'oversized' infrastructure.

Therefore there is a case for infrastructure deployment to proceed stepwise in the 2010s, gaining experience from small-scale point-to-point pipelines (or shipping) before very expensive integrated international systems are developed in the 2020s and later to connect multiple sources and sinks. In regions where uncertainty over demand or storage capacities are extremely high, point-to-point networks may be the preferred options – reducing the risk of stranded assets. If so, it may be possible to capture many of the benefits of integrated infrastructure by ensuring that rights-of-way are reserved to permit multiple pipelines along the same route. This would reduce or eliminate the planning and consenting risks and timescales for subsequent projects, without requiring economically inefficient or excessive up-front investments.

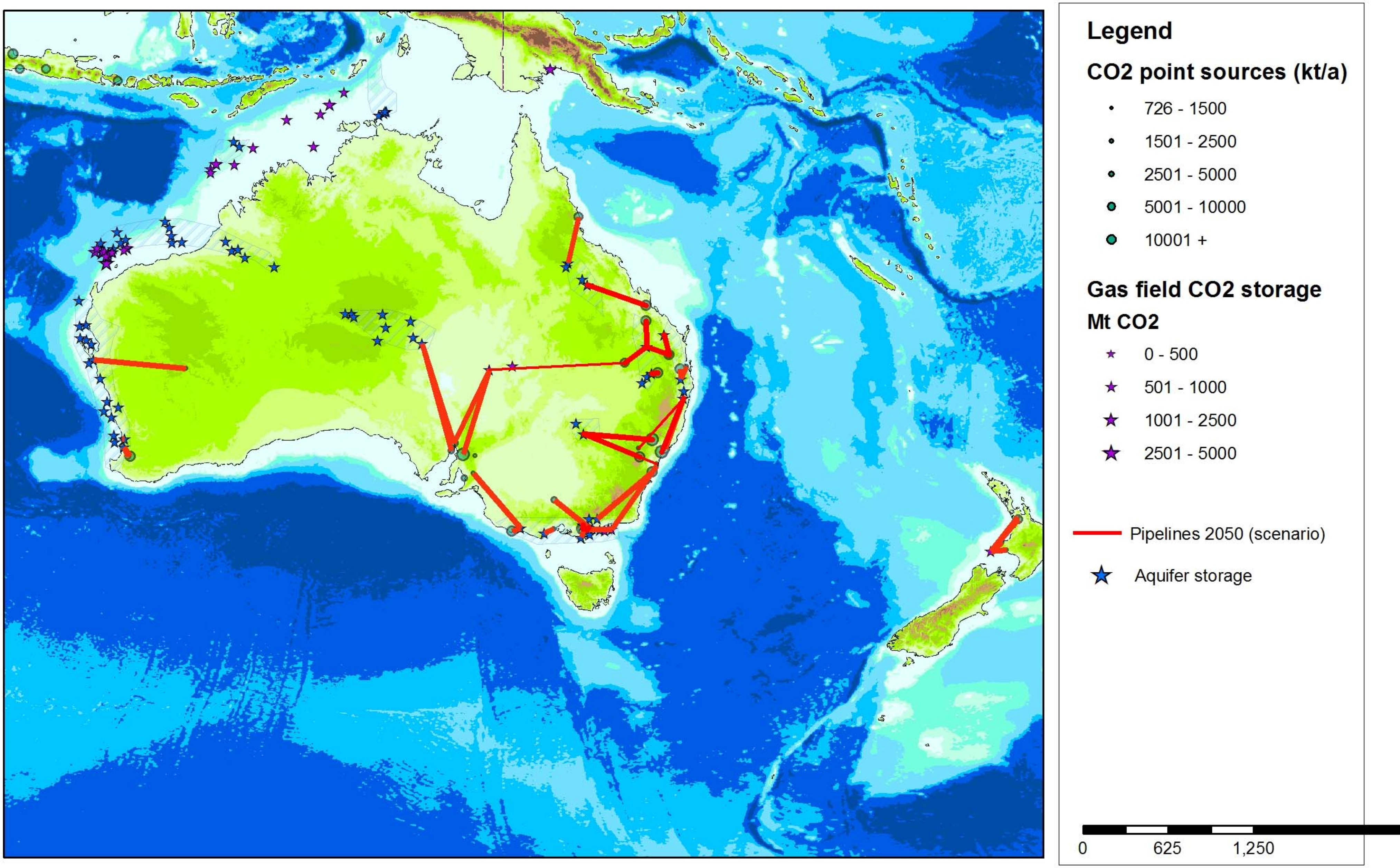
[70] J. Gibbins (2009) Imperial College London, *Personal Communication*

List of maps

A map of networks to meet CCS demand (using aquifers and gas fields) in 2030



A map of networks to meet blue map CCS demand in 2050



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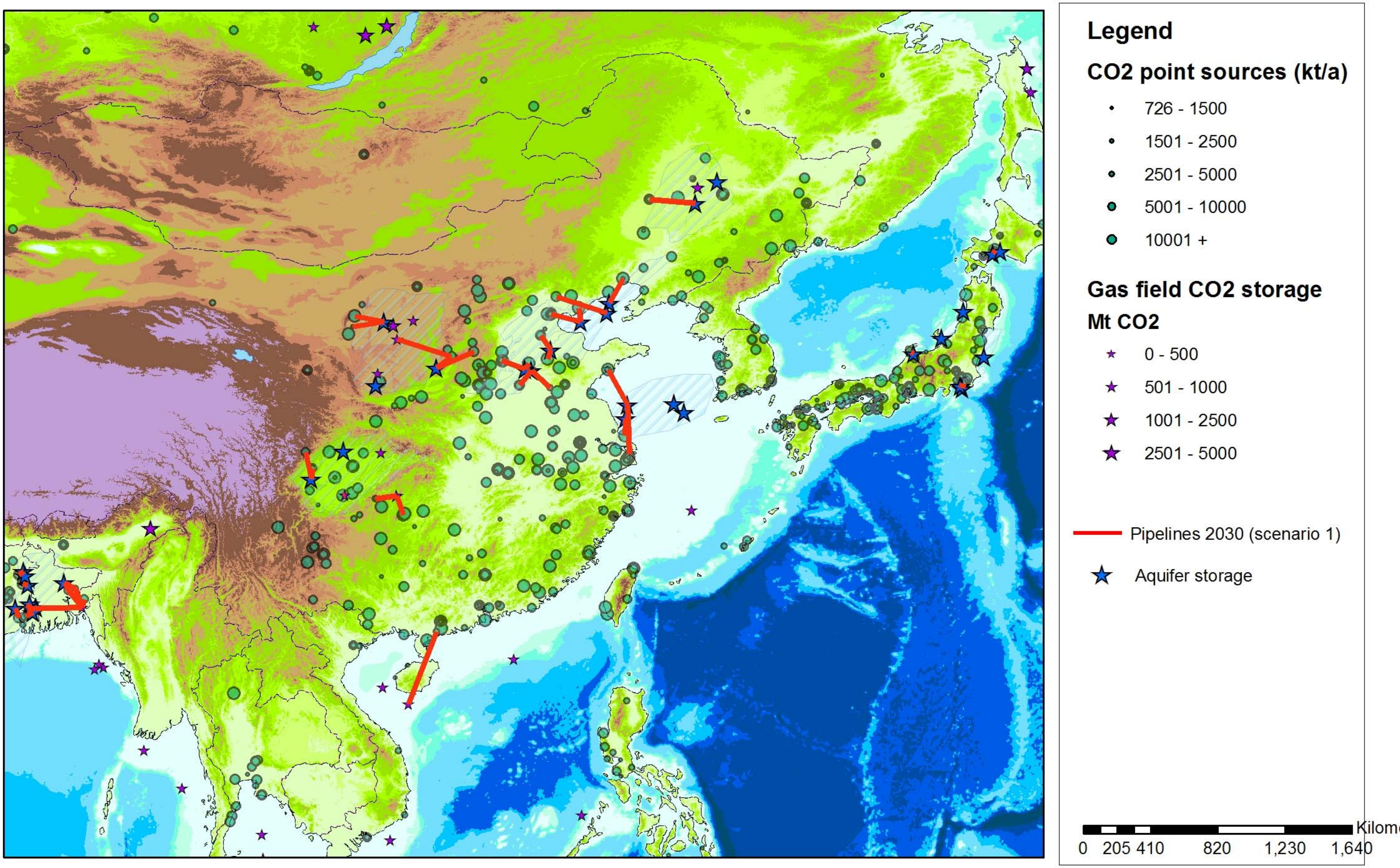

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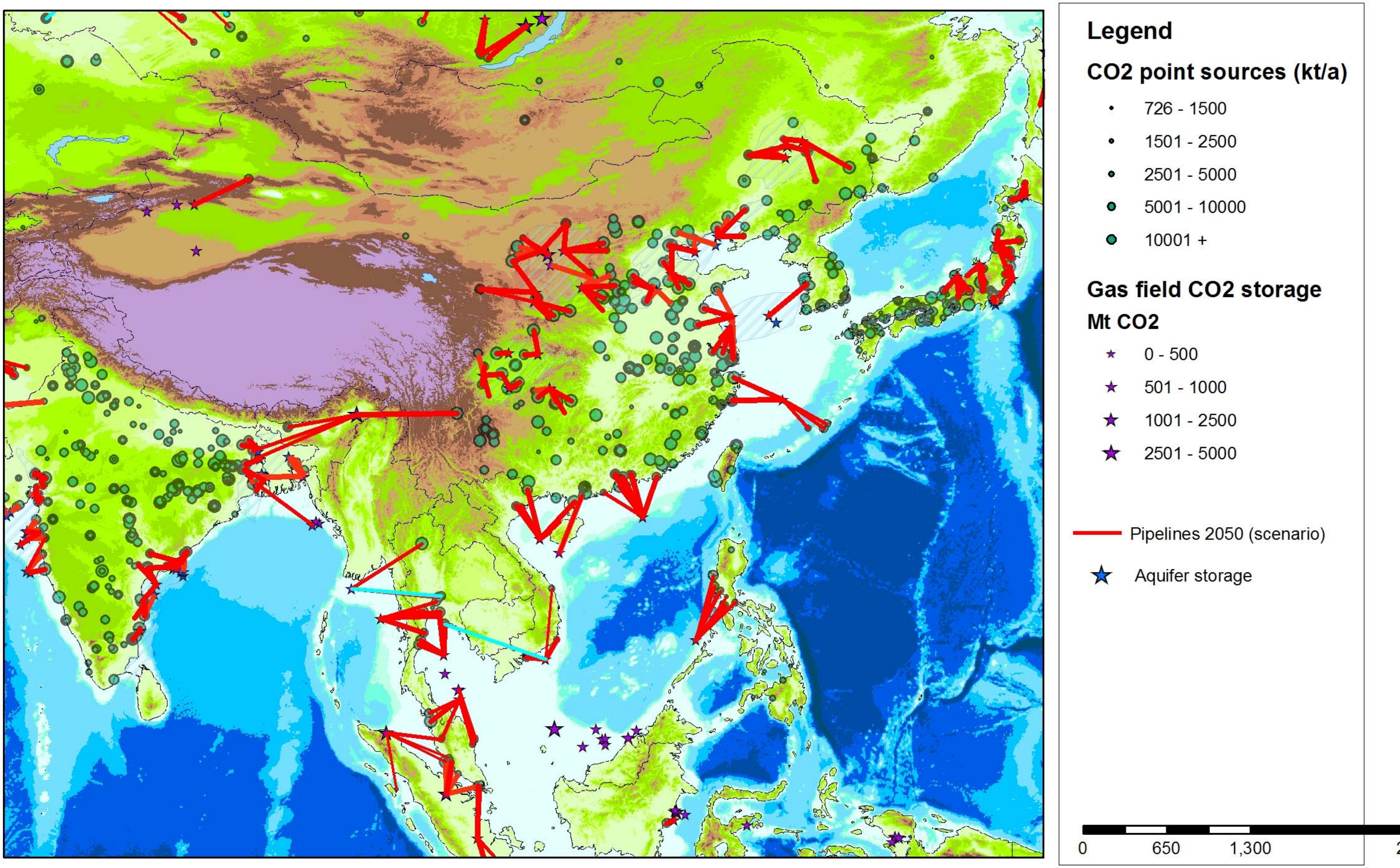

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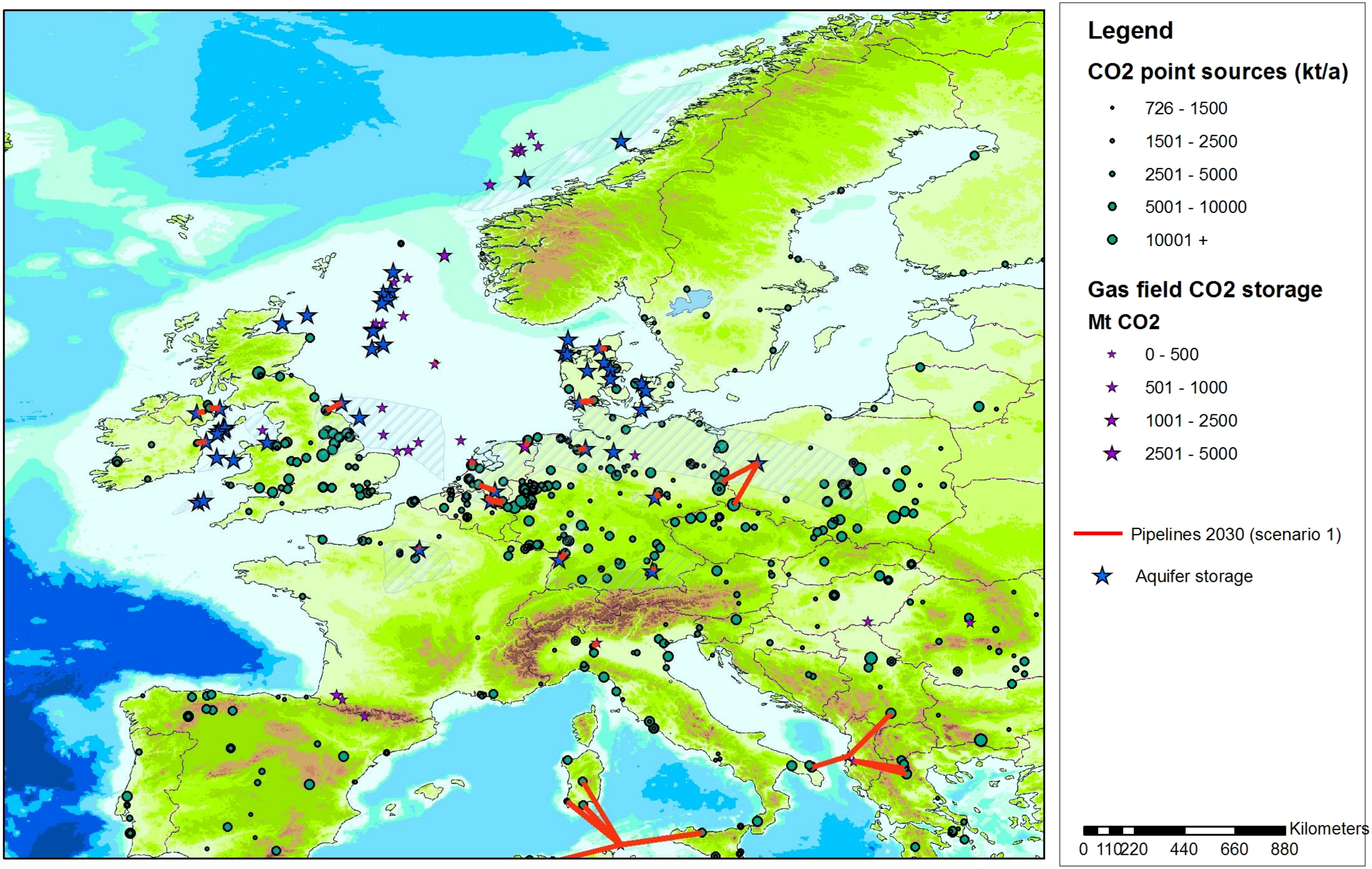

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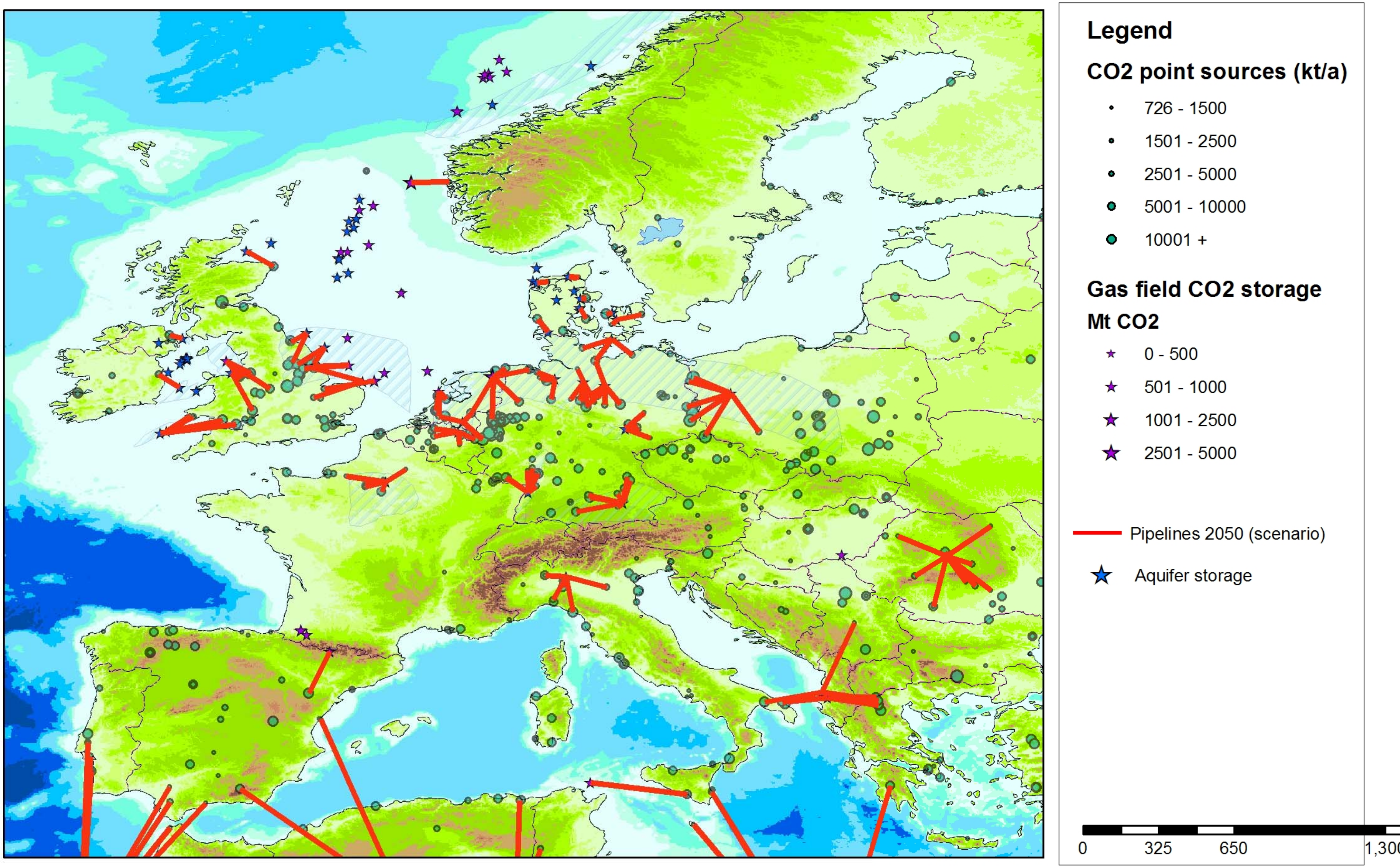

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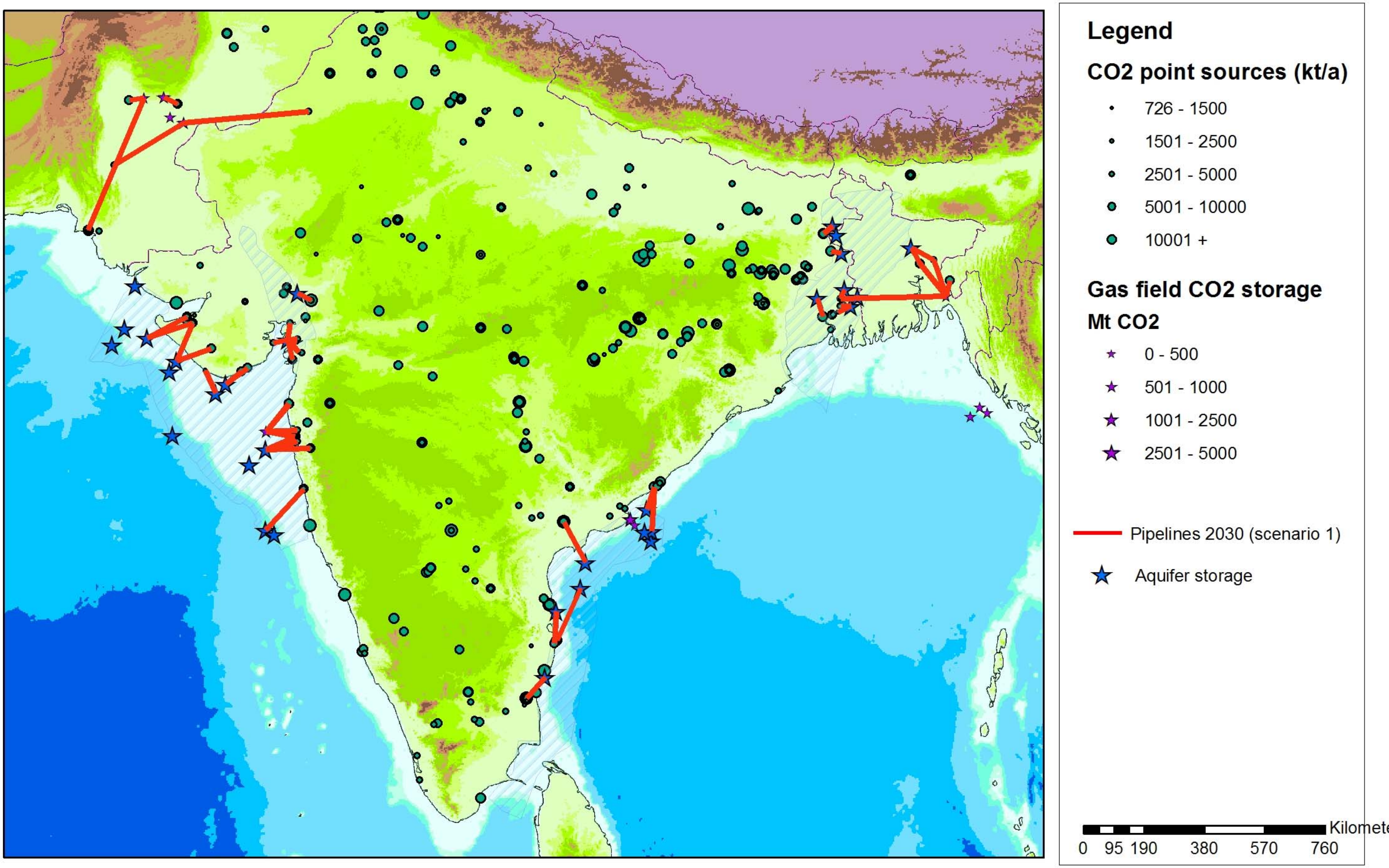

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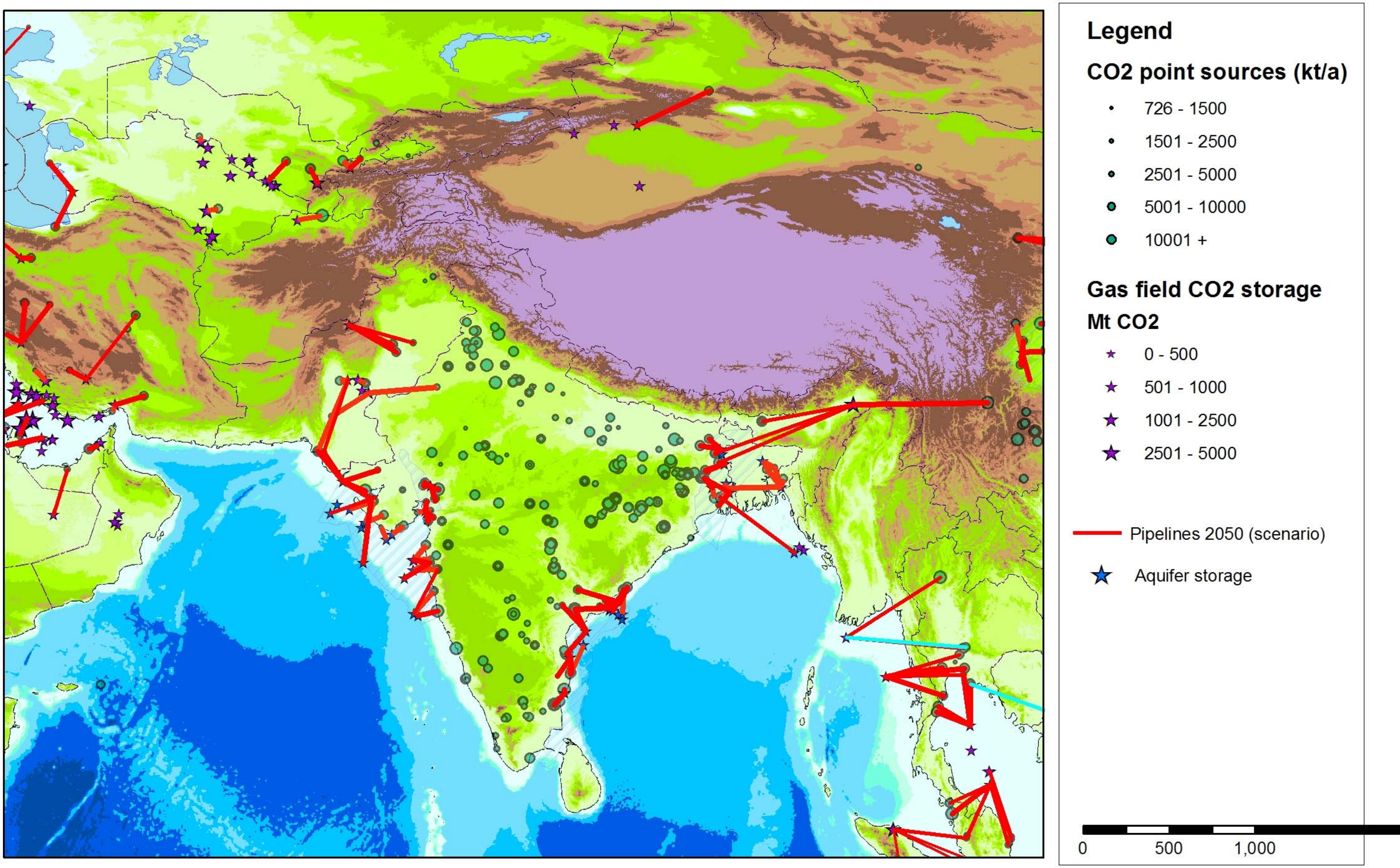

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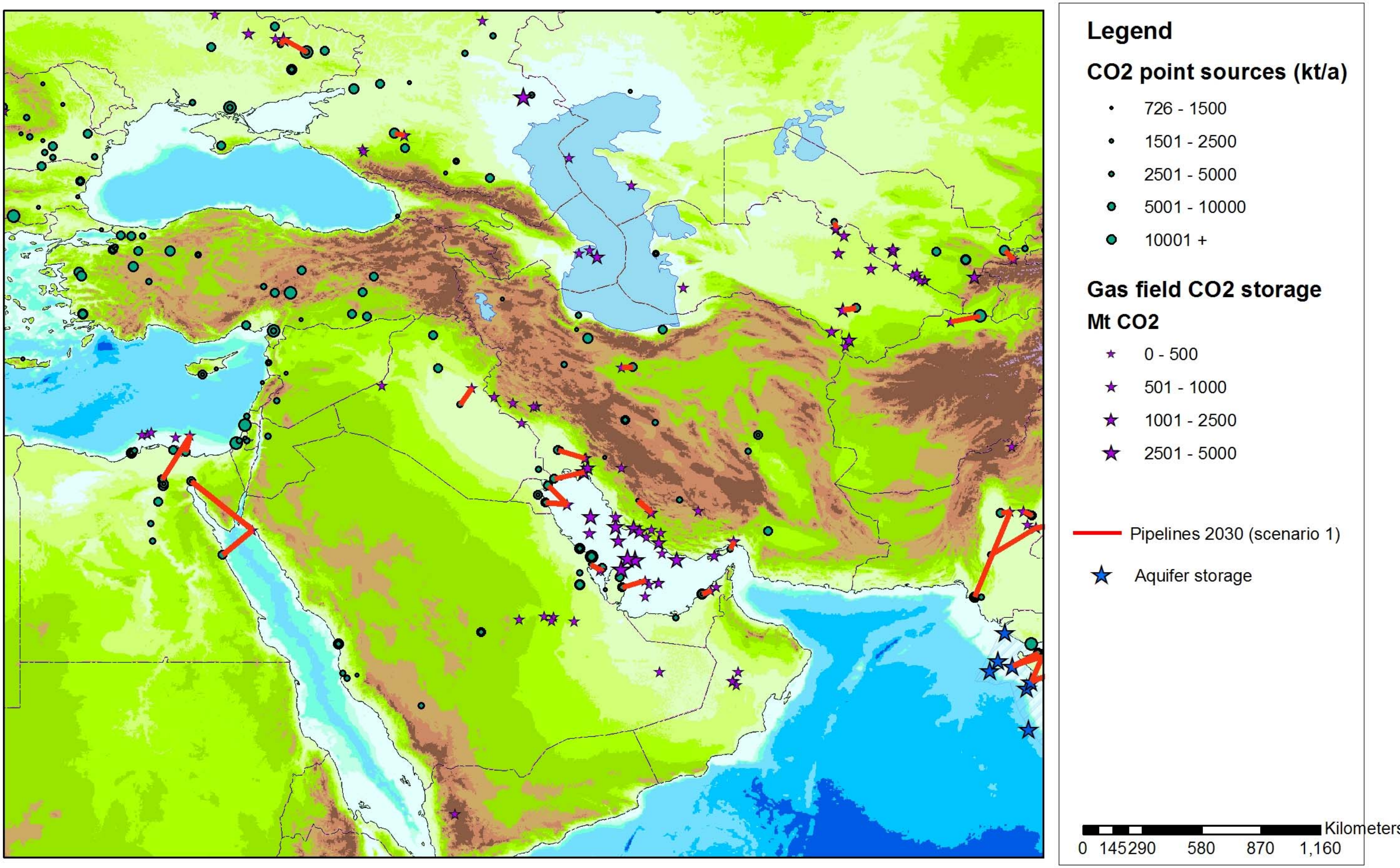

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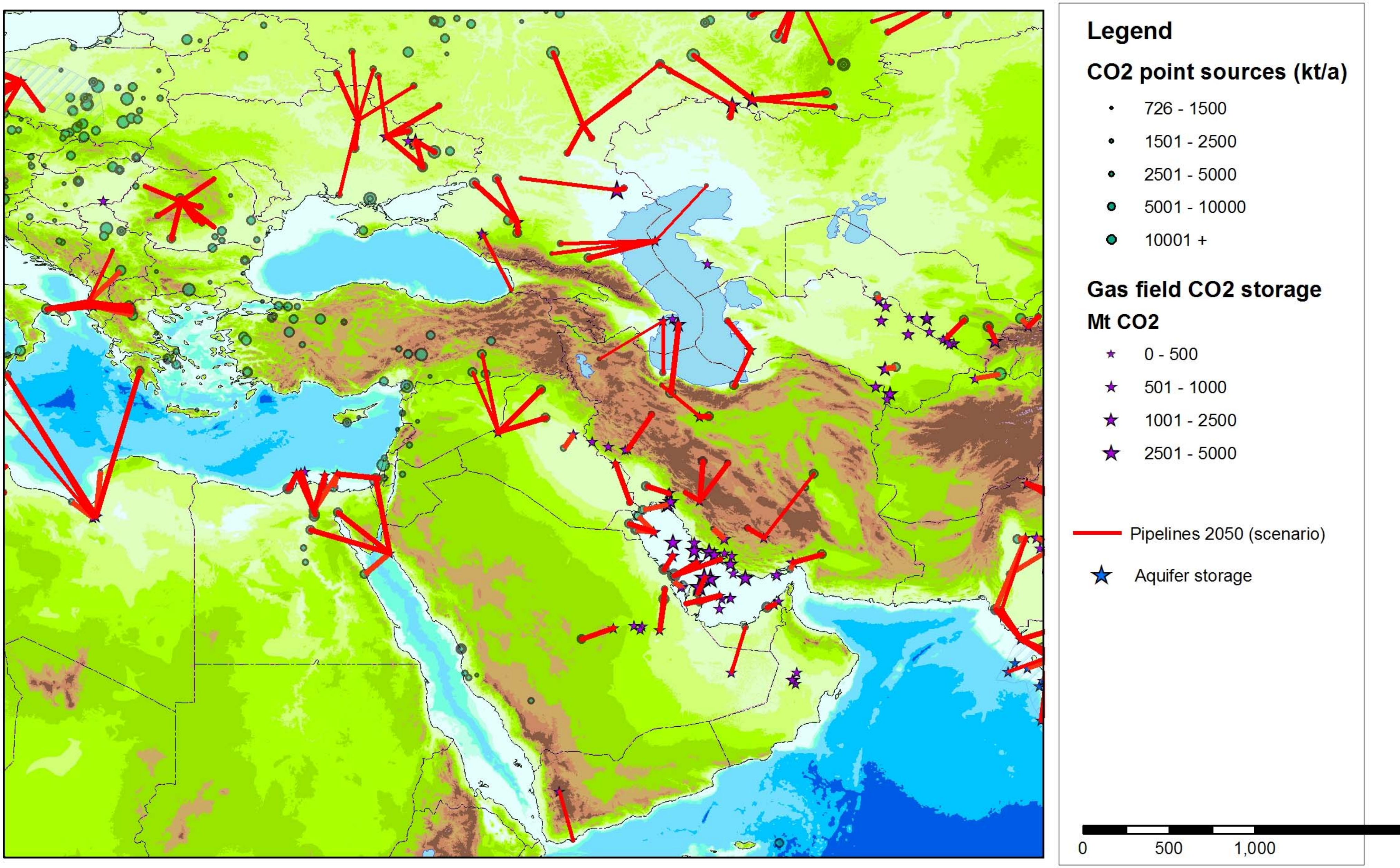

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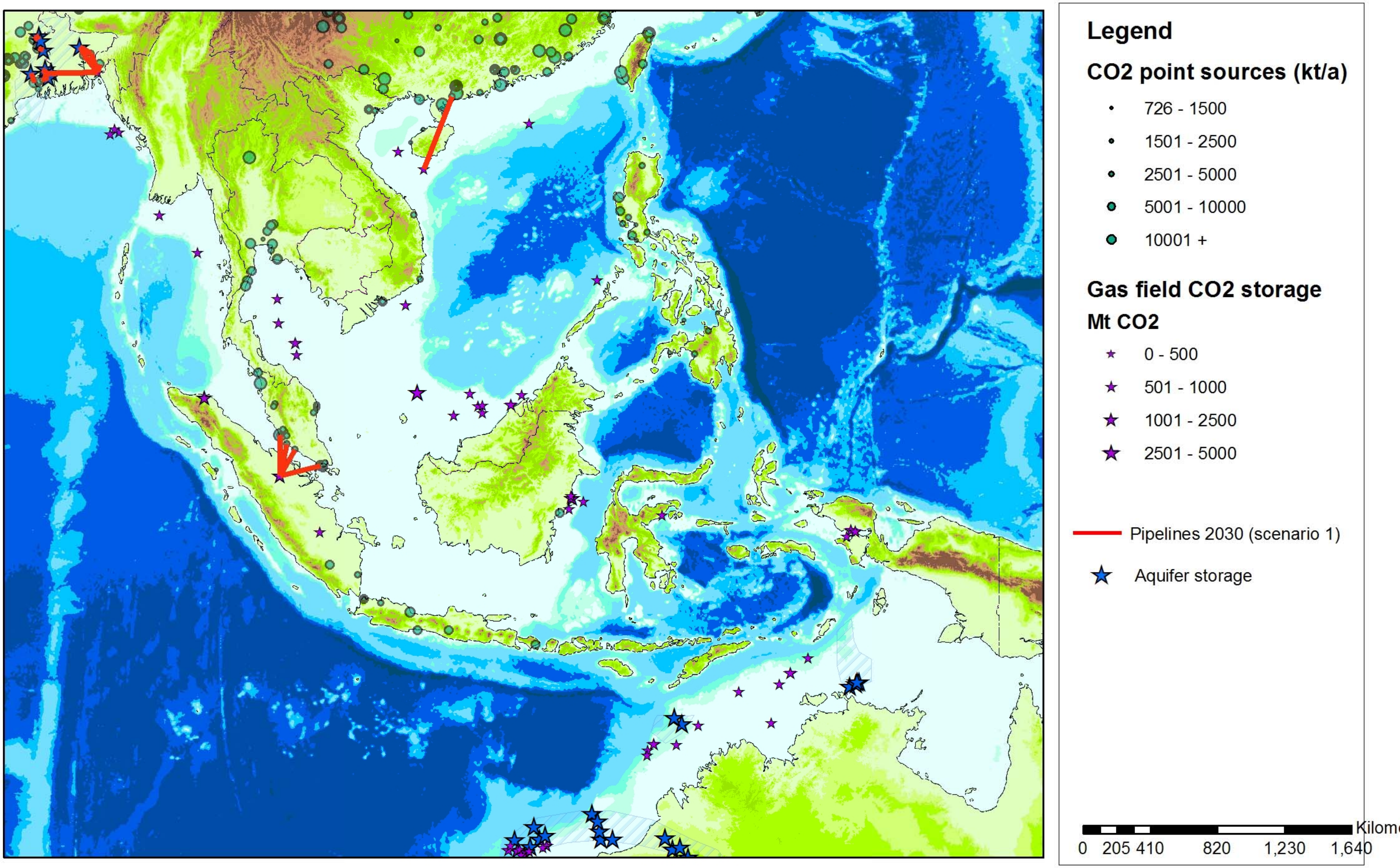

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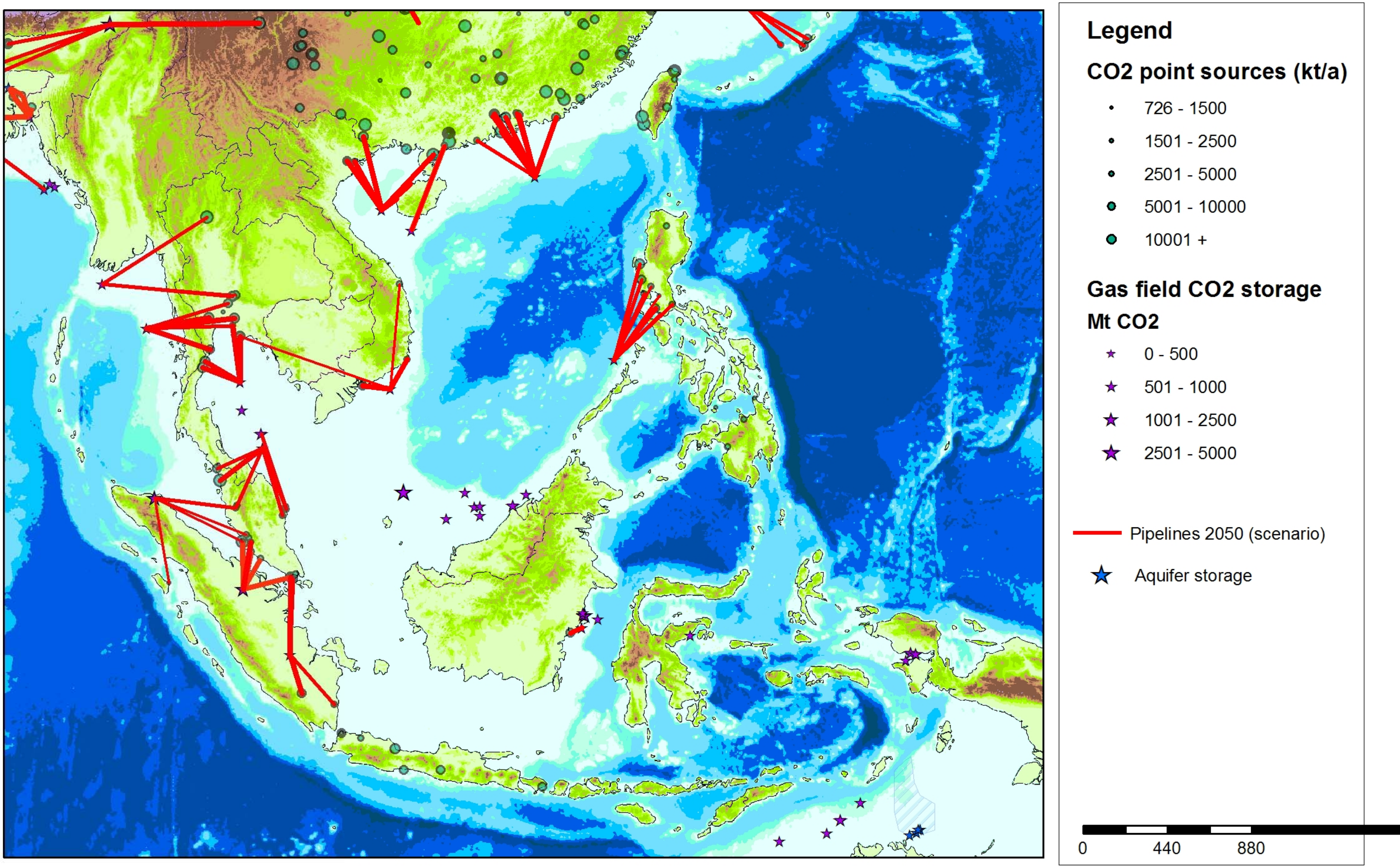

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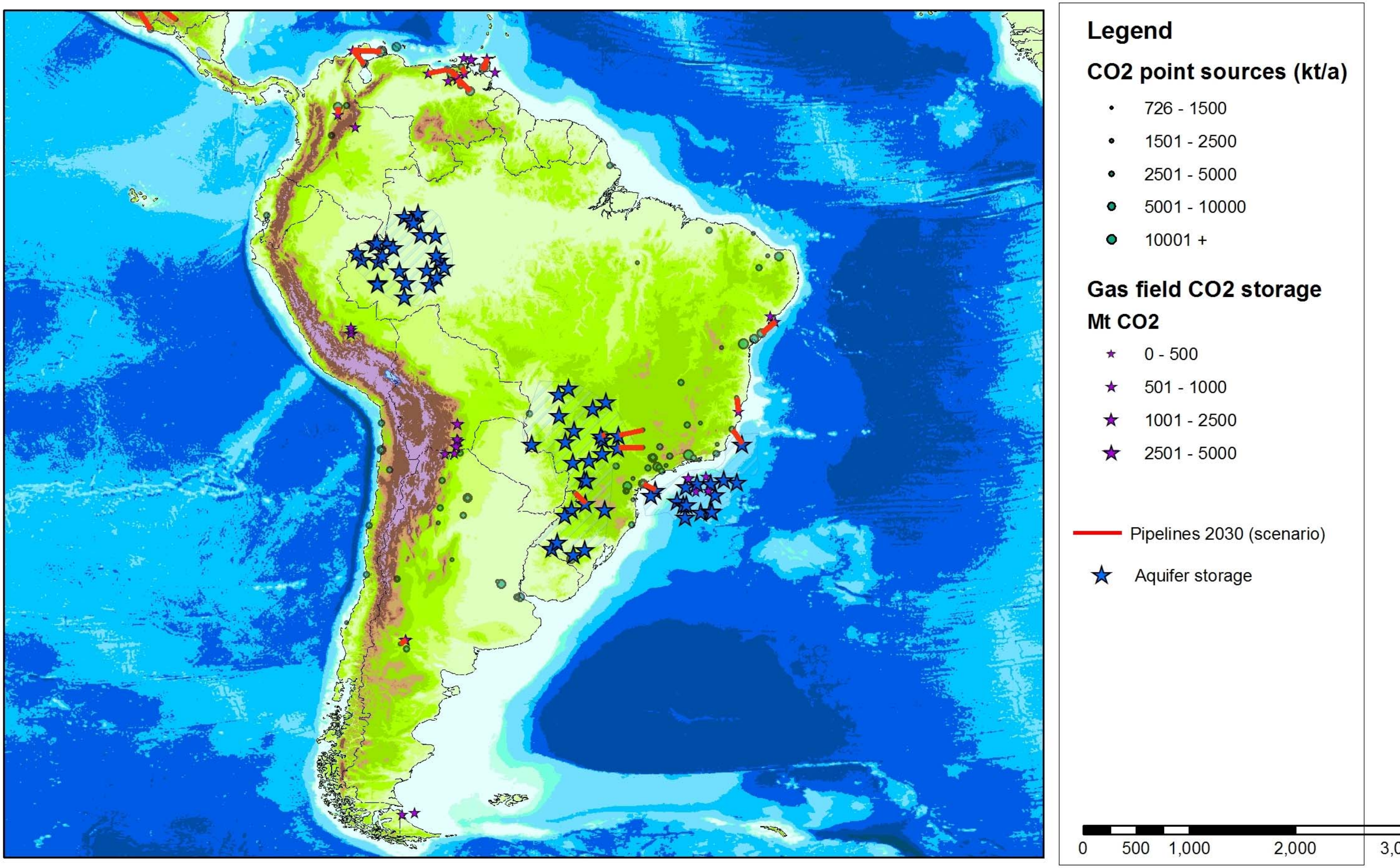

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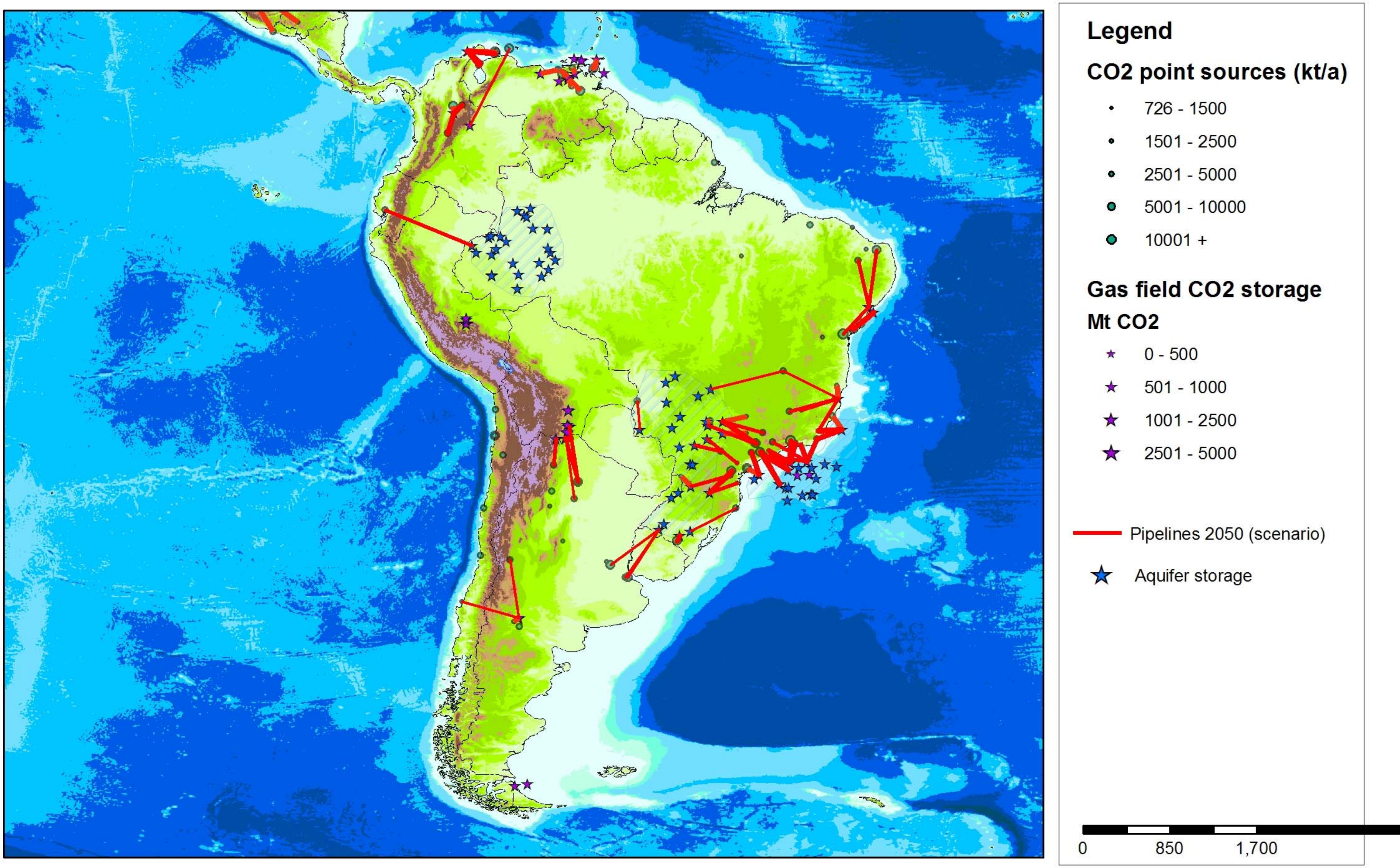

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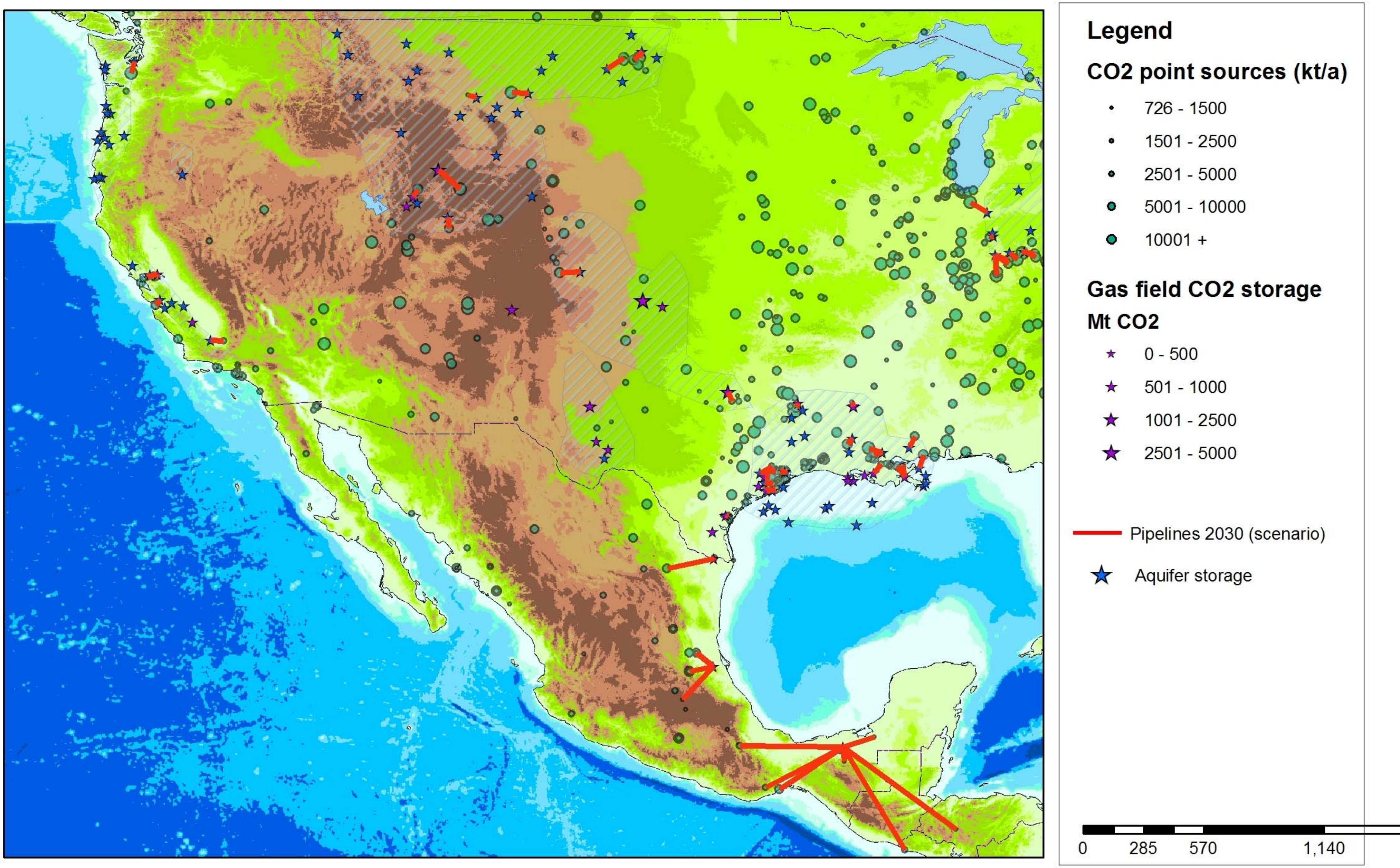

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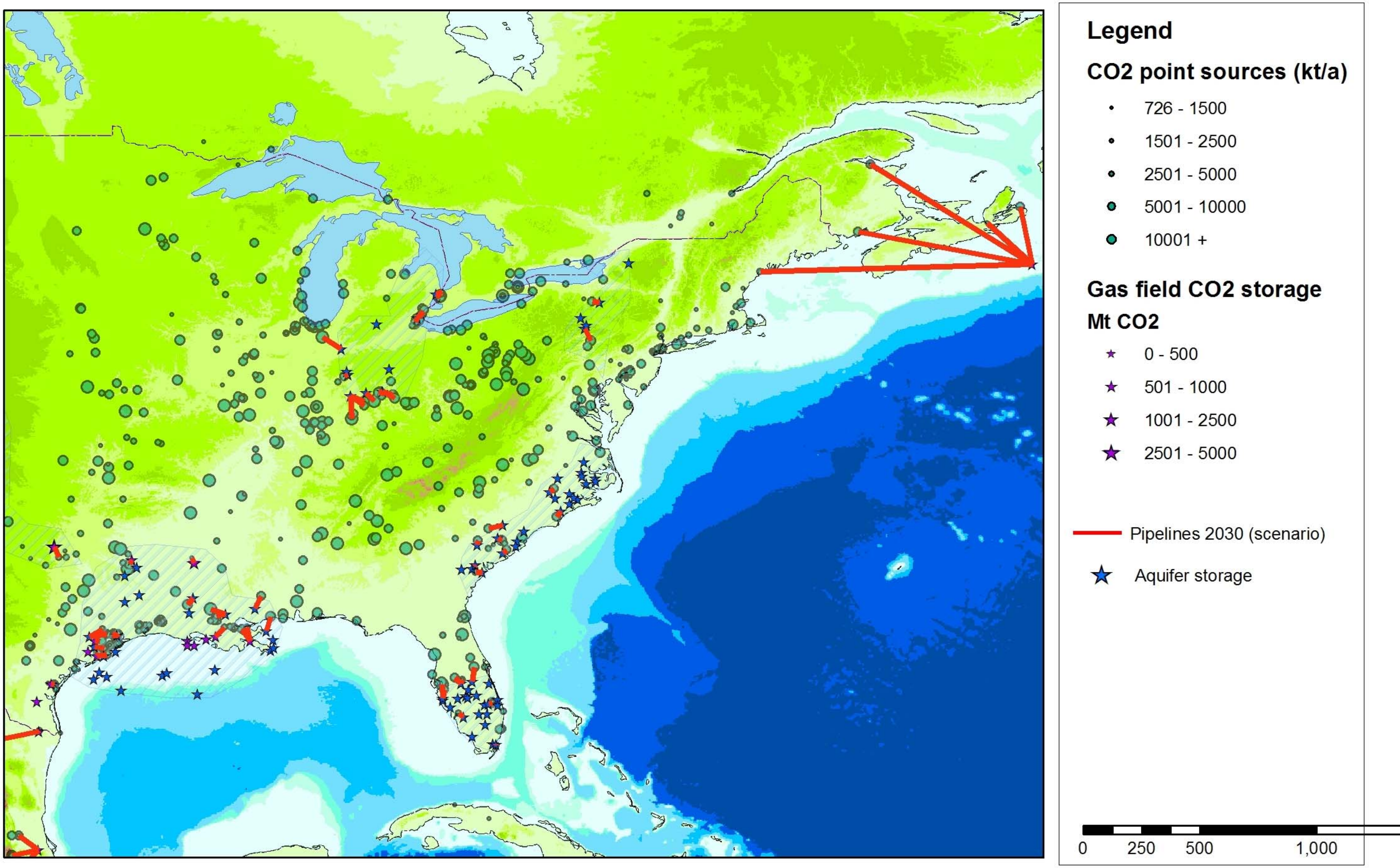

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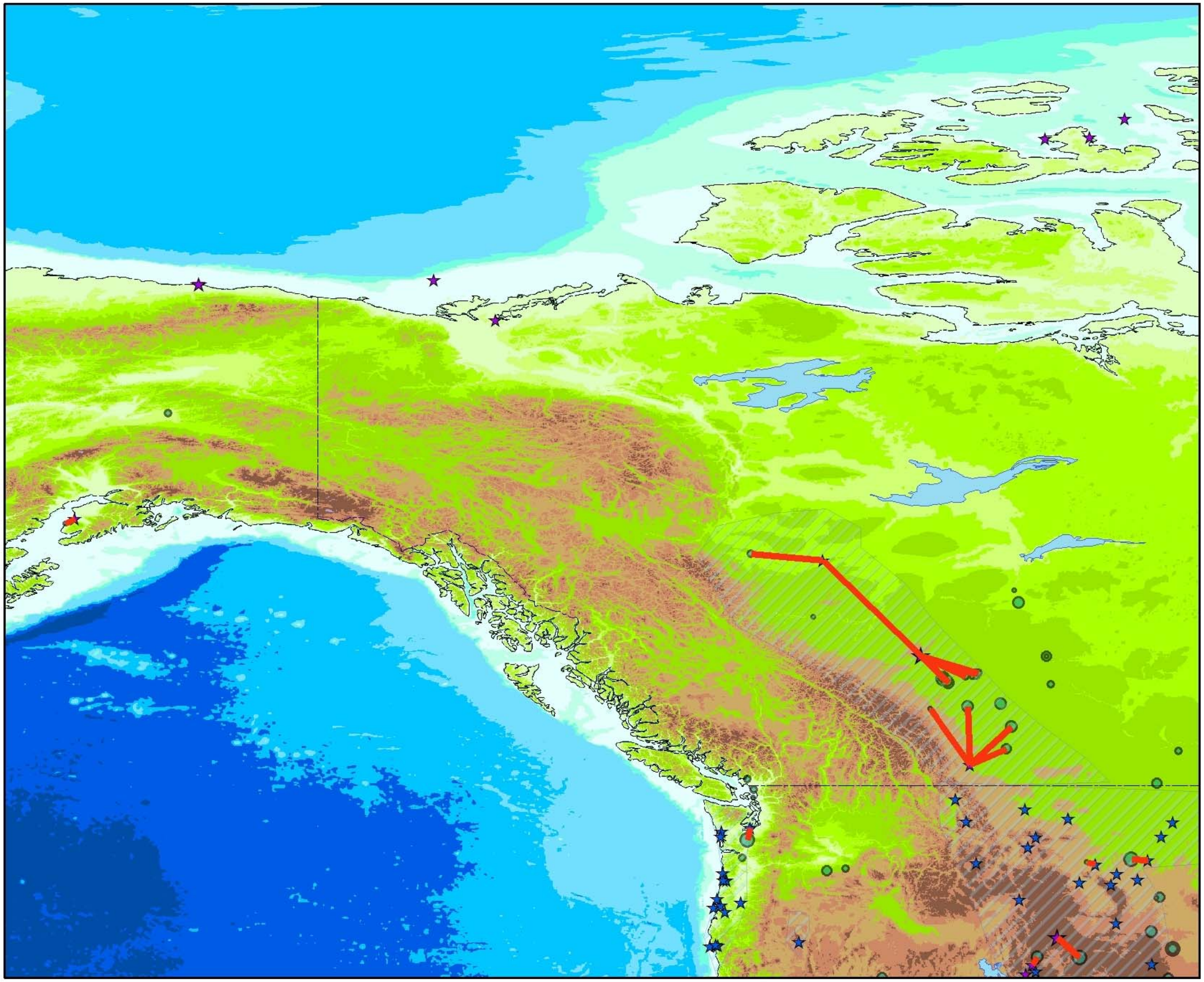

Legend

CO2 point sources (kt/a)

- 726 - 1500
- 1501 - 2500
- 2501 - 5000
- 5001 - 10000
- 10001 +

Gas field CO2 storage

Mt CO2

- 0 - 500
- 501 - 1000
- 1001 - 2500
- 2501 - 5000

Pipelines 2030 (scenario)

Aquifer storage

0 390 780 1,560

A map of networks to meet blue map CCS demand in 2050