

# 4 Transport of CO<sub>2</sub>

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## Executive Summary

Transport is that stage of carbon capture and storage that links sources and storage sites. The beginning and end of ‘transport’ may be defined administratively. ‘Transport’ is covered by the regulatory framework concerned for public safety that governs pipelines and shipping. In the context of long-distance movement of large quantities of carbon dioxide, pipeline transport is part of current practice. Pipelines routinely carry large volumes of natural gas, oil, condensate and water over distances of thousands of kilometres, both on land and in the sea. Pipelines are laid in deserts, mountain ranges, heavily-populated areas, farmland and the open range, in the Arctic and sub-Arctic, and in seas and oceans up to 2200 m deep.

Carbon dioxide pipelines are not new: they now extend over more than 2500 km in the western USA, where they carry 50 Mt yr<sup>-1</sup> of carbon dioxide from natural sources to enhanced oil recovery projects in the west Texas and elsewhere. The carbon dioxide stream ought preferably to be dry and free of hydrogen sulphide, because corrosion is then minimal, and it would be desirable to establish a minimum specification for ‘pipeline quality’ carbon dioxide. However, it would be possible to design a corrosion-resistant pipeline that would operate safely with a gas that contained water, hydrogen sulphide and other contaminants. Pipeline transport of carbon dioxide through populated areas requires attention be paid to design factors, to overpressure protection, and to leak detection. There is no indication that the problems for carbon dioxide pipelines are any more challenging than those set by hydrocarbon pipelines in similar areas, or that they cannot be resolved.

Liquefied natural gas and petroleum gases such as propane and butane are routinely transported by marine tankers; this trade already takes place on a very large scale. Carbon dioxide is transported in the same way, but on a small scale because of limited demand. The properties of liquefied carbon dioxide are not greatly different from those of liquefied petroleum gases, and the technology can be scaled up to large carbon dioxide carriers. A design study discussed later has estimated costs for marine transport of 1 Mt yr<sup>-1</sup> by one 22,000 m<sup>3</sup> marine tanker over a distance of 1100 km, along with the associated liquefaction, loading and unloading systems.

Liquefied gas can also be carried by rail tank and road tankers, but it is unlikely that they be considered attractive options for large-scale carbon dioxide capture and storage projects.

#### 4.1 Introduction

CO<sub>2</sub> is transported in three states: gas, liquid and solid. Commercial-scale transport uses tanks, pipelines and ships for gaseous and liquid carbon dioxide.

Gas transported at close to atmospheric pressure occupies such a large volume that very large facilities are needed. Gas occupies less volume if it is compressed, and compressed gas is transported by pipeline. Volume can be further reduced by liquefaction, solidification or hydration. Liquefaction is an established technology for gas transport by ship as LPG (liquefied petroleum gas) and LNG (liquefied natural gas). This existing technology and experience can be transferred to liquid CO<sub>2</sub> transport. Solidification needs much more energy compared with other options, and is inferior from a cost and energy viewpoint. Each of the commercially viable technologies is currently used to transport carbon dioxide.

Research and development on a natural gas hydrate carrying system intended to replace LNG systems is in progress, and the results might be applied to CO<sub>2</sub> ship transport in the future. In pipeline transportation, the volume is reduced by transporting at a high pressure: this is routinely done in gas pipelines, where operating pressures are between 10 and 80 MPa.

A transportation infrastructure that carries carbon dioxide in large enough quantities to make a significant contribution to climate change mitigation will require a large network of pipelines. As growth continues it may become more difficult to secure rights-of-way for the pipelines, particularly in highly populated zones that produce large amounts of carbon dioxide. Existing experience has been in zones with low population densities, and safety issues will become more complex in populated areas.

The most economical carbon dioxide capture systems appear to favour CO<sub>2</sub> capture, first, from pure stream sources such as hydrogen reformers and chemical plants, and then from centralized power and synfuel plants: Chapter 2 discusses this issue in detail. The producers of natural gas speak of ‘stranded’ reserves from which transport to market is uneconomical. A movement towards a decentralized power supply grid may make CO<sub>2</sub> capture and transport much more costly, and it is easy to envision stranded CO<sub>2</sub> at sites where capture is uneconomic.

A regulatory framework will need to emerge for the low-greenhouse-gas-emissions power industry of the future to guide investment decisions. Future power plant owners may find the carbon dioxide transport component one of the leading issues in their decision-making.

## 4.2 Pipeline systems

### 4.2.1 Pipeline transportation systems

CO<sub>2</sub> pipeline operators have established minimum specifications for composition. Annex 1 to this chapter gives an example from the Canyon Reef project (Section 4.2.2.1). This specification is for gas for an enhanced oil recovery project, and parts of it would not necessarily apply to a CO<sub>2</sub> storage project. A low nitrogen content is important for EOR, but would not be so significant for CCS. A CO<sub>2</sub> pipeline through populated areas might have a lower specified maximum H<sub>2</sub>S content.

Dry carbon dioxide does not corrode the carbon-manganese steels generally used for pipelines, as long as the relative humidity is less than 60% (see, for example, Rogers and Mayhew, 1980); this conclusion continues to apply in the presence of N<sub>2</sub>, NO<sub>x</sub> and SO<sub>x</sub> contaminants. Seiersten (2001) wrote:

The corrosion rate of carbon steel in dry supercritical CO<sub>2</sub> is low. For AISI 1080 values around 0.01 mm yr<sup>-1</sup> have been measured at 90–120 bar and 160°C–180°C for 200 days. Short-term tests confirm this. In a test conducted at 3°C and 22°C at 140 bar CO<sub>2</sub>, and 800 to 1000 ppm H<sub>2</sub>S, the corrosion rate for X-60 carbon steel was measured at less than 0.5 µm yr<sup>-1</sup> [0.0005 mm yr<sup>-1</sup>]. Field experience also indicates very few problems with transportation of high-pressure dry CO<sub>2</sub> in carbon steel pipelines. During 12 years, the corrosion rate in an operating pipeline amounts to 0.25–2.5 µm yr<sup>-1</sup> [0.00025 to 0.0025 mm yr<sup>-1</sup>].

The water solubility limit in high-pressure CO<sub>2</sub> (500 bar) is 5000 ppm at 75°C and 2000 ppm at 30°C. Methane lowers the solubility limit, and H<sub>2</sub>S, O<sub>2</sub> and N<sub>2</sub> may have the same effect.

Corrosion rates are much higher if free water is present; hydrates might also form. Seiersten (2001) measured a corrosion rate of 0.7 mm yr<sup>-1</sup> corrosion rate in 150 to 300 hours exposure at 40°C in water equilibrated with CO<sub>2</sub> at 95 bar, and higher rates at lower pressures. She found little difference between carbon-manganese steel (American Petroleum Institute grade X65) and 0.5 chromium corrosion-resistant alloy. It is unlikely to be practicable to transport wet CO<sub>2</sub> in low-alloy carbon steel pipelines because of this high corrosion rate. If the CO<sub>2</sub> cannot be dried, it may be

necessary to build the pipeline of a corrosion-resistant alloy ('stainless steel'). This is an established technology. However the cost of steel has greatly increased recently and this may not be economical.

**Box 4.1.** *Specimen CO<sub>2</sub> quality specifications*

The Product delivered by Seller or Seller's representative to Buyer at the Canyon Reef Carriers Delivery Meter shall meet the following specifications, which herein are collectively called 'Quality Specifications':

- (a) Carbon Dioxide. Product shall contain at least ninety-five mole percent (95%) of Carbon Dioxide as measured at the SACROC delivery meter.
- (b) Water. Product shall contain no free water, and shall not contain more than  $4.8 \times 10^{-4}$  kg m<sup>-3</sup> in the vapour phase.
- (c) Hydrogen Sulphide. Product shall not contain more than fifteen hundred (1500) parts per million, by weight, of hydrogen sulphide.
- (d) Total Sulphur. Product shall not contain more than fourteen hundred and fifty (1450) parts per million, by weight, of total sulphur.
- (e) Temperature. Product shall not exceed a temperature of 48.9 °C.
- (f) Nitrogen. Product shall not contain more than four mole percent (4%) of nitrogen.
- (g) Hydrocarbons. Product shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed -28.9 °C.
- (h) Oxygen. Product shall not contain more than ten (10) parts per million, by weight, of oxygen.
- (i) Glycol. Product shall not contain more than  $4 \times 10^{-5}$  L m<sup>-3</sup> of glycol and at no time shall such glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

Once the CO<sub>2</sub> has been dried and meets the transportation criteria, the CO<sub>2</sub> is measured and transported to the final use site. All the pipelines have state-of-the-art metering systems that accurately account for sales and deliveries on to and out of each line, and SCADA (Supervisory Control and Data Acquisition) systems for measuring pressure drops, and redundancies built in to allow for emergencies. In the USA, these pipelines are governed by Department of Transportation regulations (See 49 CFR 195). Movement of CO<sub>2</sub> is best accomplished under high pressure: the choice of operating pressure is discussed in an example below, and the reader is referred to *Appendix I* for a discussion of the physical properties of CO<sub>2</sub>.

#### 4.2.2 Existing experience

Table 4.1 lists existing long-distance CO<sub>2</sub> pipelines. Most of the projects listed below are described in greater detail in a report by the UK Department of Trade and Industry (2002). While there are CO<sub>2</sub> pipelines outside the USA, the Permian Basin contains over 90% of the active CO<sub>2</sub> floods in the world (O&GJ, April 15, 2002, EOR Survey). Since then, well over 1600 km of new CO<sub>2</sub> pipelines has been built to service enhanced oil recovery (EOR) in west Texas and nearby states.

**Table 4.1.** Existing long -distance CO<sub>2</sub> pipelines (Gale and Davison, 2002) and CO<sub>2</sub> pipelines in North America. Reproduced by courtesy of Oil and Gas Journal.

**Figure 4.1.** CO<sub>2</sub> pipelines in North America. Reproduced by courtesy of Oil and Gas Journal.

#### 4.2.2.1 Canyon Reef

The first large CO<sub>2</sub> pipeline in the USA was the Canyon Reef Carriers, built in 1970 by the SACROC Unit in Scurry County, Texas. Its 352 km moved 12,000 tonnes of anthropogenically produced CO<sub>2</sub> daily (4.4 Mt yr<sup>-1</sup>) from Shell Oil Company gas processing plants in the Texas Val Verde basin.

#### 4.2.2.2 Bravo Dome Pipeline

Oxy Permian constructed this 508 mm (20-inch) line connecting the Bravo Dome CO<sub>2</sub> field with other major pipelines. It is capable of carrying 7.3 Mt yr<sup>-1</sup> and now is operated by Kinder Morgan.

#### 4.2.2.3 Cortez Pipeline

Built in 1982 to supply CO<sub>2</sub> from the McElmo Dome in S.E. Colorado, the 762 mm (30-inch), 803 km pipeline carries approximately 20 Mt CO<sub>2</sub> yr<sup>-1</sup> to the CO<sub>2</sub> hub at Denver City, Texas. The line starts near Cortez, Colorado, and crosses the Rocky Mountains, where it interconnects with other CO<sub>2</sub> lines. In the present context, recall that one 1000 MW coal-fired power station produces about 7 Mt CO<sub>2</sub> yr<sup>-1</sup>, and so one Cortez pipeline could handle the emissions of three of those stations.

The Cortez Pipeline passes through two built-up areas, Placitas, New Mexico (30 km north of Albuquerque, New Mexico) and Edgewood/Moriarty, New Mexico (40 km east of Albuquerque). The line is buried at least 1 m deep and is marked within its right of way. Near houses and built-up areas it is marked more frequently to ensure the residents are aware of the pipeline locations. The entire pipeline is patrolled by air every two weeks, and in built-up areas is frequently patrolled by employees in company vehicles. The public education programme includes the mailing of a brochure describing CO<sub>2</sub>, signs of a leak and where to report a suspected leak, together with information about the operator and the “one-call” centre.

#### 4.2.2.4 Sheep Mountain Pipeline

BP Oil constructed this 610 mm (24-inch) 772 km line capable of carrying 9.2 Mt CO<sub>2</sub> yr<sup>-1</sup> from another naturally occurring source in southeast Colorado. It connects to the Bravo Dome line and into the other major carriers at Denver City and now is operated by Kinder Morgan..

#### 4.2.2.5 Weyburn Pipeline

This 330 km 356 mm and 305 mm diameter system carries more than 5000 tonne day<sup>-1</sup> (1.8 Mt yr<sup>-1</sup>) of CO<sub>2</sub> from the Great Plains Synfuels Plant near Beulah, North Dakota to the Weyburn EOR project in Saskatchewan. The composition of the gas carried by the pipeline is typically CO<sub>2</sub> 96%, H<sub>2</sub>S 0.9%, CH<sub>4</sub> 0.7%, C<sub>2</sub>+ hydrocarbons 2.3%, CO 0.1%, N<sub>2</sub> less than 300 ppm, O<sub>2</sub> less than 50 ppm and H<sub>2</sub>O less than 20 ppm (UK Department of Trade and Industry, 2002). The delivery pressure at Weyburn is 15.2 MPa. There are no intermediate compressor stations. The amount allocated to build the pipeline was M\$ 110 (0.33 M\$ km<sup>-1</sup>) in 1997.

### 4.2.3 Design

The physical, environmental and social factors that determine the design of a pipeline are summarized in a design basis, which then forms the input for the conceptual design. This includes a system definition for the preliminary route and design aspects for cost-estimating and concept-definition purposes. It is also necessary to consider the process data defining the physical characteristics of product mixture transported, the optimal sizing and pressures for the pipeline, and the mechanical design, such as operating, valves, pumps, compressors, seals, etc. The topography of

the pipeline right-of-way must be examined. Topography may include mountains, deserts, river and stream crossings, and for offshore pipelines, the differing challenges of very deep or shallow water, and uneven seabed. It is also important to include geotechnical considerations. For example, is this pipeline to be constructed on thin soil overlaying granite? The local environmental data need to be included, as well as the annual variation in temperature during operation and during construction, potentially unstable slopes, frost heave and seismic activity. Also included are water depth, sea currents, permafrost, ice gouging in Arctic seas, biological growth, aquifers, and other environmental considerations such as protected habitats. The next set of challenges is how the pipeline will accommodate existing and future infrastructure – road, rail, pipeline crossings, military/governmental restrictions and the possible impact of other activities – as well as shipping lanes, rural or urban settings, fishing restrictions, and conflicting uses such as dredging. Finally, this integrated study will serve as the basis for a safety review.

### *Conceptual Design*

The conceptual design includes the following components:

- Mechanical design: follows standard procedures, described in detail in (Palmer et al., 2004).
- Stability design: standard methods and software are used to perform stability calculations, offshore (Veritec, 1988) or onshore, though the offshore methods have been questioned. New guidelines for stability will be published in 2005 by Det Norske Veritas and will be designated DNV-RP-F109 On-Bottom Stability
- Protection against corrosion: a well-understood subject of which the application to CO<sub>2</sub> pipelines is described below.
- Trenching and backfilling: onshore lines are usually buried to depth of 1 m. Offshore lines are almost always buried in shallow water. In deeper water pipelines narrower than 400 mm are trenching and sometimes buried to protect them against damage by fishing gear.
- CO<sub>2</sub> pipelines may be more subject to longitudinal running fracture than hydrocarbon gas pipelines. Fracture arresters are installed at intervals of about 500 m.

West (1974) describes the design of the SACROC CO<sub>2</sub> pipeline (Section 4.2.2.1 above). The transportation options examined were:

- (i) a low-pressure CO<sub>2</sub> gas pipeline operating at a maximum pressure of 4.8 MPa;
- (ii) a high-pressure CO<sub>2</sub> gas pipeline operating at a minimum pressure of 9.6 MPa, so that the gas would remain in a dense phase state at all temperatures;
- (iii) a refrigerated liquid CO<sub>2</sub> pipeline;
- (iv) road tank trucks;
- (v) rail tankers, possibly in combination with road tank trucks.

The tank truck and rail options cost more than twice as much as a pipeline. The refrigerated pipeline was rejected because of cost and technical difficulties with liquefaction. The dense phase (Option ii) was 20% cheaper than a low-pressure CO<sub>2</sub> gas pipeline (Option i). The intermediate 4.8 to 9.6 MPa pressure range was avoided so that two-phase flow would not occur. An added advantage of dense-phase transport was that high delivery pressures were required for CO<sub>2</sub> injection.

The final design conforms to the ANSI B31.8 code for gas pipelines and to the DOT regulations applicable at the time. The main 290 km section is 406.4 mm (16 inch) outside diameter and 9.53 mm wall thickness made from grade X65 pipe (specified minimum yield stress of 448 MPa). A shorter 60 km section is 323.85 mm (12.75 inch) outside diameter, 8.74 mm wall thickness, grade X65. Tests showed that dry CO<sub>2</sub> would not corrode the pipeline steel; 304L corrosion-resistant alloy was used for short sections upstream of the glycol dehydrator. The line is buried to a minimum of 0.9 m, and any point on the line is within 16 km of a block valve.

There are six compressor stations, totalling 60 MW, including a station at the SACROC delivery point. The compressor stations are not equally spaced, and the longest distance between two stations is about 160 km. This is consistent with general practice, but some long pipelines have 400 km or more between compressor stations.

Significant nitrogen and oxygen components in CO<sub>2</sub> would shift the boundary of the two-phase region towards higher pressures, and would require a higher operating pressure to avoid two-phase flow.

#### **4.2.4 Construction of land pipelines**

Construction planning can begin either before or after rights of way are secured, but a decision to construct will not come before a legal right to construct a pipeline is secured and all governmental regulations met. Onshore and underwater CO<sub>2</sub> pipelines are constructed in the same way as hydrocarbon pipelines, and for both there is an established and well-understood base of engineering experience. Subsection 4.2.5 describes underwater construction.

The construction phases of a land pipeline are outlined below. Some of the operations can take place concurrently.

Environmental and social factors may influence the season of the year in which construction takes place. The land is cleared and the trench excavated. The longest lead items come first: urban areas, river and road crossings. Pipe is received into the pipe yard and welded into double joints (24 m long); transported to staging areas for placement along the pipe route, welded, tested, coated and wrapped, and then lowered into the trench. A hydrostatic test is carried out, and the line is dried. The trench is then backfilled, and the land and the vegetation restored.

#### **4.2.5 Underwater pipelines**

Most underwater pipelines are constructed by the lay-barge method, in which 12 or 24 m lengths of pipe are brought to a dynamically positioned or anchored barge, and welded one by one to the end of the pipeline. The barge moves slowly forward, and the pipeline leaves the barge over the stern, and passes first over a support structure ('stinger') and then down through the water in a suspended span, until it reaches the seabed. Some lines up to 450 mm diameter are constructed by the reel method, in which the pipeline is welded together onshore, wound onto a reel on a ship, and then unwound from the reel into its final position. Some short lines and lines for shore crossings in shallow water are constructed by various tow and pull methods, in which the line is welded together onshore and then pulled into its final location.

If the design requires that the pipeline be trenched, that is usually done after it has been laid on the seabed, by a jetting sled, a plough or a mechanical cutting device that is pulled along the line. On the other hand, in shore crossings and in very shallow water the trench is often excavated before the pipeline is laid, and that is done by dredgers, backhoes or draglines in soft sediments, or in rock by blasting followed by clamshell excavators. Many shore crossings are drilled horizontally from the shore; this procedure eliminates many uncertainties associated with the surf zone, and reduces the environmental impact of construction.

Underwater connections are made by various kinds of mechanical connection systems, by hyperbaric welding (in air under the local hydrostatic pressure) or by lifting the pipe ends above the surface, welding them together and lowering the connected line to the bottom.



These technologies are established and understood (Palmer and King, 2004). Underwater pipelines up to 1422 mm in diameter have been constructed in many different environments, and pipelines have been laid in depths up to 2200 m. Figure 4.2 plots the diameters and maximum depths of major deepwater pipelines constructed up to 2004. The difficulty of construction is roughly proportional to the depth multiplied by the diameter, and the maximum value of that product has multiplied fourfold since 1980. Still larger and deeper pipelines are technically feasible with today's technology.

**Figure 4.2.** Pipelines in deep water.

#### **4.2.6 Operations**

Operational aspects of pipelines are divided into three areas: daily operations, maintenance, and health, safety and environment. Operations of a CO<sub>2</sub> pipeline in the USA, for instance, must follow federal operations guidelines (49 CFR 195). Overall operational considerations include training, inspections, safety integration, signs and pipeline markers, public education, damage prevention programmes, communication, facility security and leak detection. Pipelines outside the USA generally have similar regulatory operational requirements.

Personnel form a central part of operations and must be qualified. Personnel are required to be continuously trained and updated on safety procedures, including safety procedures that apply to contractors working on or near the pipeline, as well as to the public.

Operations include daily maintenance, scheduled planning and policies for inspecting, maintaining and repairing all equipment on the line and the pipeline itself, as well as supporting the line and pipeline. This equipment and support includes valves, compressors, pumps, tanks, rights of way, public signs and line markers as well as periodic pipeline flyovers.

Long-distance pipelines are instrumented at intervals so that the flow can be monitored. The monitoring points, compressor stations and block valves are tied back to a central operations centre. Computers control much of the operation, and manual intervention is necessary only in unusual upsets or emergency conditions. The system has inbuilt redundancies to prevent loss of operational capability if a component fails.

Pipelines are cleaned and inspected by 'pigs', piston-like devices driven along the line by the gas pressure. Pigs have reached a high level of sophistication, and can measure internal corrosion, mechanical deformation, external corrosion, the precise position of the line, and the development of spans in underwater lines. Further functionality will develop as pig technology evolves, and there is no reason why pigs used for hydrocarbon pipelines should not be used for carbon dioxide.

Pipelines are also monitored externally. Land pipelines are inspected from the air, at intervals agreed between the operator and the regulatory authorities. Inspection from the air detects unauthorized excavation or construction before damage occurs. Currently, underwater pipelines are monitored by remotely operated vehicles, small unmanned submersibles that move along the line and make video records, and in the future, by autonomous underwater vehicles that do not need to be connected to a mother ship by a cable. Some pipelines have independent leak detection systems that find leaks acoustically or by measuring chemical releases, or by picking up pressure changes or small changes in mass balance. This technology is available and routine.

### 4.3 Ships for CO<sub>2</sub> transportation

#### 4.3.1 *Marine transportation system*

Carbon dioxide is continuously captured at the plant on land, but the cycle of ship transport is discrete, and so a marine transportation system includes temporary storage on land and a loading facility. The capacity, service speed, number of ships and shipping schedule will be planned, taking into consideration, the capture rate of CO<sub>2</sub>, transport distance, and social and technical restrictions. This issue is, of course, not specific to the case of CO<sub>2</sub> transport; CO<sub>2</sub> transportation by ship has a number of similarities to liquefied petroleum gas (LPG) transportation by ship.

What happens at the delivery point depends on the CO<sub>2</sub> storage system. If the delivery point is onshore, the CO<sub>2</sub> is unloaded from the ships into temporary storage tanks. If the delivery point is offshore – as in the ocean storage option – ships might unload to a platform, to a floating storage facility (similar to a floating production and storage facility routinely applied to offshore petroleum production), to a single-buoy mooring or directly to a storage system.

#### 4.3.2 *Existing experience*

The use of ships for transporting CO<sub>2</sub> across the sea is today in an embryonic stage. Worldwide there are only four small ships used for this purpose. These ships transport liquefied food-grade CO<sub>2</sub> from large point sources of concentrated carbon dioxide such as ammonia plants in northern Europe to coastal distribution terminals in the consuming regions. From these distribution terminals CO<sub>2</sub> is transported to the customers either by tanker trucks or in pressurized cylinders. Design work is ongoing in Norway and Japan for larger CO<sub>2</sub> ships and their associated liquefaction and intermediate storage facilities.

#### 4.3.3 *Design*

For the design of hull and tank structure of liquid gas transport ships, such as LPG carriers and LNG carriers, the International Maritime Organization adopted the International Gas Carrier Code in order to prevent the significant secondary damage from accidental damage to ships. CO<sub>2</sub> tankers are designed and constructed under this code.

There are three types of tank structure for liquid gas transport ships: pressure type, low temperature type and semi-refrigerated type. The pressure type is designed to prevent the cargo gas from boiling under ambient air conditions. On the other hand, the low temperature type is designed to operate at a sufficiently low temperature to keep cargo gas as a liquid under the atmospheric pressure. Most small gas carriers are pressure type, and large LPG and LNG carriers are of the low temperature type. The low temperature type is suitable for mass transport because the tank size restriction is not severe. The semi-refrigerated type, including the existing CO<sub>2</sub> carriers, is designed taking into consideration the combined conditions of temperature and pressure necessary for cargo gas to be kept as a liquid. Some tankers such as semi-refrigerated LPG carriers are designed for applicability to the range of cargo conditions between normal temperature/high pressure and low temperature/atmospheric pressure.

*Appendix I* to this report includes the CO<sub>2</sub> phase diagram. At atmospheric pressure, CO<sub>2</sub> is in gas or solid phase, depending on the temperature. Lowering the temperature at atmospheric pressure cannot by itself cause CO<sub>2</sub> to liquefy, but only to make so-called ‘dry ice’ or solid CO<sub>2</sub>. Liquid CO<sub>2</sub> can only exist at a combination of low temperature and pressures well above atmospheric pressure. Hence, a CO<sub>2</sub> cargo tank should be of the pressure-type or semi-refrigerated. The semi-refrigerated type is preferred by ship designers, and the design point of the cargo tank would be around –54 °C

per 6 bar to  $-50^{\circ}\text{C}$  per 7 bar, which is near the triple point of  $\text{CO}_2$ . In a standard design, semi-refrigerated type LPG carriers operate at a design point of  $-50^{\circ}\text{C}$  and 7 bar, when transporting a volume of  $22,000\text{ m}^3$ .

Carbon dioxide could leak into the atmosphere during transportation. The total loss to the atmosphere from ships is between 3 and 4% per 1000 km, counting both boil-off and exhaust from the ship's engines; both components could be reduced by capture and liquefaction, and recapture onshore would reduce the loss to 1 to 2% per 1000 km.

#### 4.3.4 Construction

Carbon dioxide tankers are constructed using the same technology as existing liquefied gas carriers. The latest LNG carriers reach more than  $200,000\text{ m}^3$  capacity. (Such a vessel could carry 230 kt of liquid  $\text{CO}_2$ .) The same type of yards that today build LPG and LNG ships can carry out the construction of a  $\text{CO}_2$  tanker. The actual building time will be from one to two years, depending on considerations such as the ship's size.

#### 4.3.5 Operation

##### 4.3.5.1 Loading

Liquid  $\text{CO}_2$  is charged from the temporary storage tank to the cargo tank with pumps adapted for high pressure and low temperature  $\text{CO}_2$  service. The cargo tanks are first filled and pressurized with gaseous  $\text{CO}_2$  to prevent contamination by humid air and the formation of dry ice.

##### 4.3.5.2 Transport to the site

Heat transfer from the environment through the wall of the cargo tank will boil  $\text{CO}_2$  and raise the pressure in the tank. It is not dangerous to discharge the  $\text{CO}_2$  boil-off gas together with the exhaust gas from the ship's engines, but doing so does, of course, release  $\text{CO}_2$  to the air. The objective of zero  $\text{CO}_2$  emissions during the process of capture and storage can be achieved by using a refrigeration unit to capture and liquefy boil-off and exhaust  $\text{CO}_2$ .

##### 4.3.5.3 Unloading

Liquid  $\text{CO}_2$  is unloaded at the destination site. The volume occupied by liquid  $\text{CO}_2$  in the cargo tanks is replaced with dry gaseous  $\text{CO}_2$ , so that humid air does not contaminate the tanks. This  $\text{CO}_2$  could be recycled and reliquefied when the tank is refilled.

##### 4.3.5.4 Return to port in ballast, and dry-docking

The  $\text{CO}_2$  tanker will return to the port for the next voyage. When the  $\text{CO}_2$  tanker is in dock for repair or regular inspection, gas  $\text{CO}_2$  in cargo tank should be purged with air for safe working. For the first loading after docking, cargo tanks should be fully dried, purged and filled with  $\text{CO}_2$  gas.

Ships of similar construction with a combination of cooling and pressure are currently operated for carrying other industrial gases.

## 4.4 Risk, safety and monitoring

### 4.4.1 Introduction

There are calculable and perceivable risks for any transportation option. We are not considering perceivable risks because this is beyond the scope of the document. Risks in special cases such as military conflicts and terrorist actions have now been investigated. At least two conferences on pipeline safety and security have taken place, and additional conferences and workshops are planned. However, it is unlikely that these will lead to peer-reviewed journal articles because of the sensitivity of the issue.

Pipelines and marine transportation systems have an established and good safety record. Comparison of CO<sub>2</sub> systems with these existing systems for long-distance pipeline transportation of gas and oil or with marine transportation of oil, should be comparable in terms of failure and accident rates. For the existing transport system these incidents seem to be perceived by the broad community as acceptable in spite of occasional serious pollution incidents such as the *Exxon Valdes* and *Torrey Canyon* disasters, see van Bernem and Lubbe, 1997. Because the *consequences* of CO<sub>2</sub> pipeline accidents potentially are of significant concern, stricter regulations for CO<sub>2</sub> pipelines than those for natural gas pipelines currently are in force in the USA.

### 4.4.2 Land pipelines

Land pipelines are built to defined standards and are subject to regulatory approval. This sometimes includes independent design reviews. Their routes are frequently the subject of public inquiries. The process of securing regulatory approval generally includes approval of a safety plan, of detailed monitoring and inspection procedures and of emergency response plans. In densely populated areas the process of planning, licensing and building new pipelines may be difficult and time-consuming. In some places it may be possible to convert existing hydrocarbon pipelines into CO<sub>2</sub> pipelines.

Pipelines in operation are monitored internally by pigs (internal pipeline inspection devices) and externally by corrosion monitoring and leak detection systems. Monitoring is also done by patrols on foot and by aircraft.

The incidence of failure is relatively small. Guijt (2004) and the European Gas Pipeline Incident Data Group (2002) show that the incidence of failure has markedly decreased. Guijt quotes an incident rate of almost 0.0010 km<sup>-1</sup> year<sup>-1</sup> in 1972 falling to below 0.0002 km<sup>-1</sup> year<sup>-1</sup> in 2002. Most of the incidents refer to very small pipelines, less than 100 mm in diameter, principally applied to gas distribution systems. The failure incidence for 500 mm and larger pipelines is very much lower, below 0.00005 km<sup>-1</sup> year<sup>-1</sup>. These figures include all unintentional releases outside the limits of facilities (such as compressor stations) originating from pipelines whose design pressures are greater than 1.5 MPa. They cover many kinds of incidents, not all of them serious, and there is substantial variation between pipelines, reflecting factors such as system age and inspection frequency.

The corresponding incident figures for western European oil pipelines have been published by CONCAWE (2002). In 1997-2001 the incident frequency was 0.0003 km<sup>-1</sup> yr<sup>-1</sup>. The corresponding figure for US onshore gas pipelines was 0.00011 km<sup>-1</sup> yr<sup>-1</sup> for the 1986-2002 period, defining an incident as an event that released gas and caused death, inpatient hospitalization or property loss of US\$ 50,000: this difference in reporting threshold is thought to account for the difference between European and US statistics (Guijt, 2004).

Lelieveld et al. (2005) examined leakage in 2400 km of the Russian natural gas pipeline system, including compressor stations, valves and machine halls, and concluded that ‘...overall, the leakage from Russian natural gas transport systems is about 1.4% (with a range of 1.0-2.5%), which is comparable with the amount lost from pipelines in the United States ( $1.5 \pm 0.5\%$ )’. Those numbers refer to total leakage, not to leakage per kilometre.

Gale and Davison (2002) quote incident statistics for CO<sub>2</sub> pipelines in the USA. In the 1990-2002 period there were 10 incidents, with property damage totalling US\$ 469,000, and no injuries and no fatalities. The incident rate was  $0.00032 \text{ km}^{-1} \text{ yr}^{-1}$ . However, unlike oil and gas, CO<sub>2</sub> does not form flammable or explosive mixtures with air. Existing CO<sub>2</sub> pipelines are mainly in areas of low population density, which would also tend to result in lower average impacts. The reasons for the incidents at CO<sub>2</sub> pipelines were relief valve failure (4 failures), weld/gasket/valve packing failure (3), corrosion (2) and outside force (1). In contrast, the principal cause of incidents for natural gas pipelines is outside force, such as damage by excavator buckets. Penetration by excavators can lead to loss of pipeline fluid and sometimes to fractures that propagate great distances. Preventative measures such as increasing the depth of cover and use of concrete barriers above a pipeline and warning tape can greatly reduce the risk. For example, increasing cover from 1 m to 2 m reduces the damage frequency by a factor of 10 in rural areas and by 3.5 in suburban areas (Guijt, 2004).

Carbon dioxide leaking from a pipeline forms a potential physiological hazard for humans and animals. The consequences of CO<sub>2</sub> incidents can be modelled and assessed on a site-specific basis using standard industrial methods, taking into account local topography, meteorological conditions, population density and other local conditions. A study by Vendrig et al. (2003) has modelled the risks of CO<sub>2</sub> pipelines and booster stations. A property of CO<sub>2</sub> that needs to be considered when selecting a pipeline route is the fact that CO<sub>2</sub> is denser than air and can therefore accumulate to potentially dangerous concentrations in low lying areas. Any leak transfers CO<sub>2</sub> to the atmosphere.

If substantial quantities of impurities, particularly H<sub>2</sub>S, are included in the CO<sub>2</sub>, this could affect the potential impacts of a pipeline leak or rupture. The exposure threshold at which H<sub>2</sub>S is immediately dangerous to life or health, according to the National Institute for Occupational Safety and Health, is 100 ppm, compared to 40,000 ppm for CO<sub>2</sub>.

If CO<sub>2</sub> is transported for significant distances in densely populated regions, the number of people potentially exposed to risks from CO<sub>2</sub> transportation facilities may be greater than the number exposed to potential risks from CO<sub>2</sub> capture and storage facilities. Public concerns about CO<sub>2</sub> transportation may form a significant barrier to large-scale use of CCS. At present most electricity generation or other fuel conversion plants are built close to energy consumers or sources of fuel supply. New plants with CO<sub>2</sub> capture could be built close to CO<sub>2</sub> storage sites, to minimize CO<sub>2</sub> transportation. However, this may necessitate greater transportation of fuels or electricity, which have their own environmental impacts, potential risks and public concerns. A gathering system would be needed if CO<sub>2</sub> were brought from distributed sources to a trunk pipeline, and for some storage options a distribution system would also be needed: these systems would need to be planned and executed with the same regard for risk outlined here.

#### 4.4.3 *Marine pipelines*

Marine pipelines are subject to a similar regulatory regime. The incidence of failure in service is again low. Dragging ships’ anchors causes some failures, but that only occurs in shallow water (less than 50 m). Very rarely do ships sink on to pipelines, or do objects fall on to them. Pipelines of 400 mm diameter and larger have been found to be safe from damage caused by fishing gear, but

smaller pipelines are trenched to protect them. Damage to underwater pipelines was examined in detail at a conference reported on in Morris and Breaux (1995). Palmer and King (2004) examine case studies of marine pipeline failures, and the technologies of trenching and monitoring. Most failures result from human error. Ecological impacts from a CO<sub>2</sub> pipeline accident have yet to be assessed.

Marine pipelines are monitored internally by inspection devices called ‘pigs’ (as described earlier in Section 4.2.5), and externally by regular visual inspection from remotely operated vehicles. Some have independent leak detection systems.

#### 4.4.4 Ships

Ship systems can fail in various ways: through collision, foundering, stranding and fire. Perrow’s book on accidents (1984) includes many thought-provoking case studies. Many of the ships that he refers to were old, badly maintained and crewed by inadequately trained people. However, it is incorrect to think that marine accidents happen only to poorly regulated ‘flag-of-convenience’ ships. Gottschalch and Stadler (1990) share Perrow’s opinion that many marine accidents can be attributed to system failures and human factors, whereas accidents arising as a consequence of purely technical factors are relatively uncommon.

Ship casualties are well summarized by Lloyds Maritime Information Service. Over 22.5 years between 1978 and 2000, there were 41,086 incidents of varying degrees of severity identified, of which 2,129 were classified as ‘serious’ (See Table 4.2).

**Table 4.2.** Statistics on serious incidents, depending on the ship type

Tankers can be seen to have higher standards than ships in general. Stranding is the source of most of the tanker incidents that have led to public concern. It can be controlled by careful navigation along prescribed routes, and by rigorous standards of operation. LNG tankers are potentially dangerous, but are carefully designed and appear to be operated to very high standards. There have been no accidental losses of cargo from LNG ships. The LNG tanker *El Paso Paul Kaiser* ran aground at 17 knots in 1979, and incurred substantial hull damage, but the LNG tanks were not penetrated and no cargo was lost. There is extensive literature on marine transport of liquefied gas, with a strong emphasis on safety, for example, in Ffooks (1993).

Carbon dioxide tankers and terminals are clearly much less at risk from fire, but there is an asphyxiation risk if collision should rupture a tank. This risk can be minimized by making certain that the high standards of construction and operation currently applied to LPG are also applied to carbon dioxide.

An accident to a liquid CO<sub>2</sub> tanker might release liquefied gas onto the surface of the sea. However, consideration of such an event is a knowledge gap that requires further study. CO<sub>2</sub> releases are anticipated not to have the long-term environmental impacts of crude oil spills. CO<sub>2</sub> would behave differently from LNG, because liquid CO<sub>2</sub> in a tanker is not as cold as LNG but much denser. Its interactions with the sea would be complex: hydrates and ice might form, and temperature differences would induce strong currents. Some of the gas would dissolve in the sea, but some would be released to the atmosphere. If there were little wind and a temperature inversion, clouds of CO<sub>2</sub> gas might lead to asphyxiation and might stop the ship’s engines.

The risk can be minimized by careful planning of routes, and by high standards of training and management.

## 4.5 Legal issues, codes and standards

Transportation of CO<sub>2</sub> by ships and sub-sea pipelines, and across national boundaries, is governed by various international legal conventions. Many jurisdictions/states have environmental impact assessment and strategic environmental assessment legislation that will come into consideration in pipeline building. If a pipeline is constructed across another country's territory (e.g. landlocked states), or if the pipeline is laid in certain zones of the sea, other countries may have the right to participate in the environmental assessment decision-making process or challenge another state's project.

### 4.5.1 *International conventions*

Various international conventions could have implications for storage of CO<sub>2</sub>, the most significant being the UN Law of the Sea Convention, the London Convention, the Convention on Environmental Impact Assessment in a Transboundary Context (Espoo Convention) and OSPAR (see Chapter 5). The Espoo convention covers environmental assessment, a procedure that seeks to ensure the acquisition of adequate and early information on likely environmental consequences of development projects or activities, and on measures to mitigate harm. Pipelines are subject to environmental assessment. The most significant aspect of the Convention is that it lays down the general obligation of states to notify and consult each other if a project under consideration is likely to have a significant environmental impact across boundaries. In some cases the acceptability of CO<sub>2</sub> storage under these conventions could depend on the method of transportation to the storage site. Conventions that are primarily concerned with discharge and placement rather than transport are discussed in detail in the chapters on ocean and geological storage.

The Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal came into force in 1992 (UNEP, 2000). The Basel Convention was conceived partly on the basis that enhanced control of transboundary movement of wastes will act as an incentive for their environmentally sound management and for the reduction of the volume of movement. However, there is no indication that CO<sub>2</sub> will be defined as a hazardous waste under the convention except in relation to the presence of impurities such as heavy metals and some organic compounds that may be entrained during the capture of CO<sub>2</sub>. Adoption of schemes where emissions of SO<sub>2</sub> and NO<sub>x</sub> would be included with the CO<sub>2</sub> may require such a review. Accordingly, the Basel Convention does not appear to directly impose any restriction on the transportation of CO<sub>2</sub> (IEA GHG, 2003a).

In addition to the provisions of the Basel Convention, any transport of CO<sub>2</sub> would have to comply with international transport regulations. There are numerous specific agreements, some of which are conventions and others protocols of other conventions that apply depending on the mode of transport. There are also a variety of regional agreements dealing with transport of goods. International transport codes and agreements adhere to the UN Recommendations on the Transport of Dangerous Goods: Model Regulations published by the United Nations. CO<sub>2</sub> in gaseous and refrigerated liquid forms is classified as a non-flammable, non-toxic gas; while solid CO<sub>2</sub> (dry ice) is classified under the heading of miscellaneous dangerous substances and articles. Any transportation of CO<sub>2</sub> adhering to the Recommendations on the Transport of Dangerous Goods: Model Regulations can be expected to meet all relevant agreements and conventions covering transportation by whatever means. Nothing in these recommendations would imply that transportation of CO<sub>2</sub> would be prevented by international transport agreements and conventions (IEA GHG, 2003a).

#### 4.5.2 *National codes and standards*

The transport of CO<sub>2</sub> by pipeline has been practiced for over 25 years. Internationally adopted standards such as ASME B31.4, Liquid transportation systems for hydrocarbons, liquid petroleum gas, anhydrous ammonia and alcohols' and the widely-applied Norwegian standard (DNV, 2000) specifically mention CO<sub>2</sub>. There is considerable experience in the application and use of these standards. Existing standards and codes vary between different countries but gradual unification of these documents is being advanced by such international bodies as ISO and CEN as part of their function. A full review of relevant standards categorized by issues is presented in IEA GHG, 2003b.

Public concern could highlight the issue of leakage of CO<sub>2</sub> from transportation systems, either by rupture or minor leaks, as discussed in Section 4.4. It is possible that standards may be changed in future to address specific public concerns. Odorants are often added to domestic low-pressure gas distribution systems, but not to gas in long-distance pipelines; they could, in principle, be added to CO<sub>2</sub> in pipelines. Mercaptans, naturally present in the Weyburn pipeline system, are the most effective odorants but are not generally suitable for this application because they are degraded by O<sub>2</sub>, even at very low concentrations (Katz, 1959). Disulphides, thioethers and ring compounds containing sulphur are alternatives. The value and impact of odorization could be established by a quantitative risk assessment.

### 4.6 **Costs**

#### 4.6.1 *Costs of pipeline transport*

The costs of pipelines can be categorized into three items

- Construction costs
  - Material/equipment costs (pipe, pipe coating, cathodic protection, telecommunication equipment; possible booster stations)
  - Installation costs (labour)
- Operation and maintenance costs
  - Monitoring costs
  - Maintenance costs
  - (Possible) energy costs
- Other costs (design, project management, regulatory filing fees, insurances costs, right-of-way costs, contingencies allowances)

The pipeline material costs depend on the length of the pipeline, the diameter, the amount of CO<sub>2</sub> to be transported and the quality of the carbon dioxide. Corrosion issues are examined in Section 4.2.2. For costs it is assumed that CO<sub>2</sub> is delivered from the capture system at 10 MPa.

Figure 4.3 shows capital investment costs for pipelines. Investments are higher when compressor station(s) are required to compensate for pressure loss along the pipeline, or for longer pipelines or for hilly terrain. Compressor stations may be avoided by increasing the pipeline diameter and reducing the flow velocity. Reported transport velocity varies from 1 to 5 m s<sup>-1</sup>. The actual design will be optimized with regard to pipeline diameter, pressure loss (required compressor stations and power) and pipeline wall thickness.

Costs depend on the terrain. Onshore pipeline costs may increase by 50 to 100% or more when the pipeline route is congested and heavily populated. Costs also increase in mountains, in nature reserve areas, in areas with obstacles such as rivers and freeways, and in heavily urbanized areas because of accessibility to construction and additional required safety measures. Offshore pipelines



generally operate at higher pressures and lower temperatures than onshore pipelines, and are often, but not always, 40 to 70% more expensive.

It is cheaper to collect CO<sub>2</sub> from several sources into a single pipeline than to transport smaller amounts separately. Early and smaller projects will face relatively high transport costs, and therefore be sensitive to transport distance, whereas an evolution towards higher capacities (large and wide-spread application) may result in a decrease in transport costs. Implementation of a 'backbone' transport structure may facilitate access to large remote storage reservoirs, but infrastructure of this kind will require large initial upfront investment decisions. Further study is required to determine the possible advantages of such pipeline system.

Figure 4.4 presents onshore and offshore transport costs versus pipeline diameter; where costs are based on investment cost information from various sources. Figure 4.5 gives a cost window for specific transport as function of the flow. Steel is a cost component for both pipelines and ships, and steel prices doubled in the two years up to 2005: this may be temporary.

**Figure 4.3.** Total investment costs for pipelines from various information sources for offshore and onshore pipelines. Costs exclude possible booster stations (IEA GHG, 2002; Hendriks et al., 2005; Bock, 2003; Sarv, 2000; 2001a; 2001b; Ormerod, 1994; Chandler, 2000; O&GJ, 2000).

**Figure 4.4.** Transport costs derived from various information sources for offshore and onshore pipelines. Costs exclude possible booster stations, applying a capital charge rate of 15% and a load factor of 100% (IEA GHG, 2002; Hendriks et al., 2005; Bock, 2003; Sarv, 2000; 2001a; 2001b; Ormerod, 1994; Chandler, 2000; O&GJ, 2000)

**Figure 4.5.** Transport costs for onshore and offshore pipelines per 250 km. High (broken lines) and low range (continuous lines) are indicated.

#### 4.6.2 *Costs of marine transportation systems*

Costs of a marine transport system comprise many cost elements. Besides investments for ships, investments are required for loading and unloading facilities, intermediate storage and liquefaction units. Further costs are for operation (e.g. labour, ship fuel costs, electricity costs, harbour fees), and maintenance. An optimal use of installations and ships in the transport cycle is crucial. Extra facilities (e.g. an expanded storage requirement) have to be created to be able to anticipate on possible disruptions in the transport system.

The cost of marine transport systems is not known in detail at present, since no system has been implemented on a scale required for CCS projects (i.e. in the range of several million tonnes of carbon dioxide handling per year). Designs have been submitted for tender, so a reasonable amount of knowledge is available. Nevertheless, cost estimates vary widely, because CO<sub>2</sub> shipping chains of this size have never been built and economies of scale may be anticipated to have a major impact on the costs.

A ship designed for carrying CO<sub>2</sub> from harbour to harbour may cost about 30-50% more than a similar size semi-refrigerated LPG ship (Statoil, 2004). However, since the density of liquid CO<sub>2</sub> is about 1100 kg m<sup>-3</sup>, CO<sub>2</sub> ships will carry more mass than an equivalent LNG or LPG ship, where the cargo density is about 500 kg m<sup>-3</sup>.

The estimated cost of ships of 20 to 30 kt capacity is between 50 and 70 M\$ (Statoil, 2004). Another source (IEA GHG, 2004) estimates ship construction costs at 34 M\$ for 10 kt-sized ship,

60 M\$ with a capacity of 30 kt, or 85 M\$ with a capacity of 50 kt. A time charter rate of about 25,000 US\$ day<sup>-1</sup> covering capital charges, manning and maintenance is not unreasonable for a ship in the 20 kt carrying capacity range.

The cost for a liquefaction facility is estimated by Statoil (2004) at 35 to 50 M\$ for a capacity of 1 Mt per year. The present largest liquefaction unit is 0.35 Mt yr<sup>-1</sup>. IEA GHG (2004) estimates a considerable lower investment for a liquefaction facility, namely 80 M\$ for 6.2 Mt yr<sup>-1</sup>. Investment costs are reduced to 30 M\$ when carbon dioxide at 100 bar is delivered to the plant. This pressure level is assumed to be delivered from the capture unit. Cost estimates are influenced by local conditions; for example, the absence of sufficient cooling water may call for a more expensive ammonia driven cooling cycle. The difference in numbers also reflects the uncertainty accompanied by scaling up of such facilities

A detailed study (Statoil, 2004) considered a marine transportation system for 5.5 Mt yr<sup>-1</sup>. The base case had 20 kt tankers with a speed of 35 km h<sup>-1</sup>, sailing 7600 km on each trip; 17 tankers were required. The annual cost was estimated at 188 M\$, excluding liquefaction and 300 M\$, including liquefaction, decreasing to 232 M\$ if compression is allowed (to avoid double counting). The corresponding specific transport costs are 34, 55, and 42 US\$ t<sup>-1</sup>. The study also considered sensitivity to distance: for the case excluding liquefaction, the specific costs were 20 US\$ t<sup>-1</sup> for 500 km, 22 US\$ t<sup>-1</sup> for 1500 km, and 28 US\$ t<sup>-1</sup> for 4500 km.

A study on a comparable ship transportation system carried out for the IEA shows lower costs. For a distance of 7600 km using 30 kt ships, the costs are estimated at 35 US\$ t<sup>-1</sup>. These costs are reduced to 30 US\$ tonne<sup>-1</sup> for 50 kt ships. The IEA study also showed a stronger cost dependency on distance than the Statoil (2004) study.

It should be noted that marine transport induces more associated CO<sub>2</sub> transport emissions than pipelines due to additional energy use for liquefaction and fuel use in ships. IEA GHG (2004) estimated 2.5% extra CO<sub>2</sub> emissions for a transport distance of 200 km and about 18% for 12,000 km. The extra CO<sub>2</sub> emissions for each 1000 km pipelines come to about 1 to 2%.

Ship transport becomes cost-competitive with pipeline transport over larger distances. Figure 4.6 shows an estimate of the costs for transporting 6 Mt yr<sup>-1</sup> by offshore pipeline and by ship. The break-even distance, i.e. the distance for which the costs per transport mode are the same, is about 1000 km for this example. Transport of larger quantities will shift the break-even distance towards larger distances. However, the cross-over point beyond which ship transportation becomes cheaper than pipeline transportation is not simply a matter of distance alone. It involves many other factors, including loading terminals, pipeline shore crossings, water depth, seabed stability, fuel cost, construction costs, different operating costs in different locations, security, and interaction between land and marine transportation routes.

**Figure 4.6.** Costs, plotted as transportation cost in US\$/t CO<sub>2</sub> against distance, for onshore and offshore pipelines, and ship transport. The costs include intermediate storage facilities, harbour fees, fuel costs and loading/unloading activities. Costs also include additional costs for liquefaction compared to compression. There is a capital charge factor of 11% for all transport options.

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## Tables

**Table 4.1.** Existing long -distance CO<sub>2</sub> pipelines (Gale and Davison, 2002) and CO<sub>2</sub> pipelines in North America. Reproduced by courtesy of Oil and Gas Journal.

Pipeline	Location	Operator	CO <sub>2</sub> Capacity (Mt yr <sup>-1</sup> )	Length (km)	Year Finished	Origin of CO <sub>2</sub>
Cortez	USA	Kinder Morgan	19.3	808	1984	McElmo Dome
Sheep Mountain	USA	BP Amoco	9.5	660	-	Sheep Mountain
Bravo	USA	BP Amoco	7.3	350	1984	Bravo Dome
Canyon Reef	USA	Kinder Morgan	5.2	225	1972	Gasification plants
Carriers						
Val Verde	USA	Petrosource	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	Turkish Petroleum	1.1	90	1983	Dodan Field
Weyburn	USA & Canada	North Dakota Gasification Co.	5	328	2000	Gasification Plant
Total			49.9	2591		

**Table 4.2.** Statistics on serious incidents, depending on the ship type

Ship Type	Number of Ships in 2000	Serious Incidents 1978-2000	Frequency (Incidents/ship year)
LPG tankers	982	20	0.00091
LNG tankers	121	1	0.00037
Oil tankers	9678	314	0.00144
Cargo/bulk carriers	21407	1203	0.00250

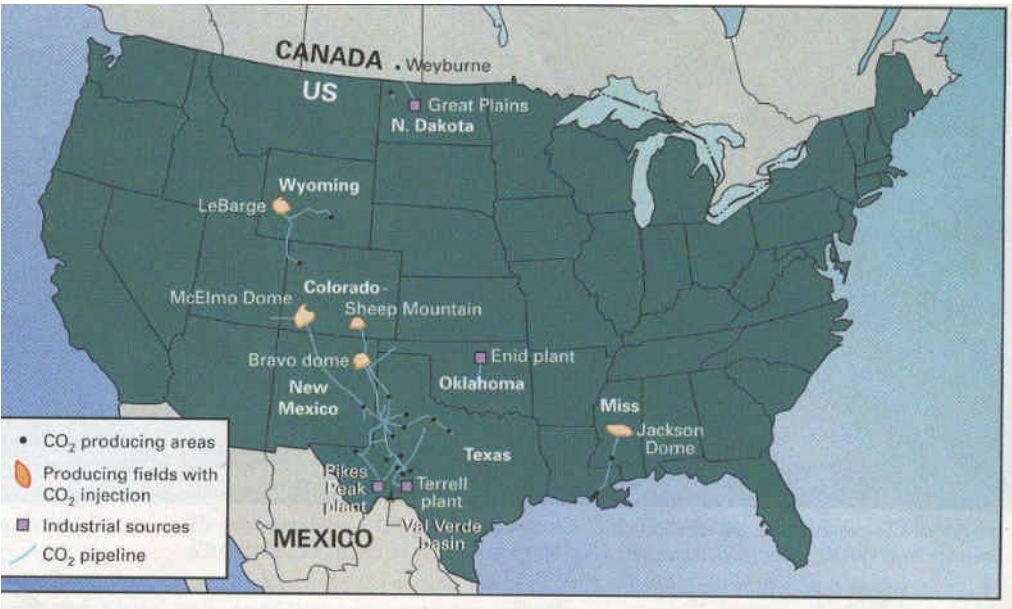


Figure 4.1. CO<sub>2</sub> pipelines in North America. Reproduced by courtesy of Oil and Gas Journal.

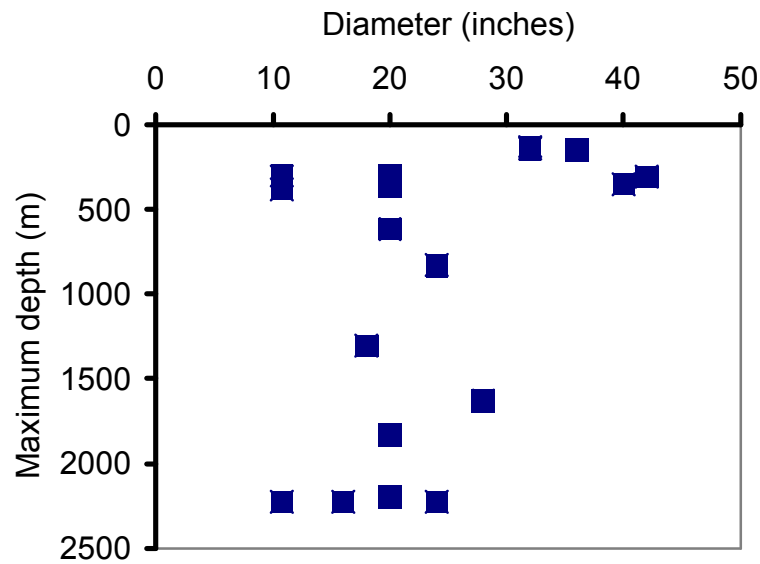
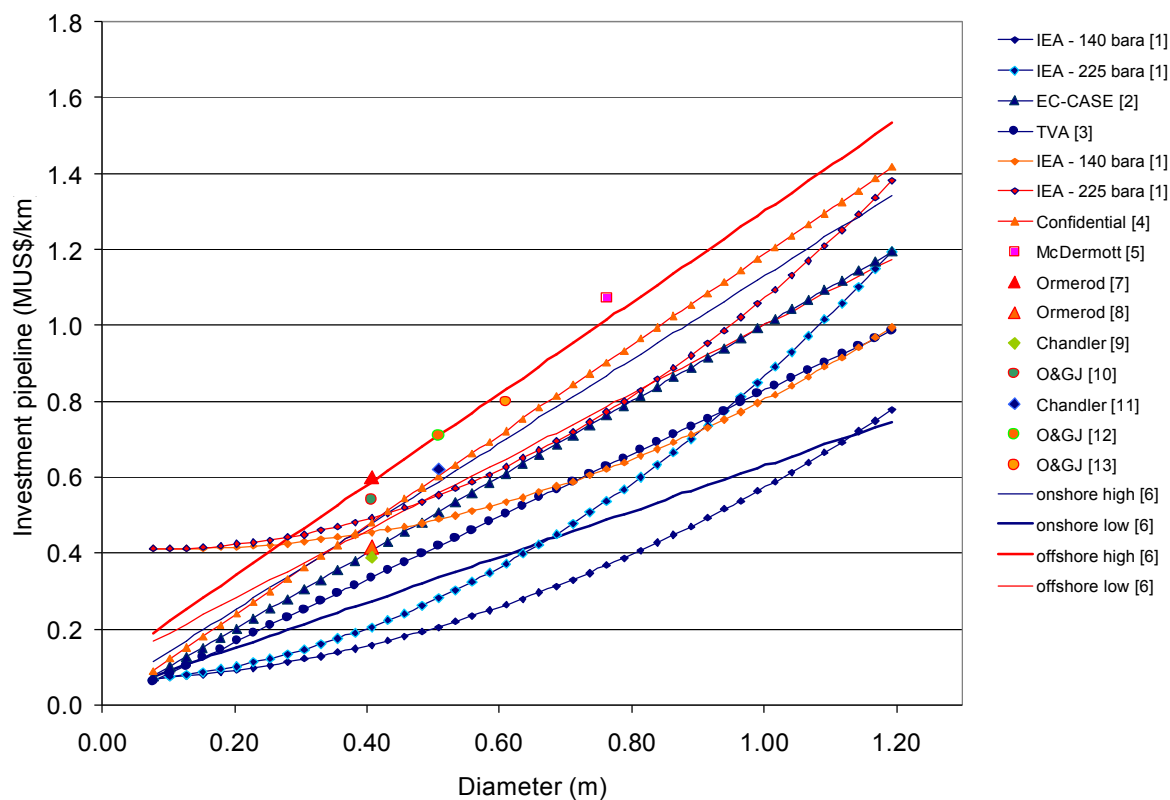
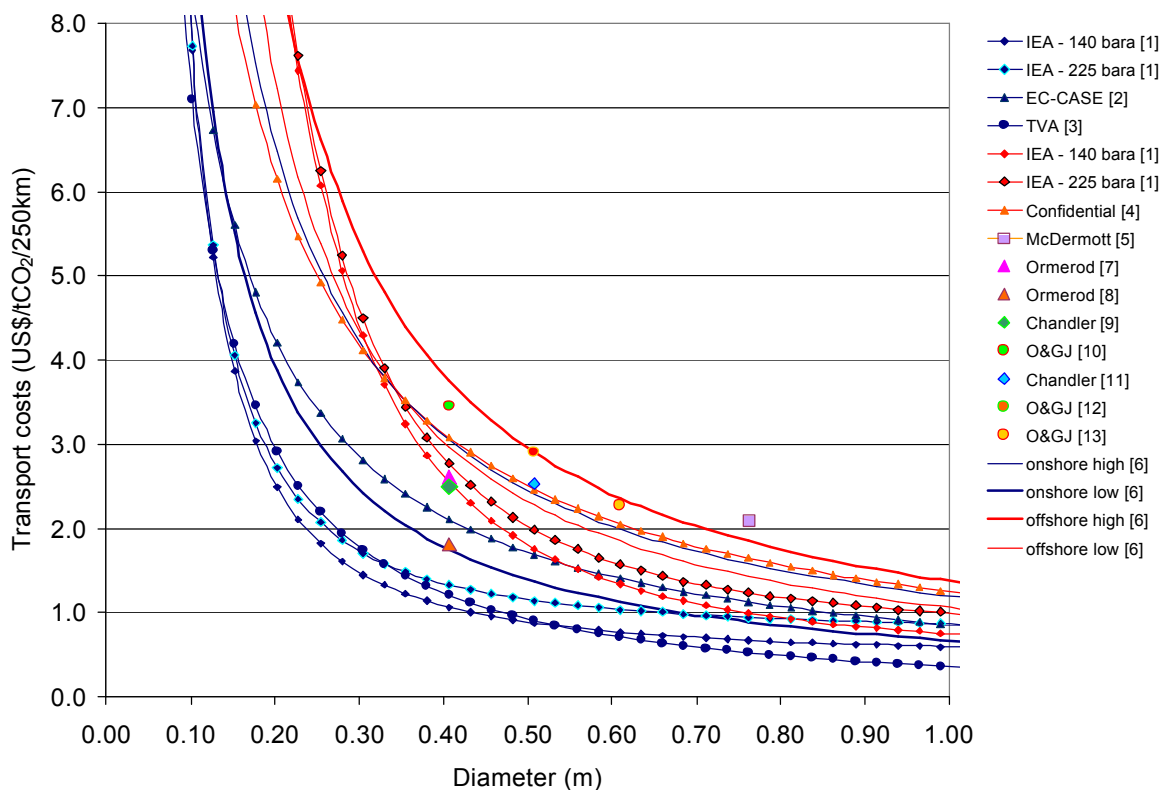


Figure 4.2. Pipelines in deep water.

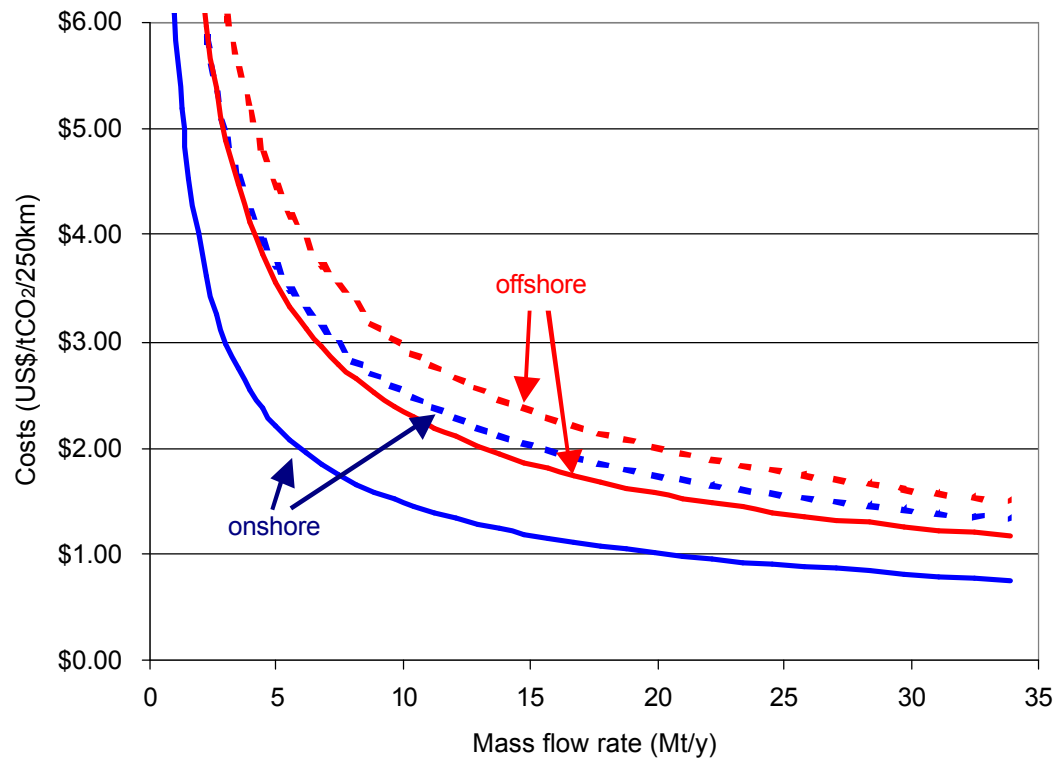


**Figure 4.3.** Total investment costs for pipelines from various information sources for offshore and onshore pipelines. Costs exclude possible booster stations (IEA GHG, 2002; Hendriks et al., 2005; Bock, 2003; Sarv, 2000; 2001a; 2001b; Ormerod, 1994; Chandler, 2000; O&GJ, 2000).



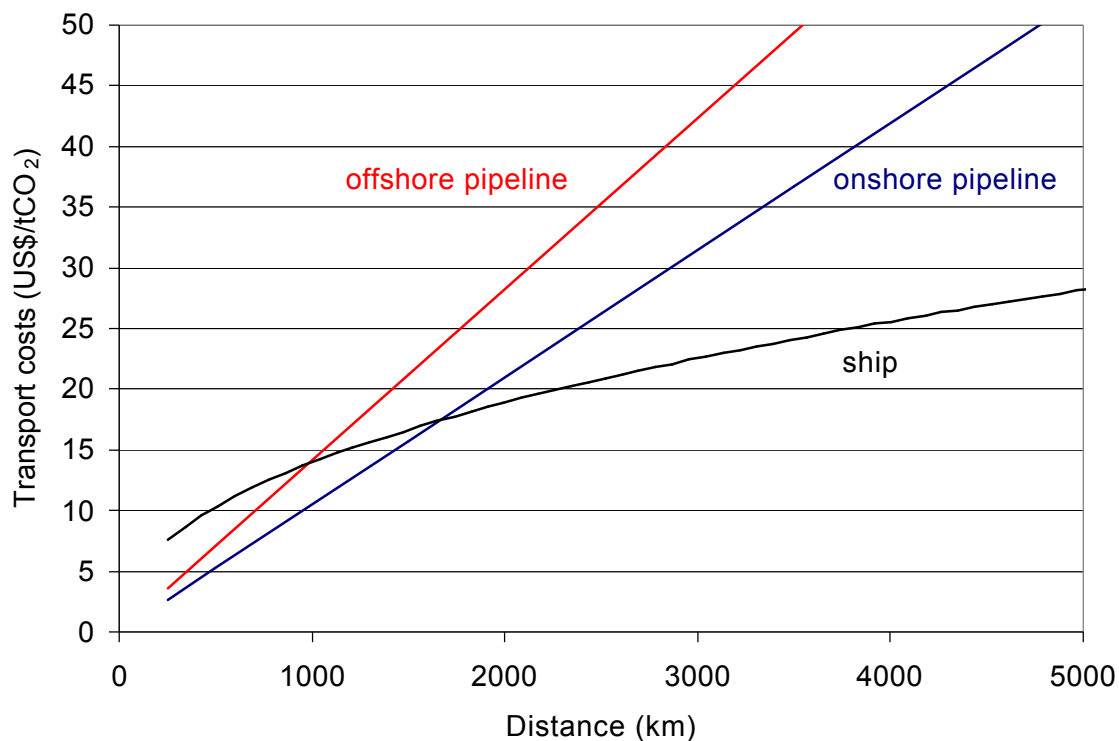
**Figure 4.4.** Transport costs derived from various information sources for offshore and onshore pipelines. Costs exclude possible booster stations, applying a capital charge rate of 15% and a load

factor of 100% (IEA GHG, 2002; Hendriks et al., 2005; Bock, 2003; Sarv, 2000; 2001a; 2001b; Ormerod, 1994; Chandler, 2000; O&GJ, 2000)



**Figure 4.5.** Transport costs for onshore and offshore pipelines per 250 km. High (broken lines) and low range (continuous lines) are indicated.





**Figure 4.6.** Costs, plotted as transportation cost in US\$/t CO<sub>2</sub> against distance, for onshore and offshore pipelines, and ship transport. The costs include intermediate storage facilities, harbour fees, fuel costs and loading/unloading activities. Costs also include additional costs for liquefaction compared to compression. There is a capital charge factor of 11% for all transport options.