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The Engineer's Guide to CO_2 Transportation Options

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Abstract

CO_2 transportation is the critical link between the CO_2 captured from an industrial facility and its storage in a geological facility. The transportation method and distance have a significant impact on the overall cost of CO_2 capture and storage. Several different transportation options are available for consideration when planning CO_2 capture, and storage (CCS) and CO_2 capture, utilization, and storage (CCUS) projects. In this paper, Trimeric will discuss onshore and offshore transportation options that project developers often consider when initially scoping the transportation component of a CCS or CCUS project. While pipelines are expected to be the dominant CO_2 transport method for large-scale projects, other options such as truck and rail for onshore transport and ship for offshore transport may facilitate point-to-point CO_2 transportation solutions where CO_2 pipelines are not available or are not technically or economically feasible. These alternative modes of transportation can also feed into larger CO_2 transportation hubs. Trimeric will discuss the CO_2 conditions (temperature, pressure, composition) required for pipeline and for liquid transport, how these can affect the capture process, the degree of processing required for the CO_2 product, and thus the overall economics of the project.

Liquid transport options have the potential to be deployed faster than a pipeline. A requirement for liquid CO_2 transport may favor a capture process that generates a liquid CO_2 product. For smaller-scale, onshore projects, several previous projects have used trucking and/or rail to transport liquid CO_2 from source to point of use. This is particularly true for shorter duration projects (≤ 1 year). Trimeric will discuss the limitations of these options with respect to daily CO_2 transportation rate and logistics and will provide relative costs for comparison with other transport methods. For offshore projects, shipping may be favored when transporting CO_2 over long distances, for example, where building a subsea pipeline would be cost prohibitive. This could be analogous to transcontinental LNG transportation by ship. The current transportation scale, a recent CO_2 transport ship order, and ideas for larger capacity ship CO_2 transport such as shipping liquid CO_2 in empty LPG or LNG transport vessels for the return trip from Europe to the U.S. are discussed. Liquid transportation methods may be less capital intensive than pipelines, but the opposite is true for operating costs. Trimeric will discuss the CO_2 conditions required for liquid transportation methods how these affect the processing and economics of CO_2 capture.

In most cases, large-scale CCUS projects will require pipelines for CO_2 transport. Trimeric will illustrate the process engineering decisions that are considered during the initial scoping phase of the pipeline design. Trimeric will discuss design basis parameters such as project CO_2 quantity (daily transportation rate), impurities, temperature, and pressure, pipeline routing, and the required delivery pressure at the surface of the storage site (injection well inlet). Trimeric will discuss pipeline design factors that project developers consider including preliminary route, topography (including elevation changes), geologic features, pre-existing right-of-way, surface and subsurface infrastructure, and population density.

As CO_2 flows through a pipeline, frictional losses result in decreasing pressure of the CO_2. Larger pipeline diameter (higher capacity) vs. smaller pipeline diameter with compressor / pump booster stations trade-offs will be discussed. CO_2 is commonly kept above its critical pressure throughout the pipeline to maintain desirable, stable, and predictable fluid properties including

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density, viscosity, and water carrying capacity (saturation limits). Pipeline operators also keep the fluid above the supercritical pressure to avoid issues with slugging or trapped liquid that could occur if a liquid CO_2 phase formed at pressure lower than the critical pressure. Trimeric will provide project examples to illustrate the technical and economic considerations that are relevant when evaluating the options for pipeline capacity (diameter) and booster stations. Trimeric will address the non-technical and non-economic factors to be considered for booster stations such as land disturbance, access to utilities, and mitigation of programmatic risks.

Examples of current transportation costs, capacity limits, and operating conditions are provided for each method of CO_2 transportation considered in this paper. Important safety considerations for each CO_2 transportation method are discussed.

Keywords: CO_2; CCS; CCUS; transportation; infrastructure; pipeline; ship; marine; rail; truck

1. Introduction

CO_2 transportation is a key component of carbon capture, transportation, storage, and monitoring. As shown in Fig. 1, the entire process from the CO_2 source to the storage facility must be considered to determine the most economic transportation method. Once the CO_2 has been captured, compression and other impurity removal steps (e.g., dehydration) are often required prior to CO_2 pipeline transport. Liquid transport of CO_2 requires different CO_2 processing including more extensive dehydration, refrigeration, liquefaction, distillation, temporary storage at the source and destination, and pumping. Key parameters for CO_2 transport include the project scale, duration, distance, and CO_2 capture and transport methods and conditions. There are many options for CO_2 transport with pipelines being the primary large-scale transport method. CO_2 is compressed and/or pumped above its critical pressure (73.8 bar for pure CO_2), typically to a minimum of 83 bar throughout the pipeline so that the CO_2 stays in a homogeneous phase with high density and low viscosity, which both make CO_2 more cost effective to transport by pipeline.

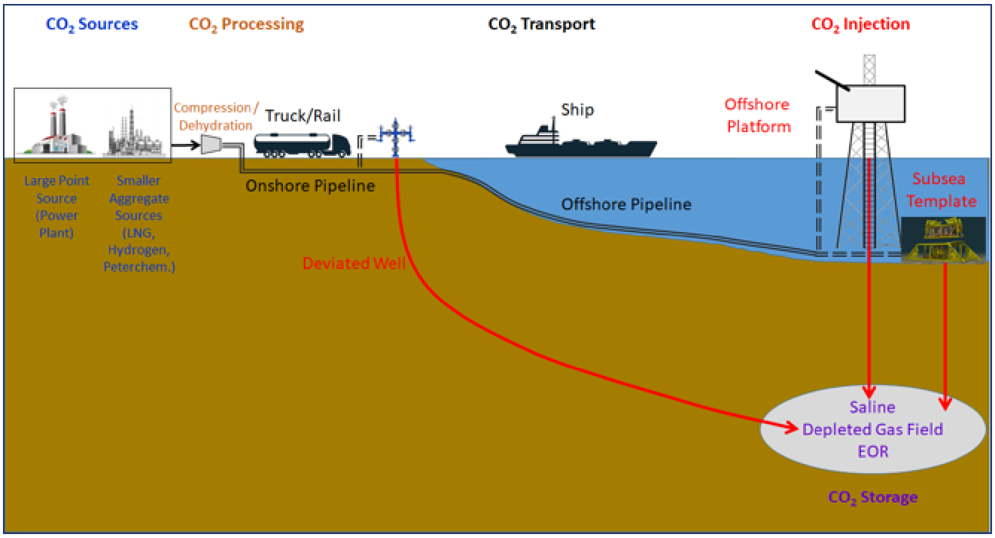

Fig. 1. Example CO_2 source and transportation options.

Pipeline transport is a mature process with over 40 years of operating experience and over 8,047 km of CO_2 pipelines in the United States [1]. This pipeline network could be expanded to facilitate additional carbon capture, utilization, and storage (CCUS) needs. CO_2 can also be transported as a liquid at low temperatures (< –18 °C) and relatively low pressures (< 20 bar) in trucks, railcars, and ships. These alternate methods are typically economic at smaller scales and shorter distances. Larger ship transport sizes and quantities in consideration for future projects may transport the liquid at lower temperatures and pressures approaching the CO_2 triple point (–56.6 °C, 5.2 bar) to increase liquid CO_2 density. Larger-scale ships in future projects may have advantages over pipelines depending on transport quantities, distances, and other project-specific factors. Alternate transport methods may also be useful to bridge the gap until necessary CO_2 pipeline networks are constructed.

This paper presents an overview of pipeline, ship, truck, and rail CO_2 transportation methods including process descriptions, applicability, typical operating conditions and impacts on processing, and costs. CO_2 transportation costs are project specific. Cost values presented in this paper were validated before publishing, but they are intended only to be used for relative comparisons of the different transport options.

2. CO_2 Transport Methods

Several CO_2 transport methods that could be used to deliver CO_2 from carbon capture facilities to storage are discussed in this section. These CO_2 transport methods include pipeline, ship, truck, and rail. Transport of solid CO_2 (dry ice) has been considered elsewhere, but it is not included here due to higher costs and lower transport quantity when compared to other CO_2 transport methods.

2.1. Pipeline

Large quantities of CO_2 have been routinely and economically transported by pipeline for over 40 years. The United States has significant experience with onshore CO_2 pipelines because of the approximately 8,074 km of pipeline used primarily for enhanced oil recovery (EOR). Most of these pipelines are buried at least 1 m underground. Fig. 2 shows a 400 mm commercial CO_2 pipeline at its above / below ground transition. Aboveground CO_2 transmission pipelines are used in some cases where existing infrastructure prevented installation underground. Fig. 3 shows the terminus of a 150 mm diameter pipeline at the injection well on the U.S. DOE Illinois Basin-Decatur Project 0.33 Mt/y (1 Mt total) CCUS demonstration project. As shown, insulation may be required on aboveground piping to maintain year-round stable injection temperature and pressure as the CO_2 density in the aboveground pipeline can be significantly influenced by hourly and seasonal variations in weather conditions.

Fig. 2. 400 mm diameter commercial CO_2 pipeline at above / below ground transition.

Fig. 3. Illinois Basin-Decatur Project Above-Ground, Insulated Injection Pipeline, 150 mm diameter, 2 km, Schedule 40 API 5L X52 Carbon Steel.

Pipeline transport is typically done at high enough pressures to keep the CO_2 above the critical pressure at all points in the pipeline system, even after accounting for any impurities in the CO_2 such as nitrogen or methane. Most CO_2 pipelines operate at pressures of 83 bar to 152 bar, and possibly up to 193 bar [1]. If the CO_2 is above its critical pressure (73.8 bar) and above its critical temperature (31.1°C), the CO_2 phase state is supercritical. If the CO_2 is above the critical pressure but below the critical temperature, the fluid state will be referred to as dense phase for the purposes of this paper. Fig. 4 shows the phases of CO_2 that are discussed in this paper as a function of pressure and temperature.

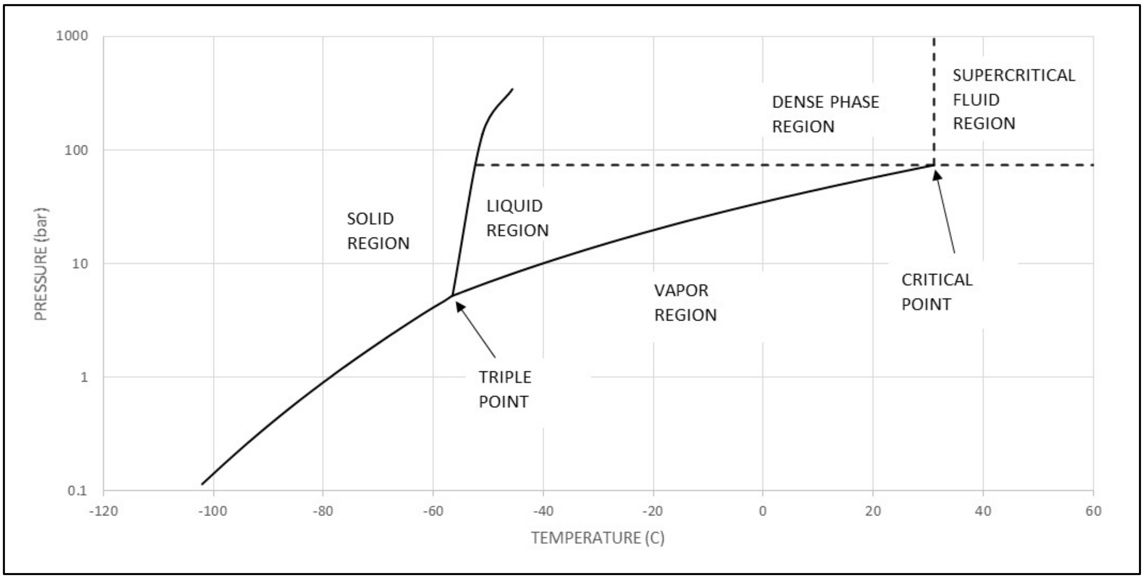

Fig. 4. CO_2 phase diagram.

A typical CO_2 pipeline maximum inlet temperature limit is 48.9 °C, but CO_2 pipeline inlet temperatures are often below that limit and with heat transfer that occurs as the CO_2 travels in the underground pipeline, the CO_2 will at times be below its critical temperature and thus - in the dense phase. At the pressure and temperature conditions in the pipeline, the CO_2 has a density similar to a liquid, but a viscosity similar to a gas. This allows for more efficient pipeline transfer (higher transport capacity and lower pressure drop) and helps attain the optimal conditions for injecting the CO_2 into EOR reservoirs (high density, low viscosity, and above the minimum miscibility pressure (MMP) for the CO_2 and hydrocarbons in the formation).

CO_2 onshore pipelines can be built in a similar manner as natural gas transmission pipelines. Some of the important parameters that need to be considered in the design include routing, topography, number of roads and river crossings, pipe hydraulics and material quality/thickness, internal and external corrosion protection, need for booster compression (or pumping), rights of way, and pigging [2].

In 2008, Norway developed the first offshore pipeline for transporting CO_2 that consists of 153 km of seabed pipeline [1]. If the CO_2 is non-corrosive (dehydrated to prevent any liquid water from forming in the CO_2), then constructing offshore CO_2 pipelines may be comparable to offshore hydrocarbon pipelines. Some of the important parameters for the design include pipeline route along the seabed, pipe hydraulics and material/quality thickness, stability of the pipeline on the seabed, external corrosion protection, impact from third parties, and installation method [2].

To meet future CCUS demand, the existing pipeline networks may be expanded through construction of new pipelines and in some instances, reuse of existing pipelines. Repurposing natural gas pipelines for CO_2 transportation will likely be limited to specific situations with more limited transport capacities and shorter distances. This is because CO_2 transport typically occurs at higher pressure than natural gas transmission and typically CO_2 requires a higher pressure-rated pipeline (ANSI 900 (153 bar) for CO_2 versus ANSI 600 (102 bar) for natural gas). Operating with CO_2 in a pipeline rated only for natural gas pressure would require many more booster stations, significantly increasing capital and operating costs for CO_2 transportation particularly as transport quantities and distances increase [1]. Operational maintenance for pipelines involves daily operations, maintenance / inspections, and safety / environmental activities. CO_2 transport losses in pipelines are negligible. Pipeline costs are discussed in detail in Section 3 in this paper.

2.2. Ship

Ship transportation may be an economic option for CO_2 delivery for some locations. Ships could be used to transport CO_2 in locations that have dispersed point sources and where waterways are prevalent. Shipping may also be more cost effective for transcontinental or intercontinental CO_2 transport rather than constructing new, lengthy pipelines.

To maintain high density CO_2 and minimize the size and pressure rating requirement of the ship, the CO_2 is transported as a liquid at low temperatures. The CO_2 is transported at a pressure around 18 bar and –23°C. This requires more extensive dehydration (compared to pipeline transport), refrigeration, condensation (liquefaction), compression / pumping processes, and often distillation to remove impurities such as oxygen, nitrogen, and methane. This approach also typically requires temporary liquid CO_2 storage (capacity for one to three days storage of the average daily transport rate) at both the source and sink since the CO_2 transport will be in intermittent, batch shipments.

Four small ships (~1,000 tonnes each) currently deliver liquefied food-grade CO_2 in northern Europe [1] [2]. A larger scale of ship transport of CO_2 is being considered in some cases such as the Northern Lights project. This Norwegian project recently placed an order for two CO_2 transport ships from Dalian Shipbuilding Industry Co. Each ship will be 130 m long and have a CO_2 transport capacity of 7,500 m^3 (~ 8,000 tonnes CO_2). The ships are expected to be ready for delivery in mid-2024 [3]. The price of the ships was not published. Ship CO_2 transport on an even larger scale could be similar to liquified petroleum gas (LPG) or liquified natural gas (LNG) tankers that could carry up to 45,000 tonnes of CO_2 and cost on the order of \$ 270 MM US per ship. When shipping larger volumes of CO_2, the operating conditions may be approximately 8 bar and –50°C near the triple point [1] to maximize the liquid CO_2 density at low pressure. Semi-refrigerated CO_2 ships may be used to help maintain the required temperature and reduce evaporative losses [4].

2.3. Truck

Trucks are a flexible and reliable method of small-scale CO_2 transportation. Transport of CO_2 by truck is common for food, beverage, and industrial uses. A typical truck can transport 18 tonnes of liquid CO_2, but truck sizes range from 2 to 30 tonnes [5]. Distance between the CO_2 capture facility (source) and the storage location (destination) is usually limited to about 320 km for economic reasons. The CO_2 liquid is typically transported at about 18 bar and –23°C. The trucks are insulated to help maintain temperature and reduce evaporative losses. Vapor balancing on the truck and the loading / receiving vessel limits CO_2 during loading and unloading of CO_2 from the truck to about 1% [1]. Fig. 5(a) shows a transport truck for refrigerated liquids such as CO_2 and Fig. 5(b) shows portable liquid CO_2 storage trailers used on the U.S. DOE Midwest Geological Sequestration Consortium Phase II injection tests. (Note – the portable storage trailers must be transported empty). Trucks can be used to assist with ship transport by delivering small volumes of CO_2 between ports and industrial sites. Trucks can also transport CO_2 in areas not yet accessible to pipelines or ship transport while the infrastructure for additional CCUS transportation is developed. The cost for a single CO_2 delivery truck is on the order of $290,000 US. Operating costs include items such as labor to drive the trucks and offload the CO_2 at the unloading site, fuel, maintenance, and repairs, and other (insurance, licenses, etc.).

Fig. 5. (a) transport truck for refrigerated liquid, figure courtesy of Airgas an Air Liquide Company; (b) portable liquid CO_2 storage containers.

2.4. Rail

In 2017, railroads in the US and Canada delivered approximately 10,000 shipments (713,000 tonnes) of refrigerated CO_2 [1]. U.S. Department of Transportation (DOT) specification 105 rail cars are used for transporting liquid CO_2 and they have a capacity of about 80 tonnes; however, evaporative and loading losses are higher in rail transport. An initial load of 80 tonnes in a rail car might result in a net delivery of as low as 63 tonnes, depending on rail transit time and loading / unloading operations. Transit times can be extended significantly if dedicated track is not available between source and destination. Rail cars containing CO_2 can wait idle for multiple days until the track is available again. Rail cars are equipped with three types of pressure relief devices, and regular venting of vapor is typical to reduce internal pressure. Typical transport losses of CO_2 range from 9% to 16% [1].

Empty rail cars are first transported by rail to the source facility. The cars are then loaded from CO_2 storage tanks at the source facility. Rail cars are loaded with liquid CO_2 at about 15 bar and –28°C. The rail cars have about 127 mm of urethane foam insulation to help maintain CO_2 temperatures for 8-10 days of transport [1]. The rail car is shipped from the loading facility to the off-loading facility by a rail freight company. The rail cars are offloaded and returned to the loading facility by the freight company. A considerable amount of time is required to load and unload rail cars because the rail cars need be connected / disconnected at the loading platform and moved (or switched) into place.

Rail cars are used for CO_2 transport over distances generally up to 1,610 km [1]. A rule of thumb from an industry expert is that truck transport is usually more economical than rail transport for distances between source and destination up to 640 km [6], so perhaps the optimal distance for rail transport is between 640 km and 1,610 km.

Higher transport quantity could also favor rail over trucking. Rail cars are used for point-to-point transfer and could be used as potential temporary transport solutions on CCUS projects until additional transport options such as pipelines or high-capacity shipping are developed. The cost for a single rail car is about $ 230,000 US. Other capital expenditures may include rail yard costs and a railcar moving device to relocate rail cars around the switching yard. Operating expenses are associated with shipping and labor for loading and unloading rail cars.

3. Comparison of Key Characteristics for CO_2 Transport Methods

Table 1 compares key characteristics for the CO_2 transport methods including CO_2 transport phase and operating conditions, approximate maximum capacity, and generalized cost comparisons. The cost information in the table is general in nature and provides a simple representation of the relative economics of the different transport options. CO_2 transport costs should be determined on a case-by-case basis for specific projects, applications, and operating conditions. Cost data from past years are scaled up to an April 2022 basis using the most recent Chemical Engineering Plant Cost Index (CEPCI) values [7].

Table 1. Key characteristics for CO_2 transport methods.

CO_2 Transport Method	Typical CO_2 Transport Phase and Representative Operating Conditions	Estimated Maximum Capacity (Note 1)	Generalized Cost of CO_2 Transport (Note 1, 2)
Pipeline (onshore)	Supercritical/dense phase (130 bar and 30°C)	52,600 t / day (19.3 Mt / y)	$ 7 US / t per 100 km (for >10 Mt / y) [5]
Pipeline (offshore)	Supercritical/dense phase (130 bar and 21°C)	52,600 t / day (19.3 Mt /y)	$ 14 US / t per 100 km (for > 10 Mt / y)
Ship (marine)	Saturated liquid (18 bar and -23°C) or at (8 bar and –50°C)	45,000 t / vessel	$ 62 US / t per 7,600 km each trip for 5 Mt / y [4]
Rail	Saturated liquid (15 bar and -28°C)	70 t / rail car	$ 110 / t [6]
Truck	Saturated liquid (15 bar and -28°C)	18 t / tanker	$ 110 / t [6]

Notes:

1) t = tonne, Mt = million tonne

2) Costs to compress and dehydrate, costs to liquefy and pump, and costs purchase CO_2 are not included.

Costs associated with compression to get the CO_2 into the supercritical phase and impurity removal (e.g., dehydration) for pipeline transfer are not included in Table 1 as they are typically considered as part of the carbon capture system. The additional costs to compress and dehydrate CO_2 from low pressure to 150 bar with 150 ppmv water in the CO_2 would be on the order of $ 15 US / tonne based on Trimeric in-house capital cost data for 1,000,000 tonne/yr plant capacity and $ 46 US / MW-hr cost of electricity. Costs for liquefaction for CO_2 transfer as a liquid by the alternate methods are not included in the estimates in Table 1 as they are typically considered as part of the carbon capture system. The additional costs to dehydrate, liquefy, and compress / pump CO_2 from low pressure to 150 bar with 10 ppmv water in the CO_2 would be on the order of $ 19 US / tonne based on Trimeric in-house capital cost data for 1,000,000 tonne/yr plant capacity and $ 46 US / MW-hr cost of electricity. Costs to purchase liquid CO_2 at ship, rail, or truck transport conditions are on the order of $ 66 US / tonne [6].

Published costs for onshore pipeline were given as a range of $ 1 -10 US / tonne (2012 basis) for 100 km of pipeline and a throughput > 10 MM tonnes/yr [5]. Adjusted to April 2022 costs, the $ 5 US midpoint of the 2012 range would now be $ 7 US / tonne. CO_2 pipeline costs can vary considerably depending on the location (onshore / offshore, populated area, rugged terrain, etc.), material costs, and operating conditions (capacity, distance, temperature, pressure). For example, a pipeline installed in a remote area cost approximately 3 times less ($1,679 US per km of pipeline per pipeline diameter in mm vs $4,873 US per diameter mm-km) than a pipeline constructed in a highly concentrated industrial and suburban area near a major US city. An average US onshore pipeline cost for six projects between 2009 and 2015 was $ 119,300 / inch-mile ($ 2,935 US / mm-km). Adjusted to April 2022 costs, this is $

171,300 / inch-mile ($ 4,215 US / mm-km) [1]. The maximum capacity listed in Table 1 for onshore CO_2 pipelines is based on the 30-inch (762 mm) Cortez pipeline in the US.

Offshore pipelines have many of the same cost factors and price differences as experienced with onshore pipelines. However, offshore pipeline costs are more expensive because of the equipment required to construct the pipeline underwater. Offshore pipelines may be on the order of 2 times more expensive than the onshore "equivalent". This factor is based on a limited set of offshore data for CO_2 pipelines and on comparison of onshore vs. offshore natural gas pipelines. There is a large range in costs (highly project and route specific). The maximum capacity listed in Table 1 for offshore CO_2 pipelines is based on the 30-inch (762 mm) Cortez onshore pipeline in the US.

Marine transport (transport by ship) may be less expensive than pipelines for distances greater than about 1,000 km and for CO_2 throughput less than a few million tonnes per year [4]. In some situations, transport by ship may offer some flexibility over pipeline transport. For example, transport by ship can accommodate CO_2 sources being added and removed over time without significant new pipeline capital investment. However, additional transport vessels (ships) and loading terminals and storage tanks could be required depending on the nature of the changes. The maximum capacity listed in Table 1 for a single vessel is based on similar LPG or LNG transport vessels. The ship transport cost value was based on a value published in literature for a 5.5 Mt / y marine transport system with 17 tankers with 20,000 tonne capacity each sailing 7,600 km on each trip at 35 km / h. The transport cost was $ 34 US / tonne (2004 basis) [4]. Adjusted to April 2022, this cost is $ 62 US / tonne.

Truck and rail costs for CO_2 transport are on the order of $110/tonne delivered. As stated previously, this does not include costs for the product CO_2 or for liquefaction of captured CO_2. Trucking is generally more economic than rail for one-way distances up to 640 km. Rail is typically more economic between 640 km and 1,610 km. See Sections 2.3 and 2.4 for more details on truck and rail costs, capacities, distance ranges, etc. [6].

The method(s) of CO_2 transport for a specific project must be selected after consideration of the upstream carbon capture process and system and the downstream injection and storage conditions to arrive at the optimal overall design for the CCS or CCUS project. The locations of the CO_2 sources and injection wells (inland, onshore near waterways, or offshore) will also impact CO_2 transport method selection. The transport conditions, capacity values, and cost values in this paper are current (April 2022) representative values and intended to be used for generalized comparisons. Every project will have a unique set of CO_2 transportation characteristics, capacities, costs, and other project-specific CO_2 transportation parameters. Economic conditions in general and for energy, oil, and gas industries more specifically at the time of the project can have a significant upward or downward impact on CO_2 transportation costs.

4. Hazards of Carbon Dioxide

Carbon dioxide presents several hazards during transportation and when processed in industrial settings:

- Toxicity and asphyxiation
- Low temperature exposure injuries (frostbite) and impacts on metallurgy; and
- Release of stored mechanical energy in pressurized systems.

Carbon dioxide is a slightly toxic gas that is dangerous at high concentrations. Carbon dioxide also acts as a simple asphyxiant by displacing oxygen, but the toxicity of carbon dioxide results in it being much more hazardous than nontoxic asphyxiants like nitrogen. For example, concentrations of 4 vol. % CO_2 or higher in air are considered to be immediately dangerous to life or health (IDLH). Concentrations of 10 vol. % and higher can produce unconsciousness and death [8].

Carbon dioxide is frequently stored, handled, and transported as a liquid in many industrial settings. The storage temperature for liquid carbon dioxide is typically below –12 °C, which is cold enough to quickly cause frostbite. And, when carbon dioxide is released from pressurized storage, it can cool further to temperatures as low as –78°C if dry ice is formed. Therefore, personnel need to be protected from low temperatures when working with or handling cold CO_2.

Carbon dioxide is also typically stored and handled under pressure, which creates the potential for injury caused by stored mechanical energy if the CO_2 is released from high pressure. High pressure jets of CO_2 are extremely dangerous and may cause severe injuries or death if a person is in the path of the jet. High velocity jets may also launch projectiles or cause the source (e.g., tubing, valve, vessel, pipe, etc.) to whip around violently or be launched at high velocity. In the case of vessel or pipeline rupture, the CO_2 may launch projectiles which may also cause injury or death.

There are many potential causes of mechanical failure of pressurized equipment, but two of the more common causes of equipment failure associated specifically with handling liquid CO_2 are 1) low temperature embrittlement of carbon steel, and 2) trapping of liquid CO_2 between valves. Most carbon steel piping systems and vessels are not designed to be operated at temperatures below –29 °C, and so under some conditions (typically during depressurization / repressurization operations) the carbon steel may reach temperatures that cause low temperature embrittlement. Embrittlement can lead to failure and loss of containment. Another hazard to be aware of occurs when low temperature liquid CO_2 becomes trapped between two block valves or is otherwise isolated in a section of pipe, vessel, etc. The CO_2 will warm up due to heat transfer from the surroundings. This can rapidly generate extremely high pressures, which can rupture the piping or vessel. The design of any system that contains liquid CO_2 should address both low-temperature embrittlement hazards and hazards associated with potential trapping of liquid CO_2 by including adequate pressure relief devices, administrative controls, operating procedures, and other approaches to prevent overpressure and low-temperature embrittlement failures.

5. Pipeline Design Considerations

This section presents an overview of a typical high-pressure, CO_2 supercritical / dense-phase pipeline design and the important factors that need to be considered in developing these systems.

5.1. CO_2 Process Design Considerations

There are many different variables that need to be considered in the pipeline design. The pipeline pressure is dictated by the hydraulics such as pressure drop and elevation changes, pressure requirement at the injection well, and sometimes by the density requirements at booster stations. Pipeline inlet temperature is typically dictated by the cooling medium available at the source (e.g., cooling water, air cooling). Heat transfer to / from the surroundings causes the CO_2 temperature to approach a steady state value in the underground pipeline. This temperature can vary based on location and other factors, but 30°C is a typical value in the Southern US based on Trimeric project experience. Impurities in the captured CO_2 also need to be considered.

Most CO_2 sources will be saturated with water vapor as is also the case with the CO_2 leaving many common CO_2 capture processes. Subsequent cooling can cause a free (liquid) water phase to form (water condensation). CO_2 is very corrosive to carbon steel in the presence of free water. During CO_2 compression and cooling, some water is condensed. However, this removal of water is usually not enough to transport CO_2 in carbon steel pipelines without the risk of water condensation or free water formation. The CO_2 is typically dehydrated further to prevent the possibility of liquid water forming in carbon steel CO_2 pipelines during operating as well as shut-in and extreme weather conditions. A trietheylene glycol (TEG) absorption unit is a common method used to remove water from CO_2 before it enters carbon steel pipelines, although others do exist. The dehydration unit is usually integrated at an intermediate pressure (typically around 45 bar) in the compression train where the water content of CO_2 is at a natural minimum due to previous compression and cooling steps. This reduces the capital and operating costs of the dehydration unit. Remaining water in CO_2 entering carbon steel pipelines in the US is on the order of 150 ppmv, with 633 ppmv (30 lb H_2O / MMscf CO_2) being a typical maximum limit. Lower limits have been proposed elsewhere.

Oxygen may need to be removed, particularly when CO_2 is transported in common carrier pipelines and / or used for EOR. Once CO_2 containing oxygen encounters a free liquid water phase (such as brine in a hydrocarbon reservoir), the mixture is much more corrosive than CO_2 without oxygen. H_2S is often removed due to toxicity and corrosion concerns as well as stress cracking concerns in certain grades of steel. In addition, non-condensable gases (at pipeline conditions) such as hydrogen (H_2), methane (CH_4), and nitrogen (N_2) in the CO_2 can diminish pipeline capacity, increase compressor / pump power requirements, and adversely affect the utility of the CO_2 mixture for use in EOR. The type and quantity of impurities in the CO_2 stream will vary depending on the emission source and the processes used to capture, compress/pump, and dehydrate the CO_2. Example specifications for some existing pipelines are shown in Table 2.

Table 2. Existing pipeline specifications [1].

Component	Units	Limit Ranges
CO_2 purity	% vol.	≥ 95
H_2O	lb/MMscf	< 12-45
	ppmv	< 250-950
H_2S	ppmw	< 10-45
N_2	% vol.	< 0.9 to 4
O_2	ppmv	< 10
Hydrocarbons	% vol.	< 4-5
Glycol	Gallons/MMscf	< 0.3
	ppbv	< 46
Temperature	C	< 32.2 to 48.9
Pressure	bar	≥ 83.7 and ≤ 152.7

5.2. Design Trade-offs – Example Case Study

In many cases, large-scale CCS and CCUS projects will require onshore pipelines for CO_2 transport. In this section, some of the process engineering decisions that are considered during the initial scoping phase of a pipeline will be illustrated using a recent project as an example. In the example project, CO_2 will be captured from one or more fossil fuel-fired power plants and delivered via pipeline to a common CO_2 storage facility. In the project's initial phases, the project team was concerned with defining the approximate routing and diameter of the CO_2 transportation pipelines and identifying the required support equipment (such as booster pump stations and storage site surface facilities) to identify potential ground disturbances for an environmental assessment.

The proposed project consists of up to three power plants each supplying CO_2 to a separate pipeline, which are then combined at a common storage facility. The design basis for the pipelines relied on information obtained from the utility company operating the power plants and the CO_2 capture technology providers. The design basis inputs included the maximum hourly CO_2 capture rates expected from the facility, the pressure at which CO_2 could be delivered from the CO_2 capture plants to the pipeline, the design maximum CO_2 temperature at the inlet to the pipeline, and other specifications for the captured CO_2 product. The maximum hourly CO_2 capture rate was based upon the maximum number of generating units operating at full load simultaneously for each of the power plants. The minimum and maximum CO_2 delivery pressures were constrained by project-specific design requirements for each CO_2 capture project. The pipeline inlet temperature was based on an estimated outlet temperature of 48.9˚C from the CO_2 capture facility. This is a typical maximum temperature limit on commercial CO_2 pipelines. The CO_2 purity specification will follow a typical commercial CO_2 pipeline purity for the United States (see Table 2).

The geological formation at the storage facility was modeled by an engineering firm with significant experience with underground utilization and storage of CO_2 to estimate the minimum CO_2 delivery pressure required at the wellhead. While the available data indicate that a wellhead pressure of 84 bar is sufficient, it is possible that further geological characterization may result in a revision to a higher required injection pressure. Higher delivery pressures could be accepted up to 111 bar, without risk of fracturing the storage formation. For the preliminary pipeline study, the delivery pressure from the CO_2 pipeline to the storage distribution piping was set at 91 bar, based on the minimum wellhead pressure of 84 bar plus an allowance for 7 bar of pressure drop between the end of the trunkline and the wellhead.

Project team members provided Trimeric with a rough approximation of a possible pipeline route from each of the power plant sources to the storage site. Trimeric used Google Earth images for initial approximations of pipeline distance and elevation changes to identify discrete waypoints along each pipeline route. CO_2 pipelines and pump stations were modeled in a process simulator using an equation of state that models CO_2 thermodynamic and physical properties across a wide range of pressures and temperatures with a satisfactory degree of accuracy.

For this preliminary study, Trimeric used a conservative approach of limiting maximum pipeline pressure to 139 bar to provide operating margin versus the ASME/ANSI pressure rating for a typical ANSI Class 900 CO_2 pipeline (152.7 bar for temperatures of –28.9 to 37.8°C). Trimeric is not aware of CO_2 pipelines with higher ANSI Class ratings; though technically feasible, higher operating pressures facilitated by a higher ANSI Class rating may pose first-time regulatory approval challenges and were not considered for this preliminary analysis.

The pipeline was modeled with a simplified starting approach setting heat transfer coefficients in the pipeline such that the CO_2 reached the ground temperature over a specified length of pipeline. This simplifying assumption is reasonable for a buried uninsulated pipe. The ground temperature was set as the maximum summer ground temperature for the area. Frictional losses associated with pipe roughness were included in the model. Smaller pressure drops associated with equipment upstream and downstream of the pump station were not included in the preliminary hydraulic model. Pipeline thicknesses were estimated by Trimeric using general guidance from ASME B31.8, with suitable material choices and corrosion allowances based on consultation with a CO_2 pipeline industry expert. As the project progresses to detailed design, these pipeline thicknesses will be revised by qualified mechanical engineers to reflect the final design conditions for the pipeline.

Using the hydraulic model, the smallest pipeline diameters were chosen for each pipeline with the following general constraints:

- Minimum delivery pressure of at least 91 bar at storage location to meet minimum wellhead pressure
- Minimum pressure upstream of the booster pump station of 84 bar to keep pressure well above the CO_2 critical pressure (73.8 bar)
- Maximum pipeline pressure of 139 bar to keep well below the pressure rating of the pipeline
- CO_2 density ≥ 640.7 kg/m^3, as lower densities can be challenging for multistage centrifugal CO_2 pump design
- CO_2 velocity below 4.6 m/s, which is a typical guideline for an economic CO_2 pipeline design.

The pipelines were first sized for operation with no booster pump station along the entire 289 km pipeline route; an example of pipeline sizing is shown in the first two results rows in Table 3. Pipeline diameters were rounded up to the nearest 101.6 mm (4-inch) increment for diameters greater than 304.8mm (12-inch), and up to the nearest 152.4 mm (6-inch) increment for diameters greater than 609.6 mm (24-inch). For the example pipeline in Table 3, which was sized for a maximum CO_2 capture rate of 394 tonne/hr (3.5 Mt/y), a 508 mm (20-inch) diameter pipeline would be sufficient to deliver CO_2 above the minimum required delivery pressure without need of a booster pump station along the pipeline route. Intermediate diameter pipelines (such as the 457.2 mm (18-inch) pipeline size shown in Table 3) could also deliver CO_2 at the required pressure without use of a booster pump station; however, this size is less commonly available, likely making the pipe and associated fittings more expensive. A more detailed analysis would be required to determine if these smaller but less-common pipe diameters could provide project cost savings.

A smaller diameter was then considered for each pipeline and a pump station was located at the point in the pipeline where the model indicated that the CO_2 pressure decreased to 84 bar. For the example with the 406.4 mm (16-inch) pipeline in Table 3, a booster pump station would be required 233 km from the CO_2 source. The actual location would be situated to account for land ownership along the pipeline route. For the example plant, adding a single pump station would decrease the pipeline diameter from 508 mm (20-inch) to 406.4 mm (16-inch). Further reductions in pipeline diameter by the addition of a second booster pump station would require pump station spacing of approximately 48 km to limit pressure drop and keep the CO_2 in the supercritical state. Trimeric considered this pump station distancing to be too short and too frequent (too many pump stations); thus, the results are not reported.

Table 3. Pipeline Diameter and Pump Station Options and Results for an Example Pipeline

Nominal Pipeline Size (mm / in)	Velocity in Pipeline (m/s)	Number of Booster Pump Stations	Distance from Source to Pump Station (km)	Pump Duty (kW)	Source Pressure (bar)	Booster Pump Outlet Pressure (bar)	Trunkline Delivery Pressure at Storage Site (bar)
508 / 20	0.61	0	--	--	15	--	110
457 / 18*	0.91	0	--	--	15	--	98
406 / 16	1.22	1	233	198	15	94	91

The decision to install booster pump stations requires a more detailed analysis of both economic and non-economic factors. Booster pump stations require additional land acquisition and land disturbance beyond the pipeline, and they also require electricity to be made available at the site. There are also programmatic risk differences (e.g., permitting and financing) between installing a larger pipeline vs. installing a smaller pipeline with a booster pump station. For some of Trimeric's clients, these financial, risk, land, and utility considerations dominate the decision; however, these types of considerations were beyond Trimeric's process engineering scope and the level of detail available at this stage of the project. A very simplified economic comparison showed that cost savings from using the 406 mm instead of the 508 mm diameter pipeline could be substantial even after including the capital and operating costs for single booster pump station with the cost of the smaller diameter pipeline. The work done up to this point lays the groundwork for future phases of engineering design. Then, costs for booster pump station land acquisition, getting power to the site, permitting, etc. and other programmatic considerations would also be included in further analysis to decide on the preferred approach.

6. Conclusions

CO_2 transportation is a key component of CCS and CCUS projects. CO_2 transportation costs can have a significant impact on overall project costs. Many large-scale projects will use onshore pipelines for CO_2 transportation. Other options that can be considered in some cases include offshore pipelines, marine (ship) transport, rail, and truck. The transport method dictates the pressure, temperature, and CO_2 phase such as saturated liquid at 15 bar and -28°C liquid in a truck and supercritical CO_2 at 130 bar and 30°C in a pipeline. Important safety considerations for each transport method considered were discussed earlier in the paper.

CO_2 transport quantity, rate, and distance will have a major impact on the transport methods considered, as will geographic considerations for the CO_2 source and destination. Pipelines are expected to be the dominant choice for large-scale projects. Offshore CO_2 pipelines can be on the order of twice as expensive as onshore CO_2 pipelines. Large distance over sea and /or long transcontinental or intercontinental routes may favor high-capacity marine transportation over pipelines, particularly for smaller to medium scale projects ($\leq$ 5 Mt/yr). Truck, rail, and small capacity ship (marine) transportation modes may have a role to play in the smallest scale, short duration projects. Here the upfront capital costs can be covered in shipping fees to third party transport companies and long-term logistics and sunk costs such as permitting and installation of a pipeline can be avoided.

Updated cost estimates (April 2022) basis were included earlier in this paper for each transport method considered. The reader should note that equipment, energy, and labor costs were very high at that time as compared to historical values even two years prior. Any CCS or CCUS project will have project-specific transportation costs driven by current general and energy sector economic conditions, transport quantities, rates, distance, project timelines and duration, geography of sources, destinations, and the routes in between, costs of capital, energy, and labor, regulatory and permitting considerations, and likely numerous others. The transport quantity ranges, distances, and costs presented in this paper can only be used for the reader to make generalized, relative comparisons.

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