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COMPRESSION TURBOMACHINERY FOR THE DECARBONIZING WORLD

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ABSTRACT

In the context of carbon reduction efforts, discussions evolve around hydrogen compression, as well as compression requirements related to CO₂ capture, transportation and sequestration. In this paper, compression requirements for various aspects of these applications are discussed, and the energy intensity of various energy transport configurations is compared.

Carbon sequestration by capturing, transporting and sequestering CO₂ from the exhaust of fossil fired power plants, from the generation of blue hydrogen, or the generation of Ammonia is discussed. Compression duties include the compression from capture pressure to pipeline pressure, the boost compression as part of the pipeline transport, and the compression required to sequester the CO₂. Issues addressed in this part include the relative effort required based on the CO₂ concentration in the exhaust, and methods to compress CO₂ and CO₂ mixtures from close to atmospheric pressure to pipeline pressure. In this discussion, the option of transporting hydrogen to a power plant versus transporting natural gas to said power plant, and transporting captured CO₂ back to a sequestration site, has to be evaluated.

The use and creation of hydrogen imposes specific questions on the use of turbocompressors. These questions involve the requirement to compress hydrogen for significant pressure ratios from production to a pipeline, the impact of transporting hydrogen in pipelines, and the compression from pipeline pressure to storage or vehicle fuel tank pressure. Part of the discussion is also the location of blue hydrogen production versus green hydrogen production, based on the fact that transport of CO₂ or natural gas requires less energy than the transport of hydrogen.

INTRODUCTION

Greenhouse gas reduction hinges on the use of hydrogen, as well as CO₂ avoidance, capture and sequestration [1,2,3,4,5,6]. In both cases, gas compression is necessary. The gas compression requirements associated have to address the fact that the challenges in compressing hydrogen are almost exactly opposite from the challenges of compressing CO₂. This includes the fact that most compression duties in this field will usually not be for pure gases, but gases with a certain amount of other gases mixed in. In the case of CO₂, many applications require operations in the supercritical region.

The gases involved, natural gas, CO₂ and hydrogen, show significant differences in their thermodynamic properties relevant to compression. With the simplified relationship between work and pressure ratio (Eq. 1) for ideal gases:

$$\frac{P_2}{P_1} = \left(1 + \frac{\eta}{c_p T_1} \cdot H \right)^{\frac{\gamma}{\gamma-1}} \quad (1)$$

and the relevant properties in Table 1, we can see that the pressure ratio achievable with the identical amount of work will be vastly different, under ideal gas conditions (for the purpose of this description, that means sufficiently distant from the critical point). Further, while the speed of sound for CO₂ is low, it is higher for natural gas and highest for hydrogen.

Table 1: Thermodynamic properties

| | Hydrogen | Natural gas | CO ₂ |
|--------------------------|----------|-------------|-----------------|
| Heat capacity (kJ/kgK) | 14.3 | 2.3 | 0.839 |
| Ratio of heat capacities | 1.4 | 1.3 | 1.3 |
| Speed of sound (m/s) | 1320 | 450 | 280 |

CARBON DIOXIDE

CO₂ is a relatively heavy gas with a low speed of sound, a low specific heat capacity, and a critical pressure and critical temperature in a range of typical compression applications. The combination of these features leads to the fact that turbo compressors achieve high pressure ratios and a high volume reduction per stage, but will often operate close to the speed of sound. For high overall pressure ratios, intercooling is essential to reduce power consumption, and to keep operating temperatures within customary limits. The high volume reduction per stage leads to challenges with matching impellers of subsequent stages, and makes it advantageous to use designs with gearboxes to increase the speed for higher pressure stages.

Lastly, operating conditions for pipelines and for sequestration tend to be in the range of supercritical or dense phase regions for CO₂ (Figure 1). These regions are characterized by high fluid density: while CO₂ still has the characteristics of a gas (for example, it is compressible, has a low viscosity, and fills available space) it has a density that resembles liquids. Supercritical fluids do not show any liquid-vapor phase change when the temperature is reduced. These regions are characterized by very strong sensitivity of the density to

temperature changes. This is a challenge for any compressor [7,8].

The thermodynamic concept of compressing or pumping CO₂ has to be considered for the different phases of CO₂ as a gas, CO₂ as a liquid, CO₂ in the two-phase region, supercritical CO₂ and dense phase CO₂ [2]. Because the critical pressure (73.9 bar) and temperature (31.1 °C) of CO₂ are in a range that is accessible for compression duties, and achievable for pipeline transport, the operation in supercritical and dense phases must be discussed. Furthermore, CO₂ in the supercritical or dense phase has a density similar to natural gas liquids (600 to 900 kg/m³), while still behaving like a gas, that is it is compressible and fills available space. It also has a low viscosity under these conditions, which makes the pipeline transport in the supercritical phase attractive.

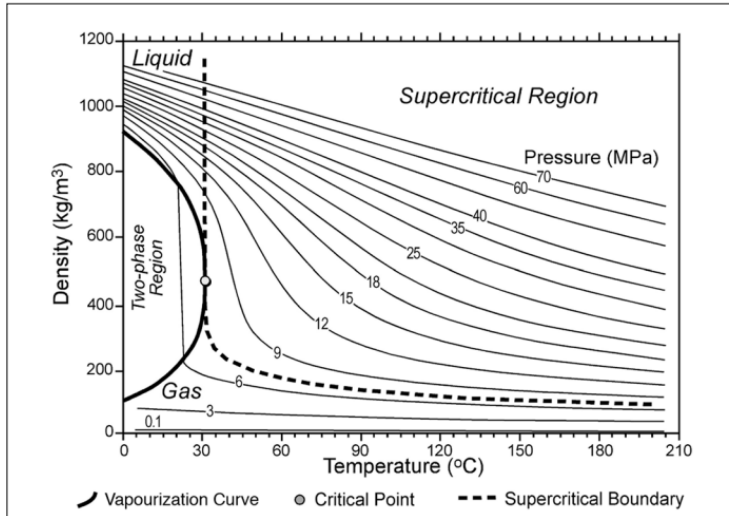


Figure 1: CO₂: density vs temperature and pressure [4]

In the context of carbon capture, transport and storage, there are several applications that require gas compression:

After capturing the CO₂ from the exhaust of a fossil fired plant, it has to be compressed either to a pressure that allows for the sequestration of the gas, or to a pressure that is required for efficient transport, for example in a pipeline. For most known capture methods, the CO₂ will be available at approximately atmospheric pressure, and it has to be compressed to either a reasonable pipeline pressure (typically 140 bar or above), or a sequestration pressure, which can vary between 100 bar and 500 bar depending on the sequestration site requirements. It should be noted that CO₂ from exhaust gas capture usually contains certain amounts of water, and other impurities. The water will have to be removed during the compression process, because liquid water with CO₂ forms carbonic acid, which corrodes materials. Like CO₂ from exhaust gas, the CO₂ from hydrogen generation is generally available at the same pressure range. CO₂ captured from Ammonia production, and cement production will likely also be available at relatively low pressures.

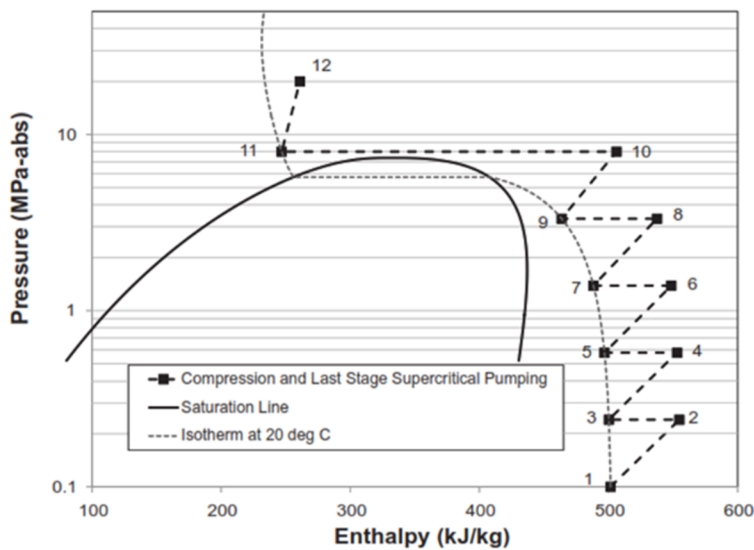


Figure 2: Compression of CO₂ (Mohitpour et al.,[2])

If the carbon dioxide is captured as part of processing natural gas (for example in a gas plant), it will typically be available at higher

pressures than in the aforementioned applications. However, the subsequent disposal follows the same rules. If the capture of the CO₂ is part of offshore, deep-water operations, and the CO₂ is used for enhanced oil recovery (EOR), high discharge pressure requirements (over 400 bar are known) are likely.

When CO₂ is captured from the exhaust of a fossil fired power plant, it may contain water, H₂S, CO, O₂, CH₄ (and higher alkanes), Nitrogen, Ammonia, Argon, Hydrogen, SO_x, and NO_x, dependent on the type of fuel used, the type of machinery and the methods for NO_x emissions reduction. Of these, Hydrogen has a major impact on the gas properties, while Nitrogen and Methane have a moderate impact, and the other contaminants have a smaller impact. The water content is important, because CO₂ in the presence of liquid water forms carbonic acid, which will cause corrosion issues. Free water can also lead to the formation of hydrates at typical pipeline pressures, and temperatures at 10 to 11 °C [2].

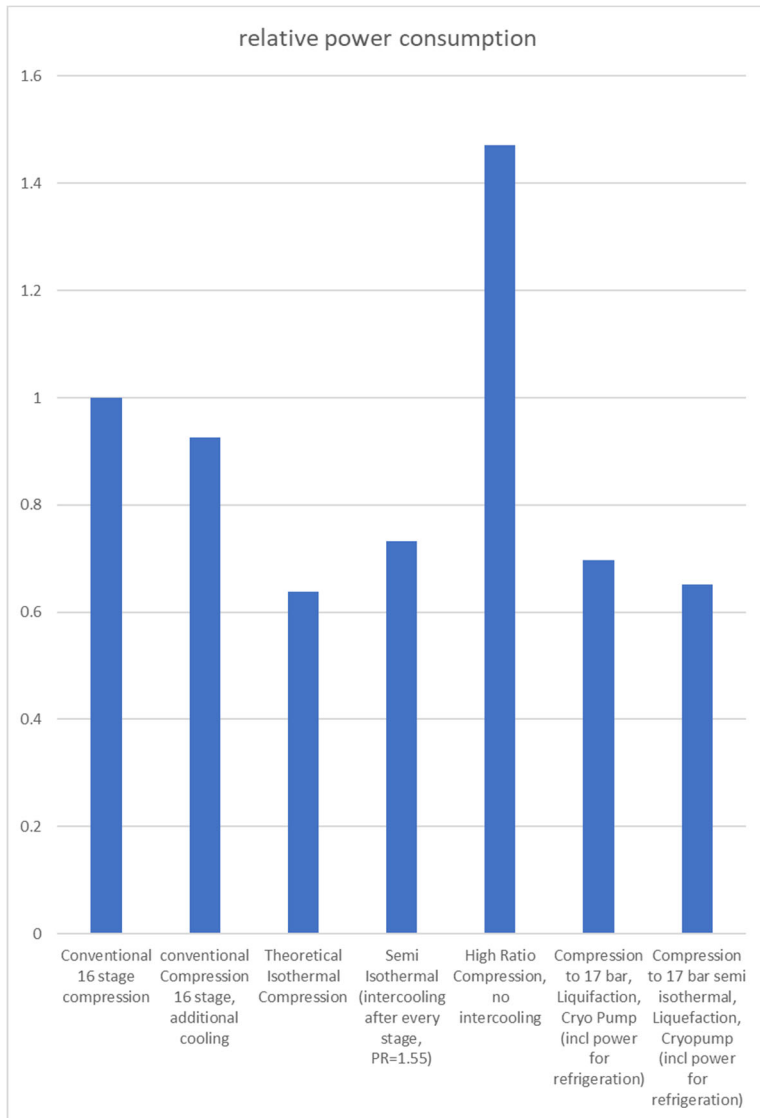


Figure 3: CO₂ capture compression (atmospheric to 153 bar), power consumption for a variety of compression options [9]

All capture technologies will likely leave small amounts of water in the gas (0.14% mole), which will have to be removed as part of the compression process to avoid corrosion issues. Pre-Combustion Technologies will leave small amounts of Hydrogen (1.7 mole%), Nitrogen (0.03 mole%) and Methane (0.035 mole%) in the CO₂ stream while post combustion methods avoid Hydrogen contamination. Oxyfuel combustion will yield significant levels of Argon (5.7mole %), Oxygen (1.6 mole %), NO (0.25%), and Nitrogen (0.06%) [2]. The captured gas from gas turbine exhaust and from the steam methane reforming (SMR) process will, besides the CO₂, contain some water (appr. 0.14% by mole [2]), while CO₂ from SMR will also contain CO (appr. 1.7%), Hydrogen (appr. 1.7%) and Methane (appr. 0.035%)[2]. This is particularly important in this discussion, because the behavior of CO₂ in the vicinity of the critical point is very sensitive to even small amounts of contaminants. Of interest for compression discussions are the equations of state (EOS) that allow the calculation of Enthalpy, entropy and density from pressures and temperatures. The Span and Wagner EOS is highly accurate for pure CO₂, and correlates well with experimental data [2]. GERG-2008 performs well, while the BWRS equation shows large deviations in the calculation of critical pressure and temperature.

Further, the captured CO₂ has to be brought to the sequestration site, which can be nearby, but which can also be at a significant distance, especially if the sequestration site is offshore. Pipelines from the capture site to the sequestration site may require intermediate compression or pumping stations. Impurities also affect the standard flow capacity of a pipeline. For a given pressure drop, and a given pipe diameter, and compared to the transport of pure CO₂, typical oxyfuel would reduce the pipeline capacity by 25%, while CO₂ with 5% Hydrogen content leads to a reduction of 11.5%, CO₂ with 5% Nitrogen or 5% CO leads to a 6% reduction. Other impurities show little impact on the flow capacity [2].

Once CO₂ is captured, and available with some impurities, it has to be sequestered, either by using it for enhanced oil recovery [8], or by storing in depleted oil and gas fields, or saline reservoirs (Mohitpour et al.[2]). Depending on reservoir depth and structure, the required CO₂ pressure at the wellhead may be anywhere from 100 bar to 500 bar. Other options, such as mineral carbonization, have been proposed, but will not be addressed in this paper.

CO₂ Compression

The question in this section is regarding the compression power that is needed to bring the carbon dioxide from supply pressure to a reasonable pipeline pressure (140 bara). This is expressed as work, with work defined as power consumption per unit of mass flow. The economical pressure increase from 1 bar to 140 bar requires multiple compression steps with intercooling in between (Figure 2). The enthalpy rise (or work) for each compression step is about 25 to 55 kJ/kg, which is achievable with a single centrifugal compressor stage, although it may require impellers to operate in the transonic range if the higher end of the head per stage is pursued, especially for the low pressure stages. For example, 10 stages of subsonic flow compression would require about 26 kJ/kg of head, while 6 stages at partially transonic compression would be at 50 kJ/kg of head. A comprehensive study of compression options [9] highlights the advantage of a semi-isothermal compression, that is compression with cooling after every stage (Figure 3).

El-Suleiman et al [10] have researched the impact of using different numbers of compressor stages. Their study shows the advantage of using multiple intercooled compression stages, but also shows that the pressure losses in the intercooler reduce the additional benefits of using 10 stages.

With some assumptions (8 stage intercooled compression plus an additional stage for the dense phase compression) we find (Figure 4) the amount of work required for the compression task to be for a discharge pressure of 140 bar. Two scenarios are evaluated, one with a suction pressure of 1 bar, another one with an elevated suction pressure of 2.8 bar. The second case uses 6 stage intercooled compression plus an additional stage for the dense phase compression. For all cases, a 3% pressure loss in the intercoolers is assumed. The significance of the dense phase compression (ref. step 11 in Figure 2) lies in the fact that the work for a given pressure ratio is significantly reduced, so a single stage can provide a significantly higher pressure ratio compared to the other stages. This stage will also experience gas at a very high density, in fact a density that is close to a density experienced by a liquid.

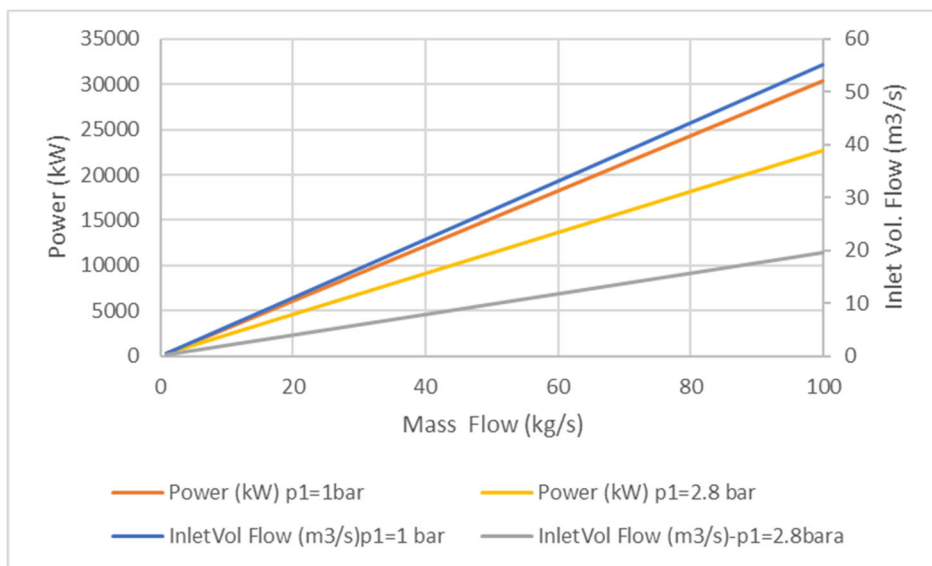


Figure 4: Compression of CO₂ (1 bar to 140 bar or 2.8 bar to 140 bar): Size of the compressor shown as inlet volumetric flow and power consumption for 83% stage efficiency, 3% pressure drop per cooler. Being able to provide CO₂ at higher pressures significantly reduces power consumption and compressor size. Compressor with 8+1 stages for p1=1 bar, 6+1 stages for p1=2.8 bar. The last stage is dense phase compression.

Figures 5 and 6 outline a few general challenges for the compression of captured CO₂: The inlet flow will generally require very large compressors. For example, even for 15 kg/s of inlet flow, the impeller diameter would be in the range of 850 to 900 mm. On the other

hand, due to the large pressure ratio achievable in a single compressor, the massive volume reduction would lead to very small impellers in the final stages of the same compressor.

The fact that the compression task will not be for pure CO₂ must be considered, as discussed earlier. The contaminants are small enough to avoid significant changes in the compression process, except for the dense phase compression, where the added contaminants as listed for the SMR process cause a sufficient change in the critical point to move out of the dense phase region. In either case, the water will have to be removed as part of the compression process, as water and CO₂ form acids that are corrosive, and require materials upgrades. The addition of a dehydration system will cause additional pressure losses in the compression system.

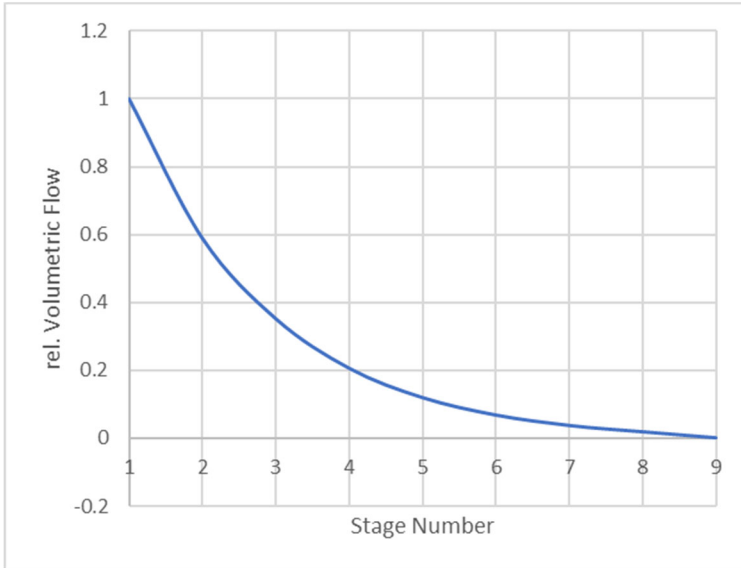


Figure 5: Flow reduction due to compression for 8+1 stages. Volumetric flow is reduced by a factor of over 300 from inlet to outlet of the compressor.

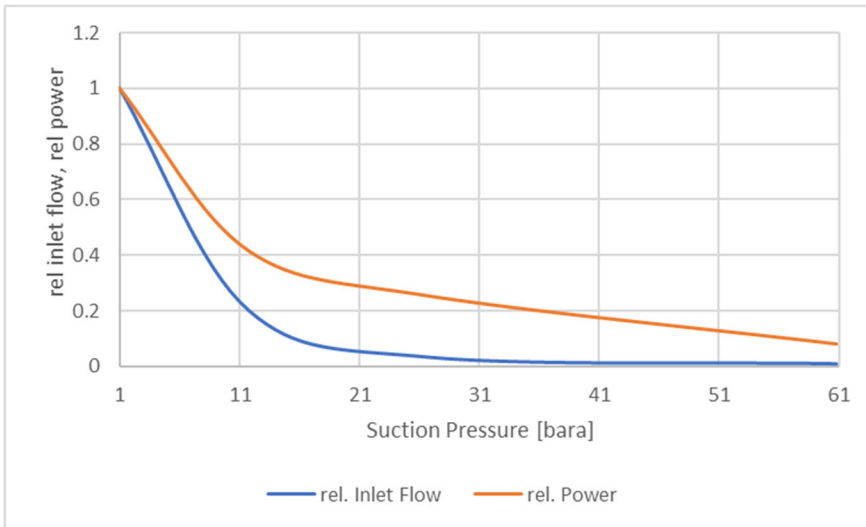


Figure 6: Impact of inlet pressure on power consumption and inlet flow. Discharge pressure 140 bar, intercooled solution.

Operation in the supercritical region

Depending on the application, some of the operating conditions may be in the supercritical region of CO₂. Due to fact that the critical pressure (73.9 bar) and temperature (31.1 °C) of CO₂ are in a range that is accessible for compression duties, and achievable for pipeline transport, the operation in the supercritical phase (thus just above the liquid-vapor dome) must be discussed.

In compressor or pump stages that operate near the dome, high flow velocities at the machinery inlet or in the inducer section of the impeller may be at risk to cause a phase change. Phase change will occur first at the compressor or pump inlet region due to local flow acceleration and the accompanying reduction in static pressure and temperature. This condensation or cavitation can potentially occur

in the inlet piping and transition geometry upstream of the inducer where total conditions approximately match cycle value and the fluid Mach number is relatively low. However, cavitation/condensation will likely be most severe at the inducer leading edge where total enthalpy is only slightly increased from cycle value based on inducer work but the fluid Mach number is significantly higher [11]. For evaluation purposes, the total enthalpy and Mach number used to evaluate the risk of phase change can be estimated based on cycle conditions at the compressor or pump inlet with Mach number calculated from inducer tip velocity. A higher accuracy evaluation can be performed by using total conditions and Mach number extracted from predicted flow field conditions (e.g., from computational fluid dynamic analysis results).

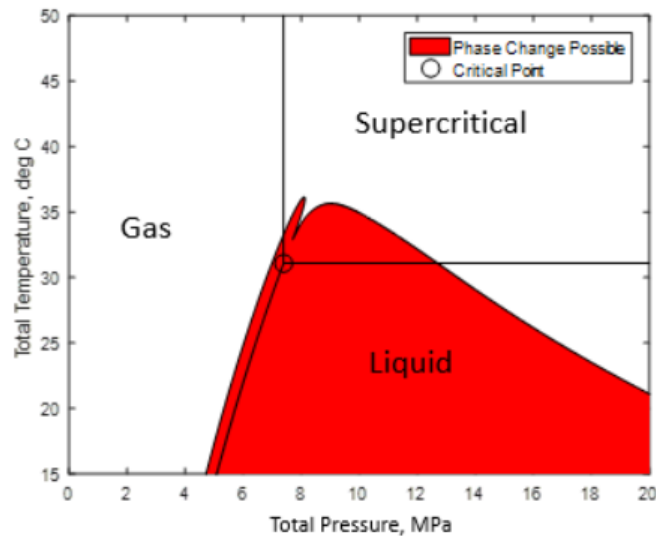


Figure 7: Example Set of Limiting Conditions [11]

Several publications have addressed the potential for and risks associated with operation in the two-phase region, including erosion, poor cycle stability/controllability, and compressor performance degradation. Allison and McClung [12] performed an analysis of compressor or pump inlet conditions that will result in static conditions on the saturation line for all vapor-liquid saturation conditions around the entire two-phase region (liquid and gas sides of the dome). To aid interpretation of results, an example results plot for $M = 0.4$ is shown in Figure 7 with different fluid states and limiting conditions near the critical point.

The border of the red-shaded curve represents a set of conditions that will result in a saturated equilibrium static condition for a particular Mach number. Total conditions that fall in the area inside/below each curve may result a two-phase mixture at static conditions, and total conditions above/outside the curve will avoid two-phase conditions at the specified Mach number. The left side and lower-right corners of the plot correspond to gas-phase and liquid-phase conditions, respectively, and the upper-right corner corresponds to the supercritical region.

Limiting conditions are calculated for Mach numbers varying from 0.0 to 1.0, which is considered a sufficient range of likely Mach numbers for different compressor designs. The resulting set of limiting total conditions is shown in Figure 8 and spans a wide range of temperature-pressure conditions that will result in phase change, i.e. from the triple point (-56.4 °C, 0.52 MPa) to temperatures and pressures up to 66.95 °C and 630.9 MPa, respectively. As expected, the results show that the range of conditions that may cause two-phase behavior increases significantly with Mach number. At a Mach number equal to zero, the range collapses onto a saturation temperature-pressure line ending at the critical point. The limiting curves exhibit peak temperatures and non-monotonic behavior near the critical point, but it is difficult to see at this scale.

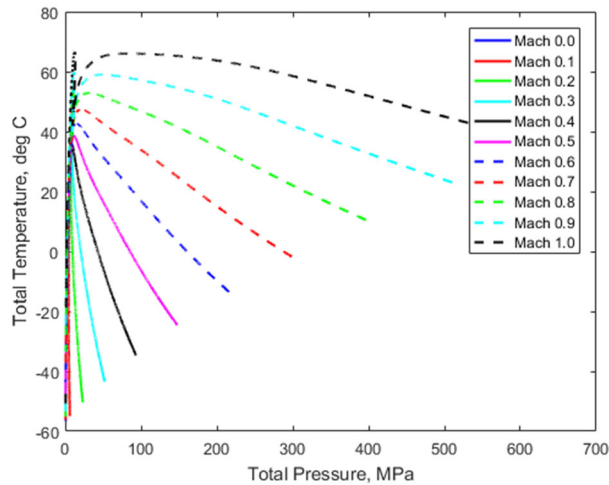


Figure 8: Full Range of Limiting Total Conditions for Phase Change in sCO₂ at Mach Numbers up to 1.0 [12]

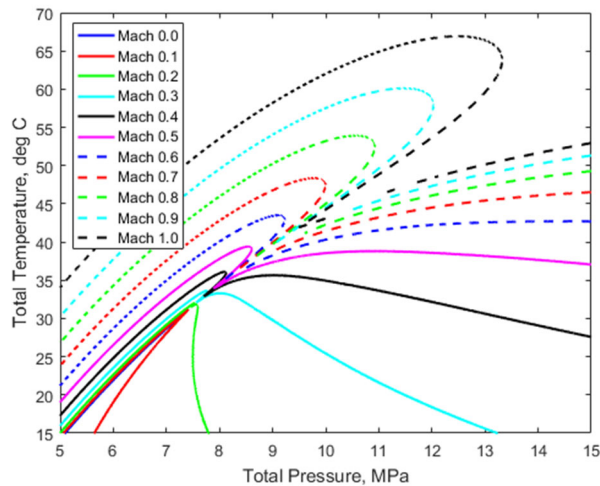


Figure 9: Limiting Total Conditions for Phase Change in sCO₂ Near Critical Point at Mach Numbers up to 1.0 [12]

sCO₂ compressor and pump designers will be most interested in limiting total conditions near ambient temperature due to economic heat rejection capabilities for the cycle application. Limiting conditions for temperatures between 15 and 70 °C and pressures between 5 and 14 MPa are shown in Figure 9. Limiting conditions in this region continue to show a strong dependence on Mach number, with a rapid expansion in the range of “high-risk” total pressures that may result in two-phase behavior. Interestingly, the results also show a sharp change in limiting conditions near the critical point that indicates a narrow range of “safe” pressures and temperatures that will avoid phase change, even at high Mach numbers. At Mach 0, this range resolves to a single point (the critical point) as can be seen in Figure 9 [12]. This sharp variation is due to the strong sensitivity of temperature to enthalpy near the critical point.

Lettieri *et al.* [13] and others analyzed the nucleation time required for condensate to form in a sCO₂ fluid and show that for inlet conditions away from the critical point, nucleation time is typically larger than the residence time of the fluid in the compressor inlet. In this case, the fluid in the compressor inlet exists in a non-equilibrium or metastable state. In the cited work, an alternate condensation limit was defined as the ratio of the residence time of the fluid in the condensing region to the nucleation time. As long as this ratio is significantly less than unity, the residence time is less than the nucleation time and condensation would not be expected. Their analysis results show that two-phase effects are still expected to be prominent near the critical point, and test results showed increasing uncertainty in nucleation time as the temperature approaches the critical temperature, so caution is still recommended for operation near the critical point.

In [13], experimental investigations of non-equilibrium condensation were completed using laser interferometry with a blowdown testing of a de Laval nozzle. These experiments characterized the conditions for non-equilibrium condensation (i.e. the Wilson line, see Figure 10) for five test cases starting in the gas and supercritical phase (5.8-8.4 MPa, 36.85 – 38.85 °C). The authors also performed simulations of a particular centrifugal compressor design showing that consideration of nonequilibrium condensation enables 16% power savings

by operating at reduced inlet temperatures. While valuable, these results are focused on a particular nozzle geometry and narrow range of conditions above the critical temperature, so cannot be applied generally for a broad range of inlet conditions.

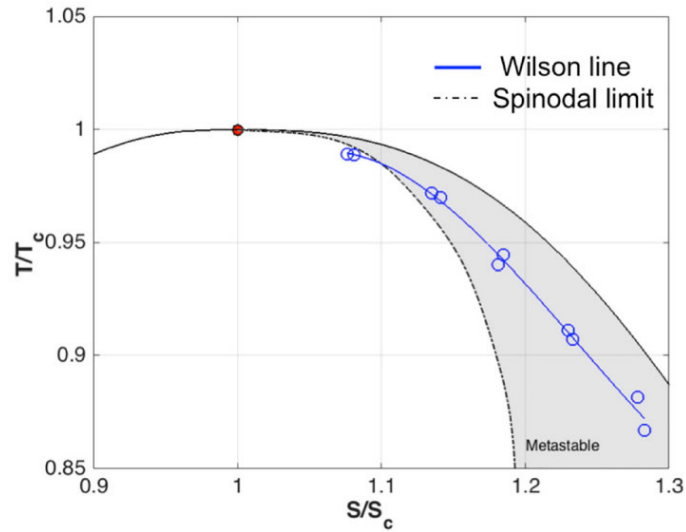


Figure 10: Nonequilibrium $s\text{CO}_2$ Condensation Behavior from de Laval Nozzle Experiments [13], Temperature T and Entropy S , normalized with their respective critical values.

Pipeline transport

IPCC [14] indicates that prospective areas for CO_2 sequestration do not line up with large sources of CO_2 production. Further, in many areas, the sequestration sites may be offshore. This indicates the need for CO_2 transportation solutions. While CO_2 can be transported in pipelines over a wide range of pressures, transport in the dense phase region has a number of advantages: While CO_2 is still compressible and behaves like a gas in terms of viscosity, its density is close to that of a liquid. Thus, transport in dense phase is very energy efficient, and certainly the preferred mode for longer distances. A few things need to be considered:

While in natural gas pipelines, elevation changes are only responsible for secondary effects, in dense phase CO_2 , elevation changes lead to significant changes in gas pressure. The pipeline has therefore to be sized such that under all operating conditions and operating temperatures, the CO_2 stays about the critical pressure, and does not cross into the two-phase region. Also, rapid density changes as a result of temperature changes have to be considered when sizing equipment. The properties of CO_2 in dense phase raise the question whether pumps or compressors can be used in this application (Figure 11). CO_2 in dense phase is compressible, and there are no phase changes. The duty can thus be handled efficiently both by compressors and pumps.

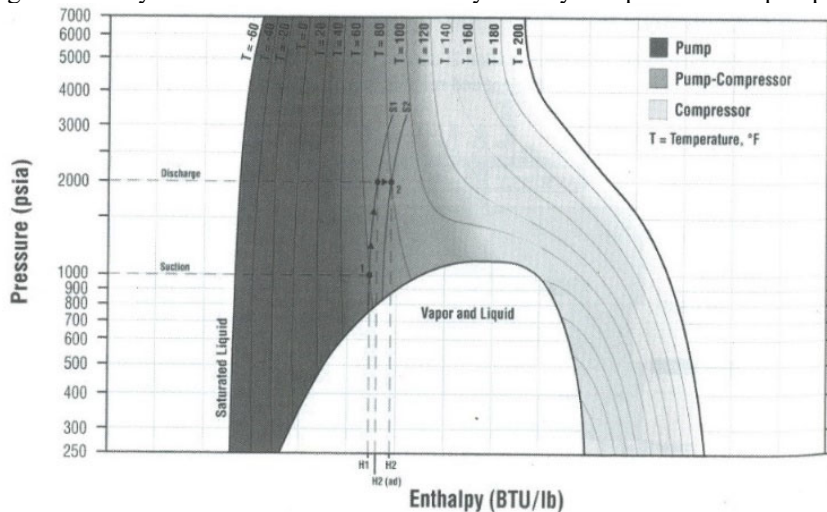


Figure 11: Pipeline transport of CO_2 in dense phase [2].

Calculations, using commercially available pipeline simulation software show that for a 30 in (760 mm) diameter pipeline, flowing 1300 MMSCFD of CO_2 modelled after an existing CO_2 pipeline in [15] show a pressure drop from 152 bar to 90 bar, after a distance between stations of 210 km (130 miles). No elevation changes were simulated. The power consumed for recompression from 90 bar to 152 bar is 8550 kW (11500 hp) with a single stage centrifugal compressor, running at low tip speed (machine Mach number 0.52) at an assumed,

but realistic polytropic efficiency of 86%. The pressure ratio is higher than what would be used in an optimized natural gas pipeline.

Transporting CO₂ in dense phase conditions (Figure 11) has a number of advantages, since it combines a high density with a viscosity that is in the same range as a gas, rather than that of a liquid. Supercritical CO₂ is compressible, so increased pressure leads to increased density, and like a gas, it fills any available volume. Unlike gas in the subcritical range, there is no phase change when it is cooled. Existing pipelines operate at pressures between the critical point and up to 200 bar, typically between 85 and 150 bar to maintain single phase operations in the dense phase region. The upper pressure limit is based on the mean allowable operating pressure and maximum allowable pressure as determined by the physical pipeline design. Pressure will vary along the length of the pipeline due to viscous, or pipe friction losses, change in elevation, and thermodynamic effects associated with changes in temperature. Pressure changes due to environmental thermal input and elevation profile can be significant for CO₂ pipelines. In addition to thermal flux from the environment, isenthalpic effects associated with a sudden pressure drop, such as across a throttling valve, can cause localized temperature changes. Care must be taken to open valves slowly in order to minimize local thermal gradients which can result in phase changes and transients within the piping system. If a phase change were to occur at a valve, significant damage could result from the high gas flow velocities associated with the liquid to gas phase transition [16]. Due to these features, both pumps and compressors can be used as boosters for pipelines. Compressors would run relatively slow, but significantly faster than a pump. The pressure ratios are low, booster stations will be placed about 150 to 250 km apart, thus requiring a pressure ratio of about 1.5 to 1.7.

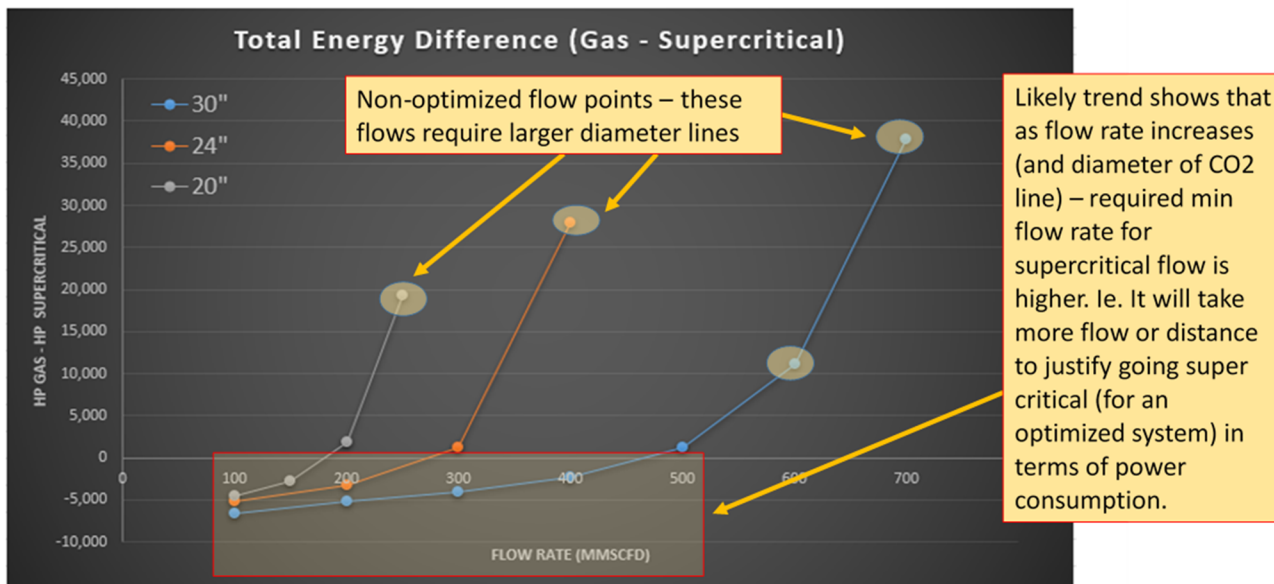


Figure 12 : CO₂ Transport in gas or supercritical state.

At elevated pressures above the critical pressure, CO₂ can be transported in a dense phase state (Figures 1 and 11) using electric driven pumps that maintain pressure and temperature above its critical point. This strategy of pumping the CO₂ versus compressing CO₂ in gas phase compressors is often dictated by the volume flow rate of the pipeline. For smaller volumes, compression in the gaseous phase is preferable because the overall power consumption will be less since pressurization above 2200 psi is not required. Thus, the gas phase compressors operate around typical natural gas pipeline pressures. However, for greater volumes of CO₂, as shown in Figure 12, it is worth the cost of initially compressing the CO₂ to the dense phase / supercritical state since it can then be pumped at overall lower power costs than compression. Figure 12 illustrates this breakover point, where the overall power consumption between supercritical state and gas phase (y-axis) will be less for the supercritical pumps, at three diameters of 20", 24" and 30" lines and for flow rates between 100-700 mmscfd (x-axis). For example, for a 24" CO₂ pipeline (middle orange line), the power spent in compressing up to the supercritical state and then pumping CO₂ is less than the gaseous compression power for flow rates of 300 mmscfd or more.

It should also be noted that the pipeline flows should be optimized to diameter such that a larger diameter choice will incur less pressure drop and keep the power consumption lower. Once the power consumption difference starts to increase exponentially (Figure 12), a pipeline designer would choose to increase the pipeline diameter to incur a lower power demand, in either the gas phase or supercritical state. Finally, temperature effects should also be taken into account since the dense phase CO₂ transport will be more sensitive to temperature changes, especially for the pipeline route ground temperatures. A CO₂ pipeline optimization study should consider these temperature effects to assure that the pumps can maintain pipeline pressures, given the expected fluid temperatures and mixture composition.

Another consideration is that transporting CO₂ in dense phase will not allow the re-use of existing natural gas pipelines, which are typically rated for approximately 1500psi (105 bar) MAOP. While 1500psi (105 bar) is still above the critical pressure, operability

concerns (for example the large change in volume for relatively small changes in temperature (Figure 1) may prevent operation in that range. The option then becomes to reduce the operating pressure even further, ie to 400 to 600 psi (28 to 41 bar) MAOP, because at higher pressures, changes in ambient temperature may lead to the formation of liquid CO₂ (Figure 11).

Sequestration

A number of potential methods to sequester CO₂ are discussed, such as carbonization, but it seems the use of natural underground reservoirs will be key among these options [14,17,18] .

Table 2: Natural reservoirs suitable for CO₂ storage -1990 estimate [19]

| Storage option | Global capacity, Gt CO ₂ | % of emissions to 2050 |
|-----------------------------|-------------------------------------|------------------------|
| Depleted oil and gas fields | 920 | 45 |
| Deep saline reservoirs | 400-10000 | 20-500 |
| Un-mineable coal measures | >15 | >1 |

CO₂ can also be used for enhanced oil recovery, by injecting CO₂ into oil fields, either by miscible , water-alternating gas injection, (where CO₂ is injected alternatively with water) or immiscible (to increase or maintain reservoir pressure) technologies. CO₂ is also considered for enhanced gas recovery in gas fields [2,17]. Injection pressure is a function of injection depth. As a benchmark, for 800 m depth, the reservoir pressure is about 75 bar, and for deeper reservoirs, CO₂ will be supercritical (Figure 13). Known CO₂ injection applications operate in the dense phase area. The examples shown in Figure 14 in the Sleipner reservoir, the CO₂ cools down, but it heats up at In-Salah and Snohvit . Snohvit and Sleipner are off-shore, while In-Sah is an on-shore site. Reservoir depth below the seafloor or surface, respectively, is 700 m (Sleipner), 1700 m (In Salah) and 2400 m (Snohvit)[6].

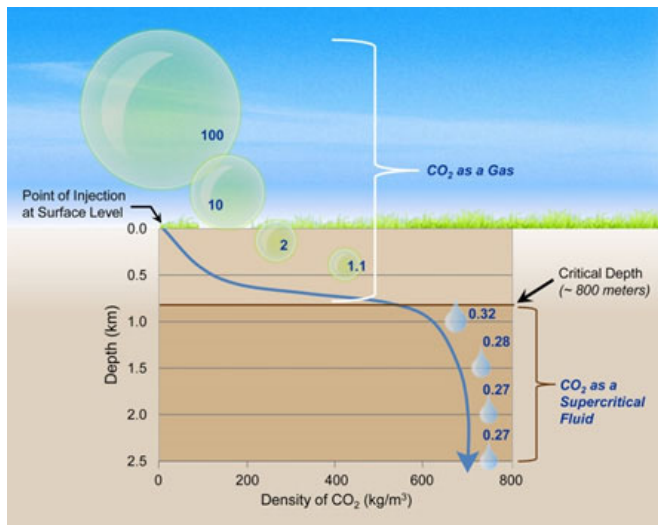


Figure 13: CO₂ density as a function of storage depth. CO₂ reaches supercritical pressure and volume at about 800 m depth.[19]

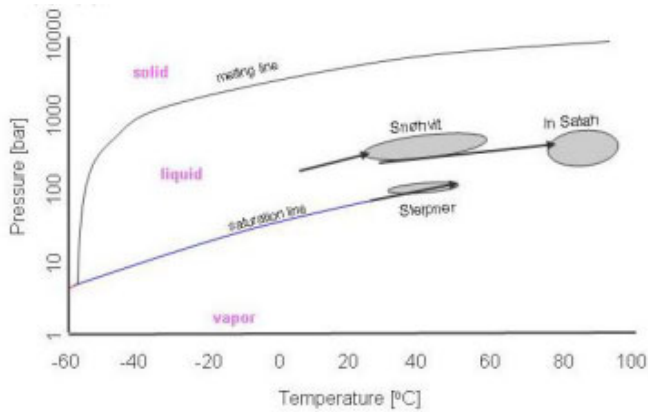


Figure 14: Phase diagram of pure CO₂ and well head and bottom hole conditions (arrows), reservoir conditions (shaded areas) for 3 sequestration sites (Sleipner, Snohvit and In-Salah)[6].

HYDROGEN

Hydrogen as a means of energy transport and storage is part of the discussion to reduce the societal carbon footprint. Figure 15 outlines the different transportation pathways for hydrogen. Hydrogen can be produced near sources of renewable energy (green hydrogen, for example via electrolysis), near sources of natural gas (blue hydrogen for example via steam methane reforming, cyan hydrogen for example via pyrolysis), or near the locations of hydrogen demand (blue hydrogen, cyan hydrogen).

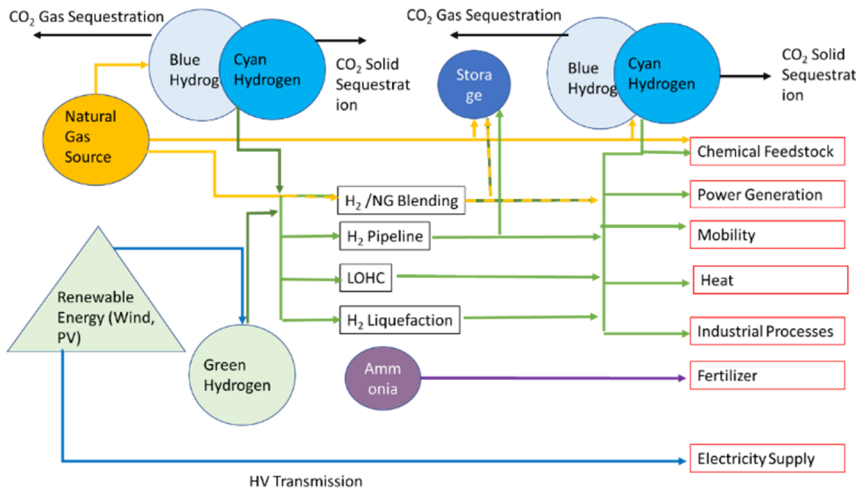


Figure 15: Transportation pathways for hydrogen

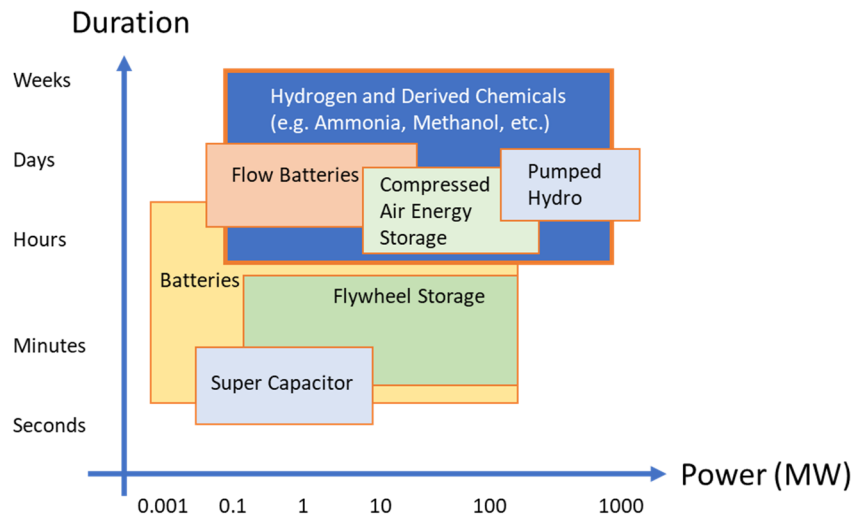


Figure 16: Comparison of energy storage concepts suitability based on storage duration required and amount needed [3,5]

In all cases where hydrogen is generated from fossil fuels, the resulting CO₂ would have to be captured and sequestered. In the cases of gaseous (or liquid) CO₂, this would require CO₂ pipelines to transport the CO₂ to sequestration sites.

A few basic facts about hydrogen are relevant for this discussion, and are repeated here:

- Hydrogen is not a primary energy source, so it has to be generated
- The combustion product of hydrogen is water (and possibly NO_x)
- Hydrogen has a high energy density by mass and a low energy density by volume
- Hydrogen has a low density, i.e. a low specific gravity
- Hydrogen has a high speed of sound

Sources of hydrogen can be chemical plants and refineries that produce hydrogen as a by product, or purpose generated hydrogen that is created by processes like steam reforming of methane, electrolysis, or pyrolysis. Some of these processes, like steam reforming of natural gas, will create CO₂. To be carbon neutral, the CO₂ has to be captured and sequestered.

Generally, the transportation and storage pathways for hydrogen are outlined in Figure 15. Hydrogen can be transported as a gas, either as more or less pure hydrogen in pipelines, or by mixing it into natural gas pipelines. It can also be transported as a liquid, via LOHC (Liquid Organic Hydrogen Carriers), as Ammonia (NH₃), or as liquefied hydrogen. These modes of hydrogen transportation compete with energy transport by natural gas, or via High Voltage Electric Power Lines. Considerations involve the question whether, at the end point, hydrogen is needed as a molecule, or whether electricity is desired.

As we will see, transporting energy as natural gas is more efficient than transporting hydrogen as a gas, or electricity. LOHCs seem attractive, especially if hydrogen is to be delivered across large distances, akin to LNG. Transporting liquid hydrogen is also very attractive, but the energy cost for cooling hydrogen to a liquid state is extremely high. The energy cost of making hydrogen from natural gas, but especially from electricity, is significant (Allison et al. [3]). Because transport of CO₂ or natural gas in pipelines requires less energy than transporting hydrogen, it may be advantageous to locate Steam Methane Reformers close to the usage point of the hydrogen, and transporting the feedstock (natural gas) to that location and the resulting carbon (CO₂, or in the case of pyrolysis the carbon dust) to a sequestration site.

On the other hand, hydrogen allows energy storage at a large scale (either in the pipeline itself, or in gas storage facilities). In a carbon neutral world, all energy has to be either from renewable sources, or from sources where the CO₂ resulting from the use of hydrocarbons is sequestered. Many renewable sources of energy, like wind power and photo voltaics (PV) produce energy at a fluctuating rate. Therefore, means of storing and releasing electricity are important to be able to meet the consumers' electricity demands (Figure 16). Hydrogen and derived chemicals allow both the storage of large amounts of energy, and also allow this storage for long durations. It should be noted that hydrogen is already a valuable feed stock in the refinery and chemical industry.

Questions in this context include:

- Is the transport of electricity more efficient than the transport of hydrogen?
- At the receiving end, is the hydrogen used
 - as fuel to create electricity?
 - for transportation (trucks, cars or planes)?
 - as a feedstock (see above)?
 - for heating purposes where traditional fuels like natural gas are hard to replace (for example, steel production)?

Hydrogen “colors” colloquially refer to the way the hydrogen is generated, and so we have a rainbow of colors including some colors, like brown, grey and black, that are not part of the rainbow [20]. For the most part, turbomachinery that either utilizes or transports hydrogen doesn't care where and how the hydrogen originated, but it is still important to understand the basic nomenclature.

Green hydrogen is produced without any greenhouse gas emissions. It is made by using electricity from renewable sources, like photovoltaics or wind power, to electrolyze water. Electrolyzers use an electrochemical reaction to split water into its components, hydrogen and oxygen.

Blue hydrogen is produced from natural gas using a process known as steam reforming, where natural gas and steam react to form hydrogen, but also carbon dioxide. To make hydrogen “blue,” the carbon dioxide must be captured and sequestered. If the same process is used, but the carbon is not captured, we call the gas *grey* hydrogen.

Black and *brown* hydrogen are made through partial oxidation gasification from black coal or brown coal (lignite). This is the type of hydrogen that creates the largest amount of environmentally damaging by-products.

Red (also known as *pink* or *purple*) hydrogen is generated using electricity from nuclear energy. Just like green hydrogen, an electrolysis

process is used. The difference is that the nuclear waste is created as a by-product of these processes. There are also some ideas to use the high temperature reactors or available steam.

Turquoise (or *cyan*) hydrogen is made by a process called methane pyrolysis. The by-product is solid carbon. Depending on the thermal process that is used for pyrolysis — for example, whether it comes from renewable sources — and the capability to store the solid carbon permanently, this can be a low- or no-carbon process.

Yellow hydrogen is produced by electrolysis directly from solar energy without the intermediate step of creating electricity. In some publications, the term ‘yellow’ hydrogen is used when the electricity for the electrolysis process comes from multiple sources, some of them renewable, some of them conventional.

And lastly, *white* hydrogen is naturally occurring geological hydrogen. There is indeed a process that involves drilling a hole in the ground to get to hydrogen, with some fracking involved; however, there is currently no large-scale exploitation of this relatively rare resource.

Why are the “colors” of hydrogen important, especially since the machinery is agnostic to its source? There are two aspects where the production source can make a difference: the pressure at which the hydrogen is available and the composition of the hydrogen gas. Both relate to the fact that hydrogen compression is very energy intensive. For a given mass flow, the amount of work to get a certain pressure ratio with pure hydrogen is almost 10 times higher than that of natural gas. Of course, hydrogen has a much higher energy density on a mass basis than natural gas (the lower heating value of hydrogen on a mass basis is 2.5 times that of natural gas), but even for the same energy flow, the compression work for hydrogen is four times higher.

On the other hand, even a small amount of composition impurity of the hydrogen, such as 4-5% carbon dioxide, can substantially lower the compression work by a factor of two. Therefore, it makes a big difference at what pressure and composition the hydrogen is made available in various compression processes. Also, both the combustion characteristics and the compression work change if other components (such as carbon dioxide or methane) are part of the hydrogen produced. Lastly, the capability of hydrogen to cause material issues (such as hydrogen embrittlement) can be influenced by the presence of other substances in the gas composition.

A third consideration of the source of hydrogen has less to do with the gas itself and more with the by-products of its generation process. Specifically, in processes that produce hydrogen from fossil fuels, carbon dioxide usually also is generated. For example, if blue hydrogen is produced from natural gas using steam reforming, about 4.5 kg of carbon dioxide are produced for every kilogram of hydrogen. In these cases, the separation, transport and sequestration of carbon dioxide is necessary to maintain greenhouse gas neutrality — and that requires additional compression infrastructure [21].

While green hydrogen uses electrolysis or similar process to create hydrogen from water, blue (and grey) hydrogen use natural gas as feedstock. Thus, blue hydrogen generation would still require the transport of natural gas in pipelines, because from a transportation cost perspective, it is more effective to transport natural gas than hydrogen. Therefore, the hydrogen production would preferably be close to the user of the hydrogen. It is worth studying whether the subsequent transport of CO₂ to sequestration sites could alter this statement.

Laughlin in [5] found that blue hydrogen, adding the cost for today’s carbon sequestration technology, has a cost per energy unit (per kJ) comparable with gasoline or diesel. The attractiveness would be also determined by the amount of carbon taxes. In such a scenario, green hydrogen would likely be noncompetitive as long as there are sufficient supplies of fossil fuels, and sufficient and convenient sequestration sites. This is due to the fact that green hydrogen is made from electricity. Scenarios where blue hydrogen would make renewable energy uncompetitive, including storage requirements, are possible. If blue hydrogen is generated (or CO₂ is removed from the exhaust stream of fossil fired engines), this CO₂ has to be compressed to about 140 bar for transport in a pipeline to a sequestration site.

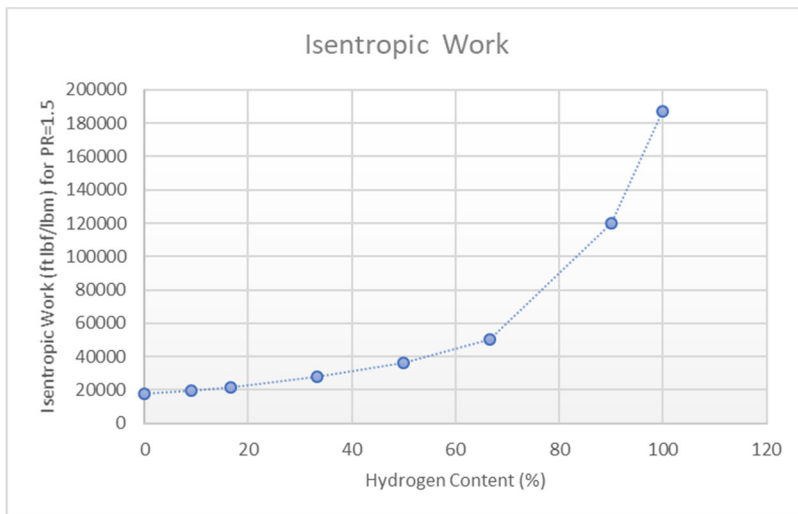


Figure 17: Isentropic work required for a pressure ratio of 1.5, depending on the amount of hydrogen added to typical pipeline quality natural gas [16].

Hydrogen Compression

Hydrogen is a very light gas with a high heat capacity, and a very high speed of sound (Table 1). Given the thermodynamic properties of hydrogen, a certain amount of work creates a certain pressure ratio and a certain amount of volume reduction that are less than for other gases such as natural gas, air or CO₂. Hydrogen compression will see both reciprocating and centrifugal compressors. A key difference in the working principles of centrifugal and positive displacement machines is that centrifugal ('dynamic') compressors create head (i.e. the head is directly related, via Eulers law, with the energy exchange and the changes in velocities in the compressor), and head translates into pressure ratio as a function of the gas composition. For light gases (such as hydrogen), even a large amount of work input (head) translates into only little pressure ratio (Figure 17).

Reciprocating compressors, on the other hand, create volume reduction and pressure ratio due to their geometry. This does not mean that their efficiency is automatically higher, it only means that one needs fewer stages to get the required pressure ratio. Since the power consumption is only determined by mass flow and head, there is no inherent advantage of reciprocating compressors as far as power consumption is concerned.

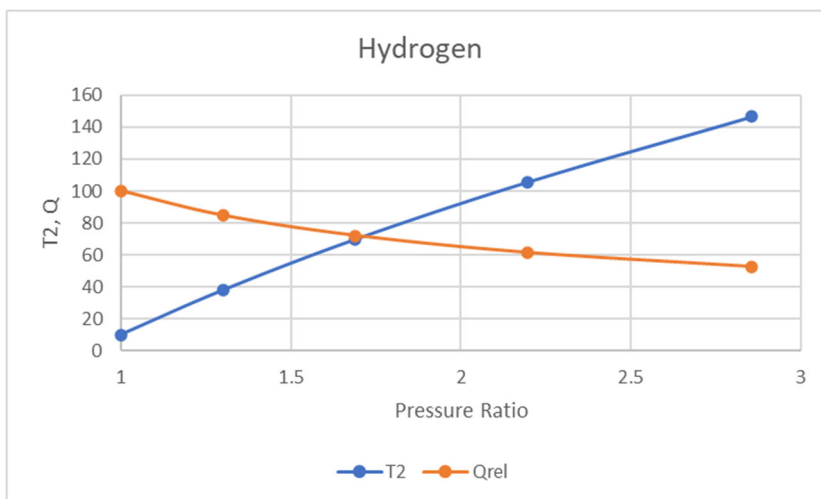


Figure 18: Discharge temperature (°C) and volume reduction in Hydrogen compression. No intercooling.

Especially for lower flows and very high pressure ratios (such as required at filling stations for hydrogen powered trucks), reciprocating compressors are favored. However, for high flow and high power applications, the higher power density that can be achieved with centrifugal compressors might prove advantageous. Avoiding lube oil contamination of the compressed hydrogen is a challenge for reciprocating machines.

For centrifugal compressors, methods need to be found to increase the amount of work per compressor stage, or per compressor body. This can be accomplished by combinations of higher tip velocities, less backsweep, increasing the 3rd critical speed of the rotor, and more stages per compressor body (a stage is an impeller with its inlet system and its diffuser). Mach number limitations are generally

not an issue due to the high speed of sound in hydrogen (Table 1). In this tutorial, the compression requirements for liquefying hydrogen will not be addressed.

Figure 18 identifies a key difference between hydrogen compression and CO₂ compression (compared, for example to Figure 6). Hydrogen compression, even for very high work input (The highest pressure ratio in Figure 18 would correspond to about 1500 kJ/kg (500,000 ftlb_f/lb_m)) will lead to very modest increases in temperature, and small volume reductions. Frequent intercooling is therefore not critical (although useful). The relatively small volume reduction also does not require the massive speed increase for rear compression stages as seen for CO₂ compression.

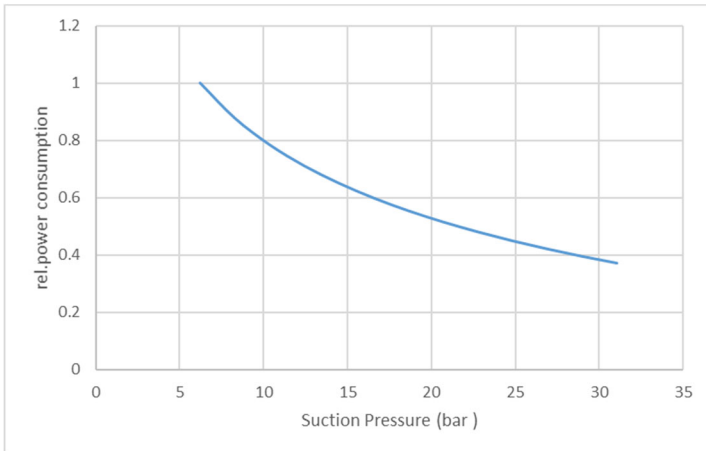


Figure 19: Compression power as a function of hydrogen supply pressure. Discharge pressure 102 bar .

If hydrogen is considered a viable means of transporting energy, then there are number of steps where compression is required. Depending on flows and pressure ratios, centrifugal compressors compete with reciprocating compressors. Another question is whether these compressors are driven by combustion engines or electric motors. The applications are as follows:

- 1- Compression from the electrolyzer to pipeline pressure (green hydrogen). This would require machines to get from about 20 bar to pipeline pressure, say at 80 to 100 bar. It may be possible to build electrolyzers that produce hydrogen at pipeline pressure, thus avoiding the need for compression. Compression from a Steam Methane Reforming process (blue hydrogen), the compression requirements are similar as for green hydrogen (Figure 19)
- 2- Boost compression in a pipeline. If the pipeline has to cover a longer distance, pipeline compressor station will be needed in regular intervals, with the intervals probably similar to natural gas pipelines. The gas to be compressed can be natural gas mixed with hydrogen from 0 to 100% hydrogen content, and most likely a fluctuating hydrogen content due to the fluctuating availability of renewable electricity. [3,22,23] have provided calculations showing how varying hydrogen content affects power consumption and head requirements for the compressors, and the impact on transportation capacity of existing pipelines (Figure 20).
- 3- Storage compression. Given the rationale for hydrogen generation, it is likely that hydrogen or hydrogen natural gas mixtures will be subject to longer term storage in aquifers, depleted gas fields and salt caverns, assuming they are able to contain hydrogen. Pressure ratios for the compressor will be from pipeline pressure (say 80 to 100 bar) to storage pressure which could be as high as 200 or 300 bar.
- 4- Fuel gas compression, and similar. At the delivery point of the pipeline, it may be required to separate natural gas and hydrogen, particularly at higher hydrogen concentrations (to allow appliances to continue operating), or if pure hydrogen is needed. The process will cause a pressure drop, and compression is needed, for example to bring the hydrogen to the necessary fuel gas pressure for a gas turbine (say, 20 to 30 bar), or to the required pressure for truck fuel (say 700 to 900 bar).

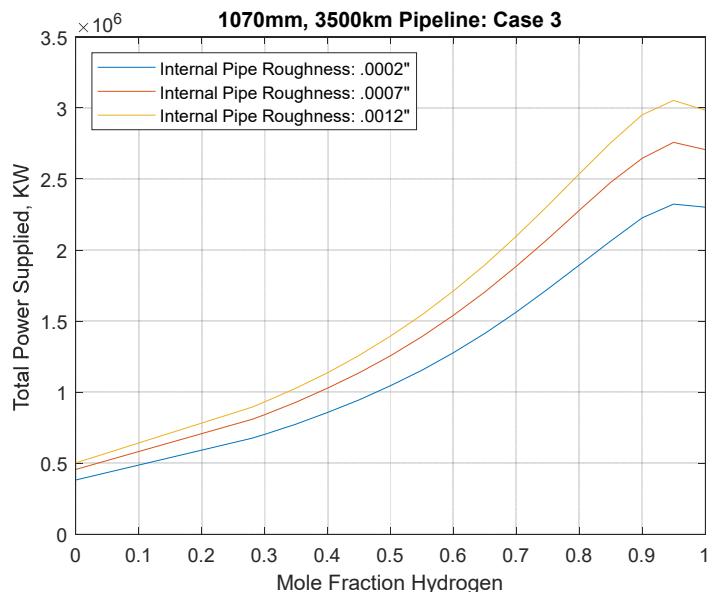


Figure 20: Hydrogen blending increases compression work. Note that the increase in power demand is only valid for this particular example. Other examples will lead to different results but will show generally the same trend [3].

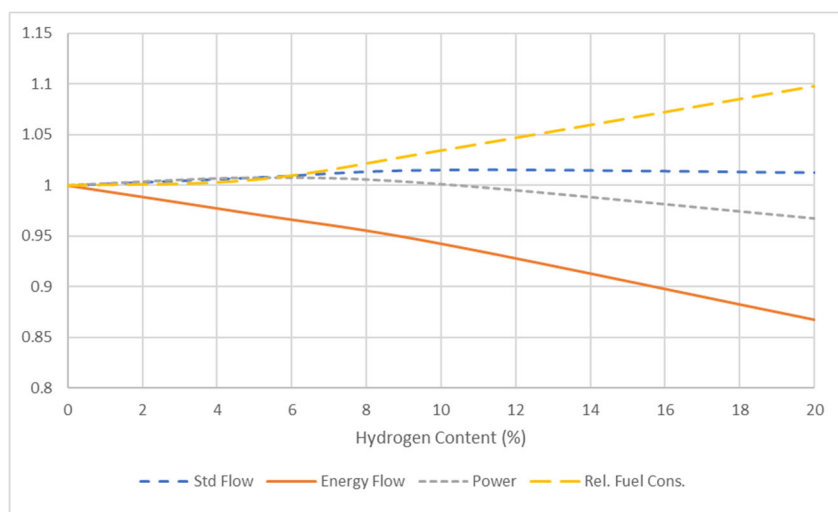


Figure 21: Result of adding hydrogen into a natural gas pipeline: Energy flow, standard flow, power and relative fuel consumption (fuel consumption per energy delivered) when hydrogen is added to natural gas, normalized by the respective parameters at 0% hydrogen content [22].

If hydrogen is mixed with natural gas, and transported in a natural gas pipeline, existing infrastructure is capable to accommodate a certain amount of hydrogen. The capability is limited by material concerns (for example due to hydrogen embrittlement), by the capability of end users to handle certain amounts of hydrogen, and by the capability of the machinery involved. Kurz et al. [22] have analyzed pipeline behavior when low amounts of hydrogen (up to 20% by volume) are added to an existing pipeline, consisting of multiple compressor stations. Adding hydrogen to an existing pipeline increases the compression work, as well as the total power consumption in the pipeline (Figures 19, 20, 21). Therefore, the transport capacity of the pipeline in terms of energy flow will be reduced (Figure 21). The transport capacity can be limited by either the maximum speed of the compressors, or the available power of the drivers. For the example in Figure 21, the power demand is increased up to about 7% hydrogen content, and then starts to drop, because the driven compressors reach their speed limit. The pipeline operator then can decide to re-stage the compressors to provide more head, and to add compression trains to increase the available power per compressor station. In the scenario described, if the hydrogen is produced from renewable energy, it would be highly likely that the hydrogen content in the natural gas would fluctuate.

Dry Gas Seals

Dry gas seals have been used successfully in hydrogen applications, and the working principles of dry gas seals should not be affected by the presence of hydrogen [5]. The large pressure drops typically occurring in seals and filters, require attention, as hydrogen gas, subjected to an isenthalpic pressure drop, will increase its temperature, and not, like most other gases, drop in temperature. Another issue that has to be addressed when compressing and transporting hydrogen is the contamination with lube oil. Centrifugal compressors with dry gas seal prevent any contamination of the process gas.

If air is used as a separation gas (between the bearing and dry gas seal) avoiding explosive mixtures in the secondary seal vent due to the wide range of flammability of hydrogen-air mixtures has to be considered. Further, material selections, and limitations of design yield strength have to be evaluated.

TRANSPORTATION

One of the questions in the discussion on carbon reduction relates to the energy requirements for the transport of the gas involved, ie natural gas, CO₂ and hydrogen. To answer the question, pipelines for the transport of these gases are simulated.

Hydrogen Pipeline

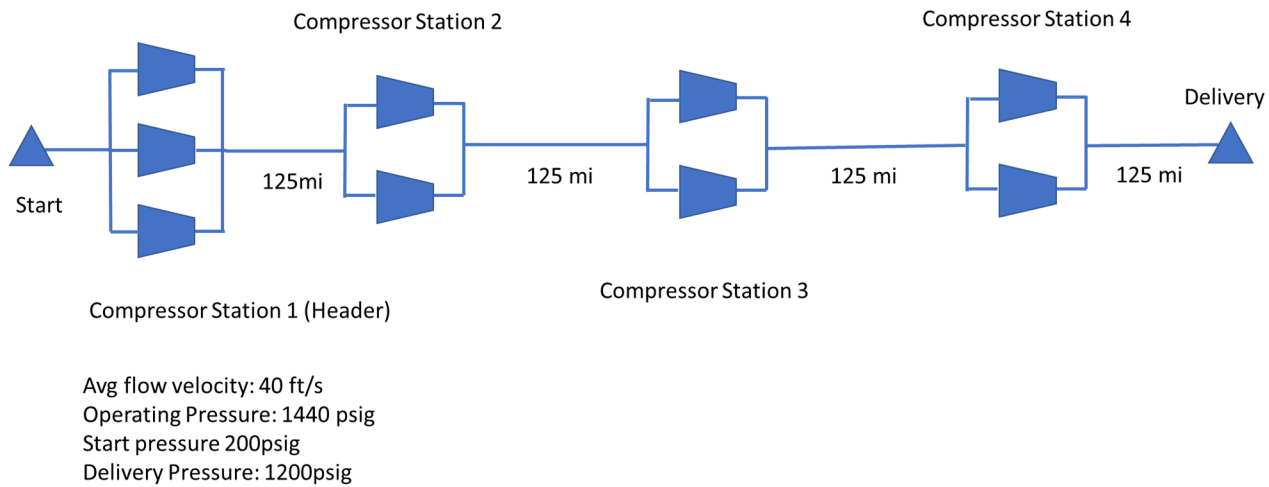


Figure 22: Hydrogen pipeline, 500 miles (800km) , 1000 MMSCFD

CO₂ Pipeline

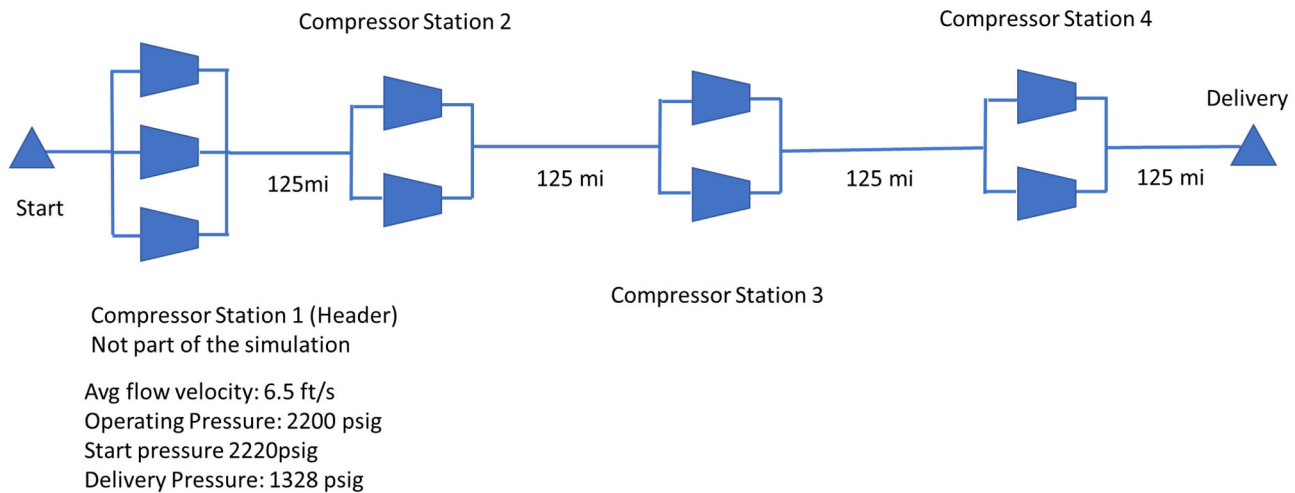


Figure 23: CO₂ pipeline, 500 miles (800km), 1300 MMSCFD, 100 °F (37.8 °C)

The simulations include:

1- A dense phase CO₂ pipeline with 32'' nominal diameter, 3 compressor stations equally spaced, transporting about 766 kg/s or 1300 MMSCFD, for a distance of 500 miles (800 km). The operating pressure is 2200 psig, and the inlet pressure for the compressor station is kept at above 1320 psig (91 barg) to avoid two-phase flow at all prevailing ambient temperatures. The calculations shown are for 37.8 °C (100 °F) gas temperature at the head station discharge.

2- A hydrogen pipeline for the same distance (500 miles, 800 km), 1440 psig (99 barg) operating pressure, transporting 1000 MMSCFD, also with 3 compressor stations equally spaced.

3- A 500 miles (800 km) natural gas pipeline, for 700 MMSCFD, 1440 psig (99 barg) operating pressure, natural gas with SG=0.58.

It should be noted that the power consumption of the header station is very large relative to the pipeline stations both for the CO₂ and hydrogen cases. This power consumption is very sensitive to the suction pressure, which could be as low as atmospheric pressure for CO₂, or as low as 5 bar for hydrogen (Figures 6 and 19). The results are summarized in Table 3.

Table 3: Summarized results for the pipeline simulations

| Gas | Flow (MMSCFD) | Station PR | Head (kJ/kg) | Power (kW) |
|-----------------|---------------|------------|--------------|------------|
| Hydrogen | 1000 | 1.21 | 238.9 | 7946 |
| Natural gas | 700 | 1.45 | 50.8 | 9909 |
| CO ₂ | 1300 | 1.65 | 6.55 | 6182 |

The head and power requirements outlined in Table 3 would require a 7 to 8 stage centrifugal compressor, with 585 mm (23 in) diameter impellers for hydrogen, while the CO₂ application can be covered with a single stage compressor with a 380 mm (15 in) impeller. The natural gas compressor would require a single impeller or two impellers, typical diameter would be 530 to 560 mm (21 to 22 in).

To operate a 1 GW power plant, 600 MMSCFD of hydrogen, or 180 MMSCFD of natural gas are needed, and 162 MMSCFD CO₂ are produced. To be able to compare the power consumption based on the flows related to the operation of a 1 GW power plant, the flow from Table 3, and with it the power consumption, is scaled to the flow for a 1 GW power plant, and shown in Table 4

Table 4: Summarized results for the pipeline simulations, corrected to 1 GW plant flow

| Gas | Flow (MMSCFD) | Station PR | Head (kJ/kg) | Power (kW) |
|-----------------|---------------|------------|--------------|------------|
| Hydrogen | 600 | 1.21 | 238.9 | 4768 |
| Natural gas | 180 | 1.45 | 50.8 | 2548 |
| CO ₂ | 162 | 1.65 | 6.55 | 770 |

In Table 4, the data is shown by scaling the pipeline to the flow required for a 1 GW power plant, to be able to compare power demands. The pipelines themselves would probably be too small to be economic. This was the reason why the pipeline flows in Table 3 were used.

The data in Table 4 and Figure 16 show the significant difference in consumed power in these cases. It becomes clear that for a power plant of a given size, transporting hydrogen to the plant requires more energy than the transport of natural gas to the plant, and the transport of CO₂ from the plant. Table 4 indicates that even if the power for the Natural gas and the CO₂ pipeline are combined, they are still significantly lower than the power for the hydrogen transport. Bringing natural gas to a power plant and transporting the generated CO₂ to a sequestration site is more energy efficient than transporting hydrogen, generated elsewhere over larger distances.

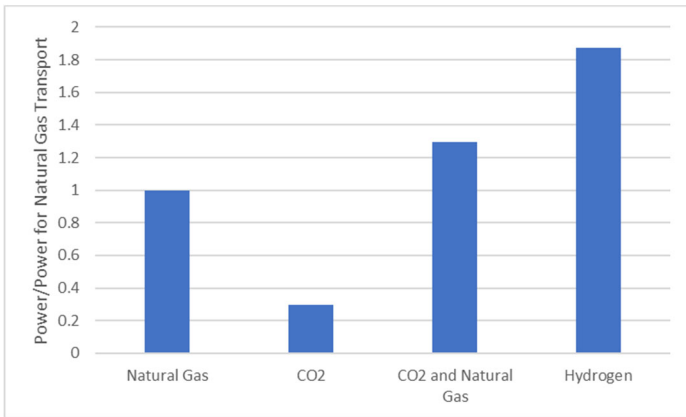


Figure 24: Relative power requirement for transportation of CO₂ and Hydrogen, compared to transportation of natural gas.

STORAGE

Storage of gases in geological formations is well established for natural gas storage and for CO₂ sequestration, and it is under discussion for hydrogen storage [5,14,25]. Concerns include the question whether formations that are gas tight for natural gas are also capable of retaining the much smaller hydrogen molecules, and the question whether hydrogen-natural gas mixtures would get stratified.

Depleted natural gas or oil fields, often close to consumption centers are frequently used for storage. Conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections. Depleted oil and gas reservoirs are the most commonly used underground storage sites for natural gas due to their wide availability. Natural aquifers have been converted to gas storage reservoirs. An aquifer is suitable for gas storage if the water bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be enhanced by the presence of an active water drive.

Salt caverns provide very high withdrawal and injection rates relative to their working gas capacity. Base gas requirements are relatively low. Cavern construction is more costly than depleted field conversions when measured on the basis of cost per working gas capacity, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each thousand cubic feet of gas injected and withdrawn.

There also have been efforts to use abandoned mines to store natural gas, with at least one such facility having been in use in the United States in the past. Further, the potential for commercial use of hard-rock cavern storage is currently undergoing testing. None are commercially operational as natural gas storage sites at the present time. Other large scale storage concepts include contained membranes [25]. The storage pressures would be in the range of 100 to 200 bar, or higher, thus requiring significant amounts of compression. Compression to inject the CO₂ into the storage facility brings the CO₂ from delivery pressure (20 to 150 bar) to injection pressure. Depending on the type of storage facility, the required injection pressure could be 200 bar (3000 psi) or less in abandoned gas fields, below about 250 bar (3750 psi) in aquifers. Injection for enhanced oil recovery (EOR) could be 200 to 400 bar or higher (Figures 13 and 14). The flow demand is to some extent determined by facility limitations (for example, erosion limits).

CONCLUSION

This tutorial discussed the applications that require gas compressors in the context of decarbonization efforts. It focuses on three different gases that need to be compressed in this context: Hydrogen, natural gas and CO₂. One of the key concepts is that the uses of these three gases is closely related. Requirements for these applications are analyzed and explained.

Starting with CO₂, and following its path from capture, through transport in pipelines to its sequestration, we highlight the tasks related to the required very high pressure ratios, and the operation in dense phase and supercritical conditions. While CO₂ compression, allowing high pressure ratios in a machine, often makes intercooling advantageous. Limitations come from typically high machine Mach numbers, and from the rotordynamic challenges of potentially high density. Operation in the super critical or dense phase regime may be required.

On the other hand, hydrogen, a very light gas, requires significant more work than natural gas or CO₂ to achieve required pressure ratios, but generally does not involve high Mach numbers. The transport of Hydrogen in pipelines is thus very energy intensive.

We provide insight in the questions around the use of blue hydrogen, green hydrogen or carbon capture from fossil fired power plants.

The transport of CO₂, hydrogen, or natural gas over equal distances, based on a 1 GW power plant, indicates that the transport of hydrogen is more energy intensive than the transport of natural gas to the power station and the transport of CO₂ away from said station to a sequestration site.

The intent of the tutorial is to provide data for decisions on various discussions in the field of carbon reduction measures.

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