COMPRESSOR APPLICATIONS IN THE DECARBONIZATION DISCUSSION

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Abstract - The emphasis on reducing the carbon footprint has led to efforts to use hydrogen and to decarbonize when fossil fuels are used. This creates a variety of new applications for gas compression: When hydrogen is generated, it must be compressed to the pressure needed in a pipeline, an engine or another user. In pipelines, hydrogen natural gas mixtures or pure hydrogen must to be compressed in booster stations. In the field of carbon capture, sequestration and usage, we find compressors to bring the captured CO2 to pipeline pressure, we have booster stations to compress it, and compression may be needed to sequester the CO2 in underground storage sites. Many, if not most, of these gas compressors are driven by electric motors. Given the foreseeable fluctuation in operating conditions, many of these will require variable speed motors. The paper will target the areas for carbon capture, transport and sequestration, and the topic of compression and transport of hydrogen.

Index Terms: Carbon Reduction, Carbon Dioxide, Hydrogen, Carbon Capture, Compressors,

I. INTRODUCTION

Greenhouse gas reduction hinges on the use of hydrogen, as well as CO2 avoidance, capture and sequestration [1,2,3]. For both applications, gas compression is necessary. The gas compression requirements associated must 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. Further, the discussion of drivers for these compressors must be addressed. In the case of CO2, the gas cannot be used as a fuel, as it has no heating value. hydrogen can be used as fuel, but in many instances, electric drives are economically advantageous.

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):

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

where p_1 and p_2 are inlet and discharge pressure, respectively, η is the efficiency, c_p the heat capacity, T_1 the inlet temperature, H the work, and γ the ratio of heat capacities for the compression process.

TABLE 1
Thermodynamic Properties

	Hydrogen	Natural Gas	CO2
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

With the relevant properties in Table 1, we can see that the pressure ratio achievable with the identical amount of work will be vastly different. Further, while the speed of sound for CO2 is low, it is higher for natural gas and highest for hydrogen, which is important for the compressor aerodynamics as outlined later.

II. CARBON DIOXIDE

CO2 is a relatively heavy gas with a low speed of sound (280 m/s), 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 large volume reduction per stage but they 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 large flow 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 [4].

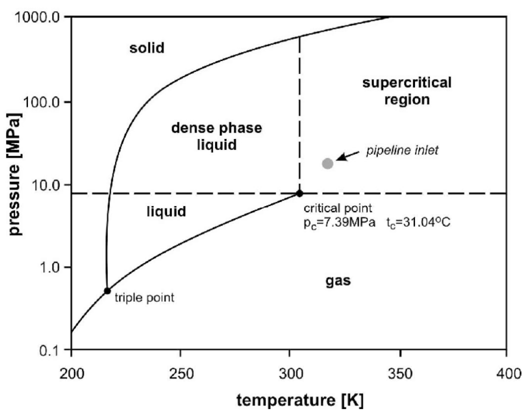

Fig. 1 CO2 phase envelope [5]

The thermodynamic concept of compressing or pumping CO2 must 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 is 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). CO2 under these conditions still behaves like a gas, as it is compressible and fills available space and has a low viscosity, which makes the pipeline transport in the supercritical phase attractive.

Operating conditions for pipelines and for sequestration tend to be in the range of supercritical or dense phase regions for CO_2. 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. They do, however have a very strong sensitivity of the density to temperature changes. This is a challenge for any compressor or pump [6,7].

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

1-After capturing the CO2 from the exhaust of a fossil fired plant, from creating blue hydrogen, or from the production of ammonia, 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 we 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.

2-If the CO2 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 application above. However, the subsequent disposal follows the same rules. Since the capture of the CO2 may be part of offshore, deep water operations, and the CO2 may be used to promote enhanced oil recovery (EOR), high discharge pressures (over 400 bar are known) are frequently required.

3- The captured CO2 must 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 flow capacity of a pipeline.

4- Once CO2 is captured, and available with some impurities, it has to be sequestered, either by using it for enhanced oil or gas recovery [8], or by storing it 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 maybe anywhere from 100 bar to 500 bar. Other options, such as mineral carbonization, have been proposed, but will not be addressed in this paper. It may be advantageous to gather the CO2 production from several sites within a certain distance from a hub, and, at the hub compress this CO2 to sequestration pressure. The pressure at such a hub would typically be significantly above atmospheric pressure.

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]. The GERG-2008 EOS performs well, while the BWRS EOS shows large deviations in the calculation of critical pressure and temperature [2].

A. CO2 Capture Compression

After capturing the CO2 from the exhaust of a fossil fired plant, from creating blue hydrogen, or from the production of ammonia, it has to be compressed either to a pressure that allows for the sequestration of the gas (the pressure can vary between 100 and 500 bar, depending on the geological formation for the sequestration), or to a pressure that is required for efficient transport, for example in a pipeline (typically 140 bar or above). Generally, the CO2 will be available at low pressures, often near atmospheric pressure. The same is true for CO2 from cement or ammonia production [4].

CO2 from exhaust gas capture usually contains certain amounts of water (typically about 0.14% by mole), and other impurities like H2S, CO, O2, CH4 (and higher alkanes), nitrogen, ammonia, argon, hydrogen, SOx, and NOx, dependent on the type of fuel used, the type of machinery and the methods for NOx emission reduction.

Oxyfuel combustion will yield significant levels of argon (5.7 mole %), oxygen (1.6 mole %), NO (0.25%) and nitrogen (0.06%) [2]. CO2 from Steam Methane Reforming (SMR) processes (for the generation of blue hydrogen) will contain hydrogen (1.7 mole%), nitrogen (0.03 mole%), methane (0.035 mole%) and CO (appr. 1.7%) [2]. The water will have to be removed during the compression process, because liquid water with CO2 forms carbonic acid, which corrodes materials. Of the other contaminants, 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.

In this section, the discussion will be about the compression process, and the compression power required to bring carbon dioxide from supply pressure to a reasonable pipeline pressure (140 bara). A comprehensive study of compression options [9] highlights the advantage of a semi-isothermal compression, that is compression with cooling after every stage.

The compression work is defined as power consumption per unit of mass flow. To increase the pressure from 1 bar to 140 bar economically 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. 10 stages of compression would require about 26 kJ/kg of head, with subsonic flow, while 6 stages of compression would be at 50kJ/kg of head [4].

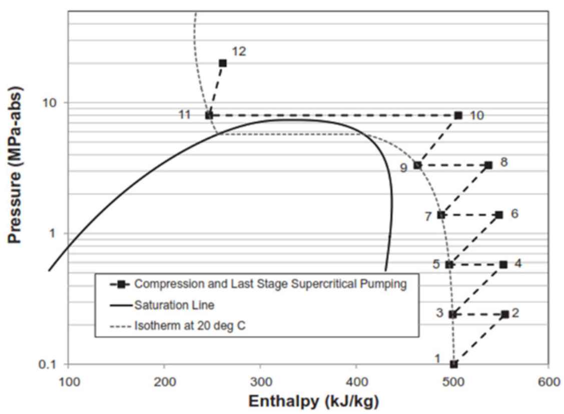

Fig. 2 Compression of CO2 (Mohitpour et al.,[2])

The impact of inlet pressure on power consumption and compressor size is significant (Figure 3). Compression from atmospheric conditions to 140 bar require between 5 and 8 stages of compression, with a subsequent compression stage in the dense phase region (Figure 2, step 11 to 12) . The significance of the dense phase compression 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. The results also point to a significant power reduction if the CO2 can be delivered at higher pressures.

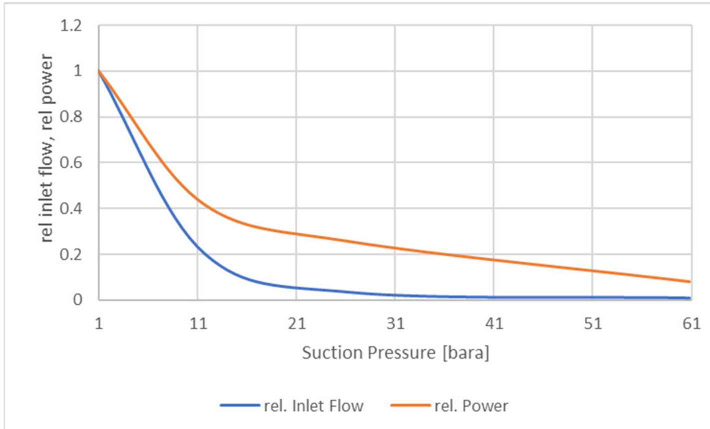

Fig. 3 Impact of inlet pressure on power consumption and inlet flow. Discharge pressure 140 bar, intercooled solution

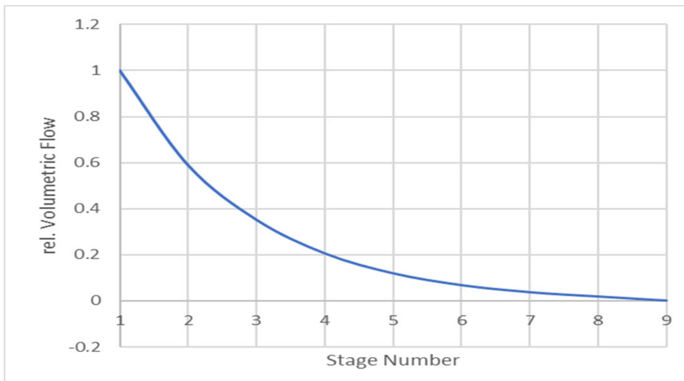

Fig 4 Flow reduction due to compression for 8+1 stages. Volumetric flow is reduced by a factor of over 300 from inlet to outlet of the compressor.

Figures 3 and 4 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, the massive volume reduction would lead to very small impellers in the final stages.

When sizing the compressors it must be considered that the compressed gas may not be pure CO2, 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 [4].

B. Pipeline transport

The prospective areas for CO2 sequestration will likely be at some distance from large sources of CO2 production (IPCC, [10]). In many areas, the sequestration sites may be offshore. This indicates the need for CO2 transportation solutions.

While CO2 can be transported in pipelines over a wide range of pressures, transport in the dense phase region has several advantages: While CO2 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. Unlike gas in the subcritical range, there is no phase change when it is cooled.

A few things need to be considered [4]: While elevation changes in natural gas pipelines are only responsible for secondary effects, in dense phase CO2, elevation changes lead to significant changes in gas pressure. Therefore, pipeline must be sized such that under all operating conditions and operating temperatures, the CO2 pressure stays above 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 CO2 in dense phase raise the question whether pumps or compressors can be used in this application (Figure 5). CO2 in dense phase is compressible, and there are no phase changes. The duty can thus be handles efficiently both by compressors and pumps.

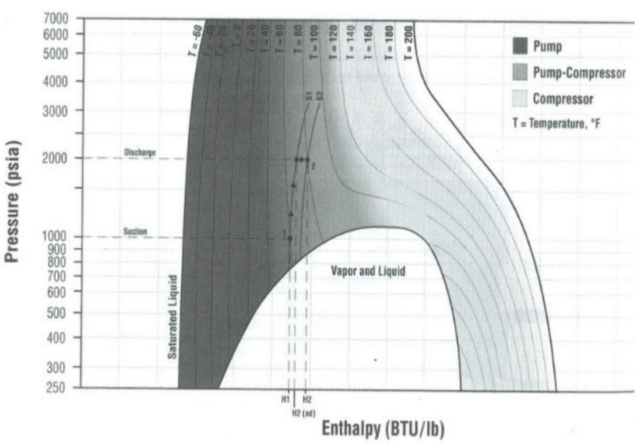

Fig. 5 Pipeline transport of CO2 in dense phase [2].

Existing CO2 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 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 [11]. 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 place about 150 to 250 km apart, thus requiring a pressure ratio of about 1.5.

Calculations, using commercially available pipeline simulation software show that for a 30in (760mm) diameter pipeline, flowing 1300MMSCFD of CO2 modelled after an existing CO2 pipeline in [12] show a pressure drop from 152 bar to 90 bar, after a distance between stations of 210km (130 miles). No elevation changes were simulated. The power consumed for recompression from 90 bar to 152bar is 8550 kW (11500hp) with a single stage centrifugal compressor, running very slow (Machine Mach Number 0.5) 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 [4].

Since the CO2 to be transported will not be pure, the impact of impurities must be considered. 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].

While CO2 transport in dense phase requires the least amount of energy, lower pressures may be considered, even though the power consumption for the transport will increase. Lower pressure pipelines are considered for 2 reasons: (1) The transport is for a relatively short distance or (2) Existing pipelines with a lower pressure rating (for example natural gas pipelines with a typical pressure rating of about 105 bara) are to be used, to avoid the requirement for new pipeline construction.

C. Sequestration

Several 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 [13].

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TABLE 2
Natural reservoirs suitable for CO2 storage -1990 estimate [13]

	Global Capacity	
Storage Option	Gt CO2	% 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 also has been used for enhanced oil recovery, by injecting CO2 into oil fields, either by miscible (where CO2 is injected alternating with water) or immiscible (to increase or maintain reservoir pressure) technologies. CO2 is also considered for enhanced gas recovery in gas fields [2]. Injection pressure is a function of injection depth. As a benchmark, for 800m depth, the reservoir pressure is about

75 bar, and for deeper reservoirs, CO2 will be supercritical (Figure 6). Known CO2 injection applications operate in the dense phase area (Figure 7).

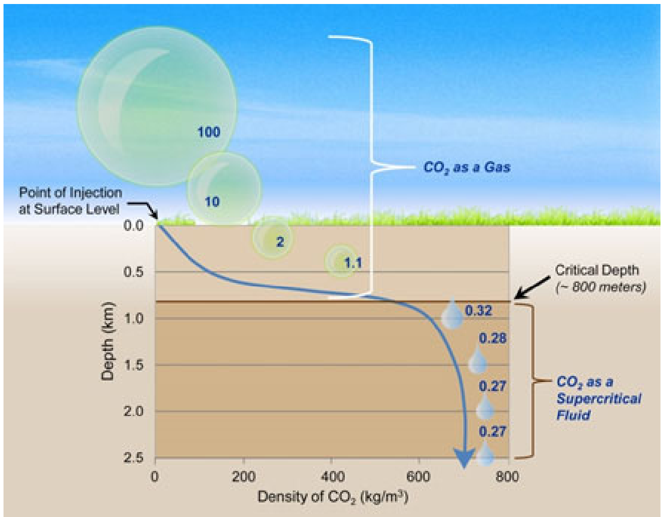

Fig. 6 CO2 density as a function of storage depth. CO2 reaches supercritical pressure and volume at about 800m depth.[14]]

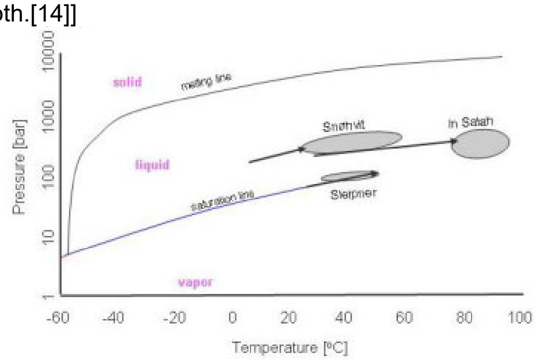

Fig.7 Phase Diagram of pure CO2 with well head and bottom hole conditions (arrows), reservoir conditions (shaded areas) for 3 sequestration sites (Sleipner, Snohvit and In-Salah).Note that while the CO2 cools down in the Sleipner reservoir, it heats up at In-Salah and Snohvit. Snohvit and Sleipner are off-shore, while In-Sah is an on-shore site. Reservoir depth below seafloor or surface, respectively, is 700m (Sleipner), 1700m (In Salah) and 2400m (Snohvit)[10].

A typical sequestration application for onshore systems may take CO2 from a hub, at 25 to 50 bar and bring it to a discharge pressure of 170 to 200 bar. This can be effectively accomplished with a single body intercooled inline compressor. The flow and injection pressure in such an application will be subject to fluctuations.

III. HYDROGEN

Hydrogen as a means of energy transport and storage is part of the discussion to reduce the societal carbon footprint. Figure 8 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 for example via Steam Methane reforming, Cyan hydrogen for example via Pyrolysis).

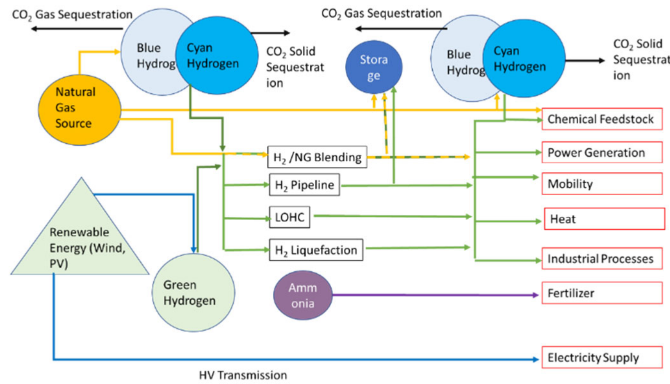

Fig. 8 Transportation pathways for hydrogen [4]

In all cases where hydrogen is generated from fossil fuels, the resulting CO2 would have to be captured and sequestered (see above).

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 NOx)
- 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 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 must be captured and sequestered.
As we will see, transporting energy as natural gas is more efficient than transporting hydrogen as a gas, or electricity. Liquid Organic Hydrogen Carriers (LOHC), which are organic compounds that can absorb and release hydrogen through chemical reactions, 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 the transport of hydrogen, it may be advantageous to locate Steam Methane Reformers close to the point of the hydrogen use 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. It should be noted that

hydrogen is already a valuable feed stock in the refinery and chemical industry.

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 photovoltaic (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. Hydrogen and derived chemicals allow both the storage of large amounts of energy and allow this storage for long durations [15].

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. For the most part, turbomachinery that either utilizes or transports hydrogen is not affected from where and how the hydrogen was created, but it is still important to understand the basic nomenclature [16].

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, the gas is called *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. Yes, there is 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.

The production source can make a difference both in the pressure at which the hydrogen is available and the composition of the hydrogen gas. This is important, because as we will see compression of hydrogen is very energy intensive. For the same energy flow, the compression work for a given pressure ratio for hydrogen is four times higher than for natural gas. 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. If hydrogen is used as a fuel, impurities impact combustion characteristics and exhaust gas composition. 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. The source of hydrogen may also cause byproducts: 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 10 kilograms of carbon dioxide are produced for one kilogram of hydrogen. The issues of carbon capture, transport and sequestration were discussed earlier [1].

Laughlin in [17] found that blue hydrogen, adding the cost for today 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 not be competitive if there are sufficient supplies of fossil fuels, and sufficient and convenient sequestration sites. This is because 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.

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.
2. Compression from a Steam Methane Reforming Process (blue hydrogen): The compression requirements are similar as for green hydrogen.
3. If the pipeline has to cover reasonable 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. [3,15,18] 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 9).
4. 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. Long term storage of hydrogen natural gas mixtures can lead to stratification of hydrogen in the storage facility, which can then lead to significant fluctuations and peaks in Hydrogen concentration. 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.

5. 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 (700 to 900 bar).

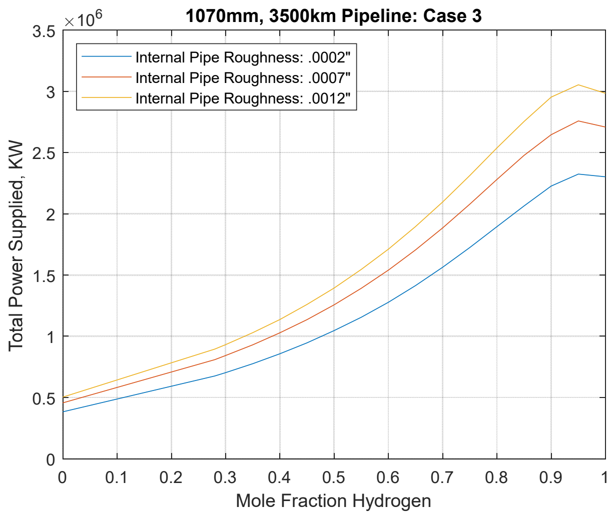

Fig.9 Hydrogen blending increases compression work. Note that the increase in power demand is only valid for this example. Other examples will lead to different results but will show generally the same trend [3].

A. 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 CO_2. 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 (ie the head is directly related, via Euler's 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 head translates into only little pressure ratio (Figure 10). 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 [4].

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, we need to find ways to increase the amount of work we can do per compressor stage, or per compressor body. This can be accomplished by combinations of higher tip velocities, less backsweep, 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 [4]. In this paper, we will not address the compression requirements for liquefying hydrogen. The question about the type of driver, either electric motor or a combustion engine will be covered later.

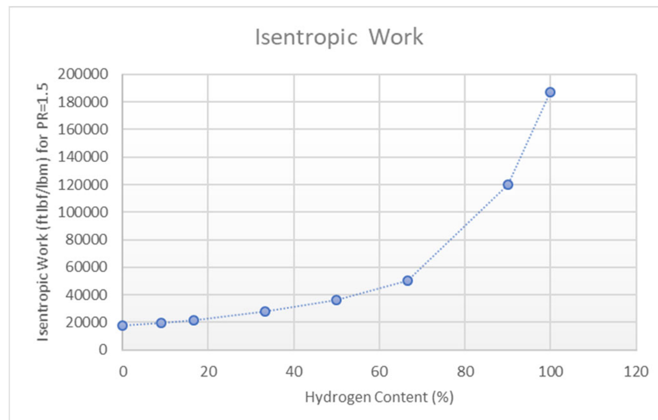

Fig. 10 Isentropic work required for a pressure ratio of 1.5, depending on the amount of hydrogen added to typical pipeline quality natural gas [16].

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. [15] have analyzed pipeline behavior if 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 [15]. Therefore, the transport capacity of the pipeline in terms of energy flow will be reduced (Figure 11). 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 11, 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.

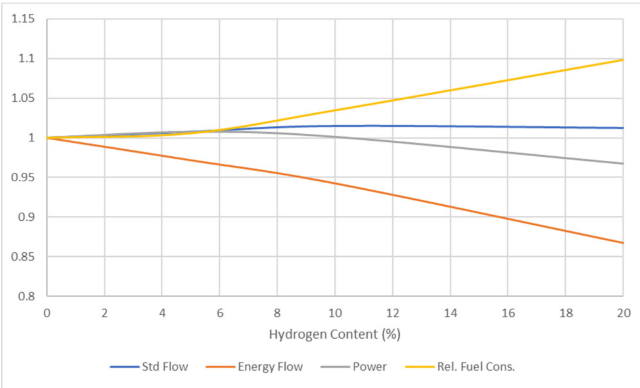

Fig.11 Result of adding hydrogen into a natural Gas Pipeline [15]

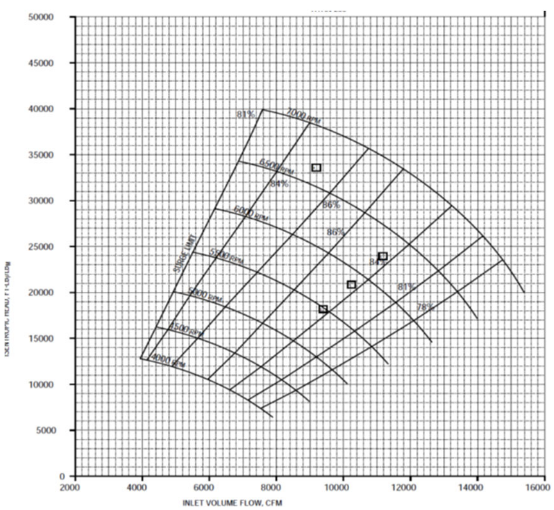

Fig. 12 Compressor Operating points for fluctuating hydrogen demand [15].

Figure 12 shows the operating conditions a centrifugal compressor would see, assuming a third compressor train is added to provide the necessary additional power. The station for this example would be sized to accept up to 20% hydrogen. The centrifugal pipeline compressor would be sized to have ample speed margin and ample turndown for the cases where no hydrogen is in the pipeline. The station would operate two of trains for hydrogen contents up to about 10%, and then start the third unit for concentrations up the 20%.

IV. STORAGE

Storage of gases in geological formations (Figures 6,7 and 13) is well established for natural gas storage, and under discussion for CO2 sequestration as well as hydrogen storage. 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 [19].

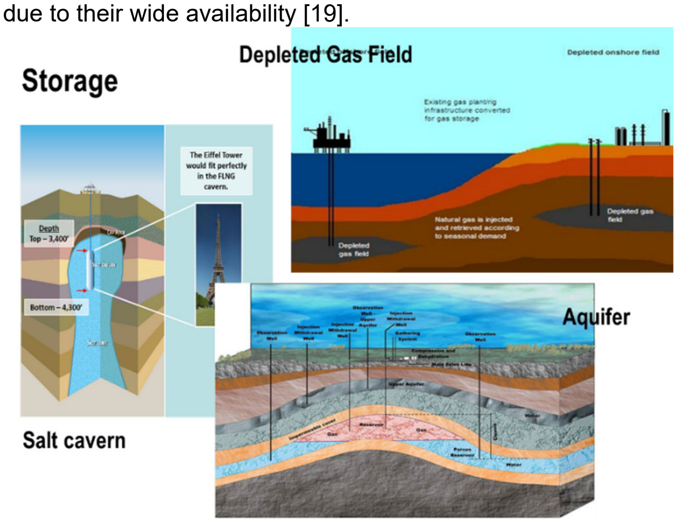

Fig.13 Underground Storage [8]

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 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 based on 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 [19]. 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.

Regardless, the storage pressures would be in the range of 100 to 200 bar, or higher, thus requiring significant amounts of compression. Other large scale storage concepts include contained membranes.

Compression to inject the CO_2 into the storage facility brings the CO2 from delivery pressure (100 to 150 bar) to injection pressure. Depending on the type of storage facility, this could be 200 bar (3000psi) 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. The flow demand is to some extent determined by facility limitations (for example, erosion limits).

V. DRIVERS

Unlike the transport and injection of, for example natural gas, the choice of drivers is limited by the fact that CO2 cannot be used as a fuel. Thus, unless a nearby source of natural gas is available, the drivers will likely be electric motors. Additionally, the fact that a driver using a carbon-based fuel would in turn also require the capture and compression of the resulting CO2 also would favor the use of electric motors.

Would these electric motor drives be constant speed or variable speed drives? Two factors are important: The first one is the requirement to start the motor, where a VFD drive offers advantages, the second and more important one whether the compressor can be efficiently adapted to the range of required operating conditions.

It must be assumed that the flow for the carbon capture compression will vary depending on the load profile for the drivers. While the suction and discharge pressures are set by the process, the flow will fluctuate. In most discussions, it is assumed that compressors for these applications are integral gear type machines, which usually are operated at constant speed (often due to rotordynamic limitations of a multi shaft system) and use adjustable vanes for control. The drivers will likely be constant speed motors, that will require starting systems [20]. The compressors or pumps in the pipeline systems will usually require the capability to operate at variable speed. Gas injection operations, such as for sequestration, will probably use preferably variable speed machines for inline compressors.

If variable speed electric drives are desired, either a VFD driven motor (Figure 14) or Variable Speed Hydraulic Drive (VSHD, Figure 15) can be used. A VSHD shows a speed - power relationship similar to a two-shaft gas turbine, but with a smaller usable speed range.

Hydrogen, on the other hand, can be used as fuel for gas turbines, or gas engines [15]. Thus, these compressors can

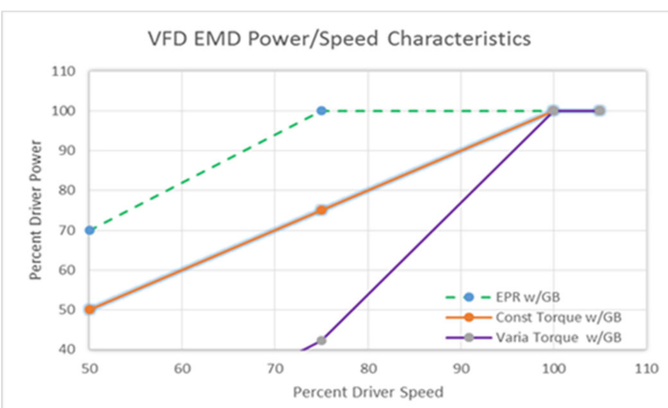

Fig.14 Speed-power characteristics for variable frequency drives [20].

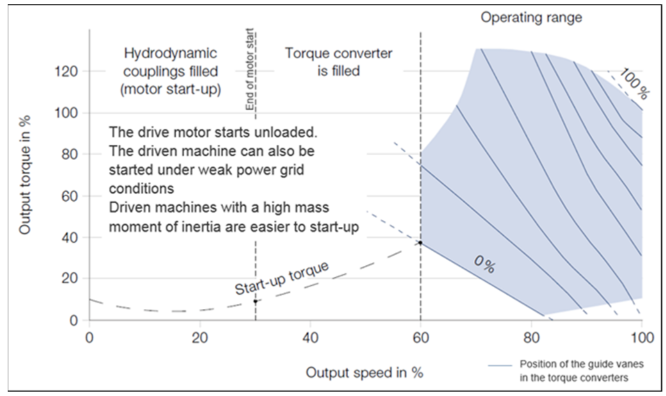

Fig. 15 Operating map of a VSHD [20]

be driven by gas turbines, gas engines, or electric motors. The answer will depend on the application:

1. Compression from the electrolyzer to pipeline pressure (Green hydrogen). Since the electrolyzer is used to convert available electricity, it stands to reason that the compression duty would use an electric motor.
2. Compression from a Steam Methane Reforming Process (blue hydrogen): In this application, hydrogen and natural gas are available. If the site is close to a power plant, because the blue hydrogen is used as a fuel for power generation, electricity is also available. The natural gas can be used to drive a gas turbine, but to achieve carbon neutrality, the CO2 would have to be captured and sequestered. More likely. Either the produced hydrogen would be used as fuel for a gas turbine, or some of the generated electricity would be used for an electric motor. In either case, the start of the entire system may require some extraneous power or fuel source for start-up.
3. Boost compression in a pipeline. The hydrogen, or hydrogen natural gas mixture transported in the pipeline can be used as fuel for a gas turbine, Only if pure hydrogen is transported, the combustion products are carbon free. For natural gas-hydrogen mixtures, carbon capture and sequestration methods would have to be used. Given the relatively small amounts (in comparison to the amount of gas transported) of CO2 generated, this CO2 could be mixed into the pipeline gas. If green electricity is available, electric motor drives would not create any additional CO2.
4. Storage compression. The same arguments stated for boost compression in a pipeline also apply to storage compression.
5. Fuel gas compression, and similar. The arguments are similar to storage and pipeline compression for pure hydrogen. Hydrogen Natural gas mixtures would favor electric motors if CO2 emission are to be avoided.

Electric motor configurations include constant speed motors driving the compressor via a variable speed gearbox and variable frequency drive (VFD) speed-controlled motors driving the compressor either directly or via a gearbox [21]. The performance characteristics of the driver, for example the power as function of ambient conditions, or the power output at various output speeds have been discussed in [21]. In many instances, a VFD controlled motor is a constant torque machine, thus exhibiting a linear drop in power with speed (Figure 14).

Another feature of importance is the fact that the electric motor output is not subject to changes in ambient temperature (within limits). This means that it lacks the convenience of providing more power at lower ambient temperatures, but it has the advantage that the same power is available on hot and cold days. This can be important in applications where the load demand is dependent on ambient conditions.

Further, the starting characteristics, including the amount of torque at low speeds, or, for constant speed electric motors, the amount of additional current is required during starting must be considered (Figure 16).

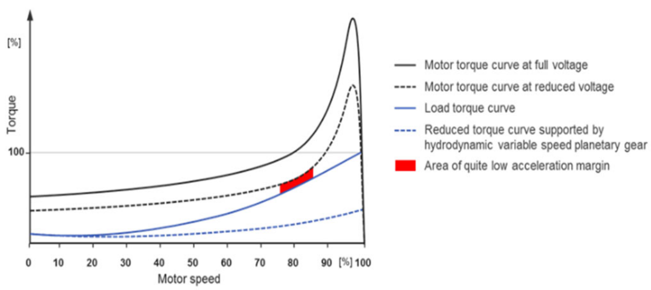

Fig.16 Squirrel cage induction motor capability curve at different voltage levels and load torque curve [20]

VI. POWER GENERATION: BLUE HYDROGEN OR CARBON CAPTURE?

In the context of carbon reduction for natural gas fired power plants, there are two fundamentally different approaches: Capturing carbon from the exhaust of the gas turbine or providing a fuel that does not contain carbon [1]. To generate a certain amount electricity in a gas turbine plant carbon-free, the choices are:

1. Feed natural gas to make blue hydrogen, compress the hydrogen to combustor pressure, capture the CO2 created in the process, and compress is to a pipeline or sequestration pressure
2. Burn natural gas in a gas turbine, capture the CO2 in the exhaust and compress the CO2 to pipeline or sequestration pressure.

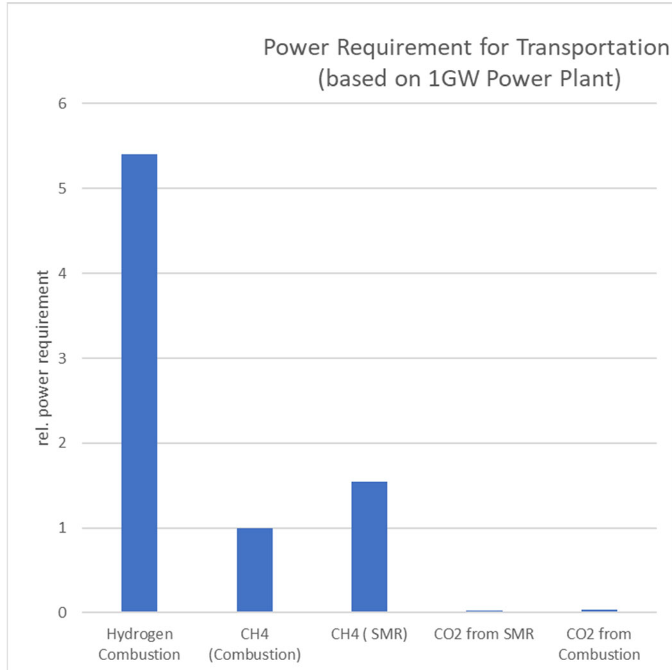

Figure 17: Power requirement for Transportation

This raises the question: If the CO2 stream, the methane stream and the hydrogen stream must be transported, what is the relative energy consumption? In Figure 17, the power requirements for identical transportation distances are compared for the transport of hydrogen, Methane, and CO2. The assumptions are made for the gas streams to and from a 1GW power plant with 50% thermal efficiency. The power for transportation is based on data in Allison et al [3] for methane and hydrogen transport, and for a pipeline simulation using a commercial code for the CO2 stream. In each case, the pipelines were optimized. For the methane and hydrogen pipelines an operating pressure of 103 bar was assumed, while 140 bar operating pressure was used for the CO2 pipeline to stay in the supercritical region. The key finding is, that hydrogen transport requires the most energy to transport (Figure 17). CO2 transport in supercritical state requires only a small fraction of the energy needed for hydrogen or methane. This means that bringing methane 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.

VII. CONCLUSION

The study identifies and explains the various compressor applications that occur in the context of carbon reduction efforts. Two key areas are the capture, transport and sequestration of CO2, and the transport and storage of hydrogen. The difficulties of hydrogen compression, and the challenges from CO2 compression have been outlined. Driver options have been discussed. In the context of power generation, the higher CO2 flow for blue hydrogen compared to CO2 from combustion processes seems to put an advantage to post-combustion capture methods.

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IX. VITAE

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Mrs. Mcbain previously worked at Southwest Research Institute for ten years in the pulsation analysis and turbomachinery groups as well as Apache Corporation for four years as a senior facility engineer. She holds four patents mainly related to innovative pulsation control concepts and has published over thirty publications related to natural gas machinery. Her career is supported by a BSME from the University of Texas at Austin and an MSME from Georgia Tech.

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