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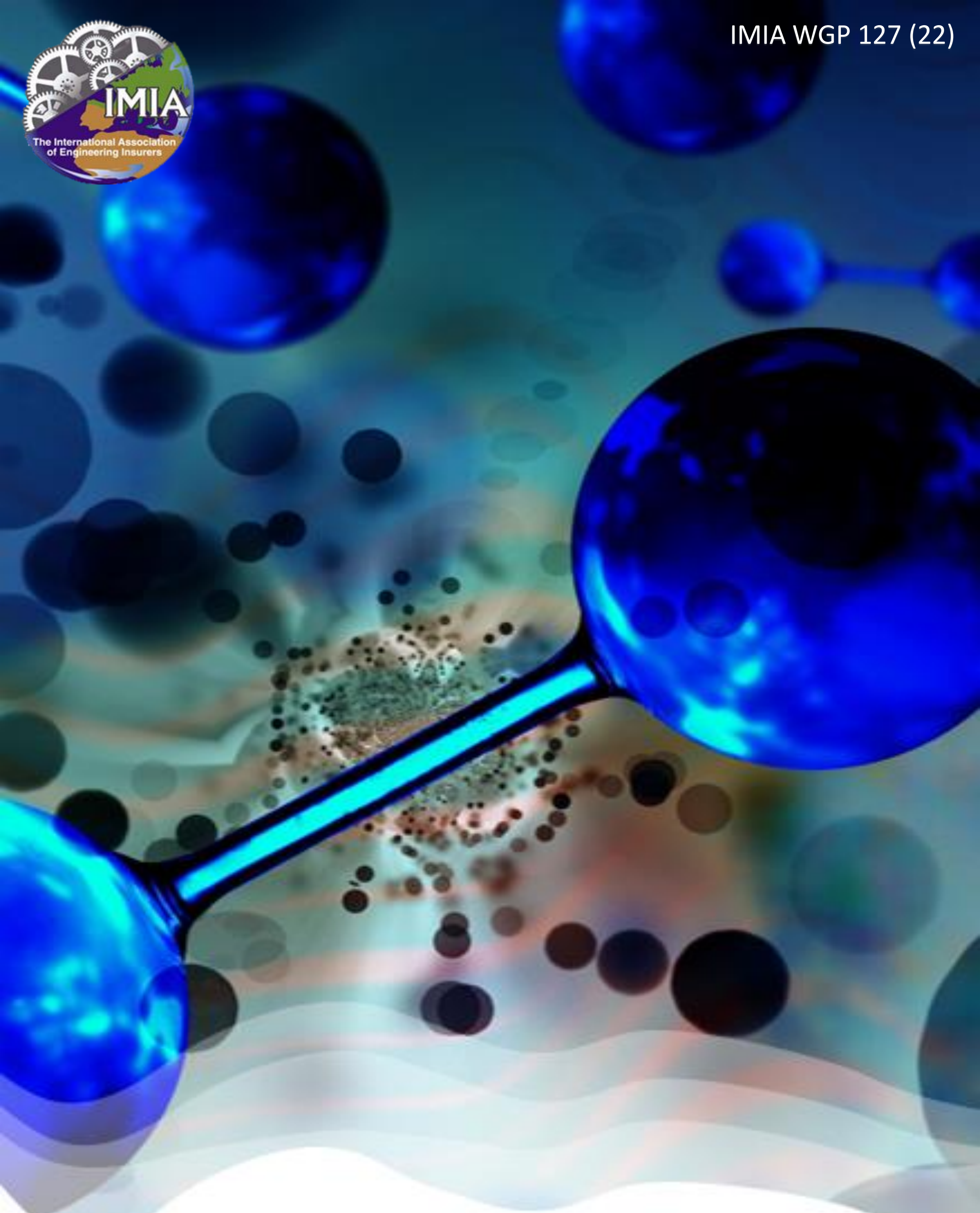

Insuring Hydrogen Infrastructure

Construction and Operation

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How to read this document

The intention of this document is to provide Underwriters, Risk Engineers and interested members of the insurance community with relevant insights about hydrogen technology, associated risk drivers, mitigation measures, considerations while analyzing risk and structuring cover as well as assessing claims and relevant wordings.

In the race for decarbonizing energy production and heavy industries, hydrogen will play a key role as energy carrier and feedstock. New developments, projects, ideas are announced daily.

In knowledge that many statements may become obsolete in a near future our team focused on risk and implications for the insurance industry.

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1. Why Hydrogen?

Decarbonization is the key to stop the manmade climate crisis and secure a sustainable future. At this crucial moment in time, key factors such as political consensus, technological innovation, investment momentum and – most recently - geopolitical pressure towards energy independence are converging and will boost the energetic transformation of the economy within the next decade. Within this global transformation, hydrogen is well placed to become an affordable, reliable, and clean (low-to-zero carbon) fuel source. Being part of most governmental roadmaps to net-zero and recognized as a game changer for the energy transition by the International Energy Agency (IEA) and the United Nations Intergovernmental Panel on Climate Change (IPCC), hydrogen has already gained momentum in global energy markets. As the hydrogen economy begins to scale and with significant investments ahead, we must not forget about the significant risks this relatively young industry faces. We therefore believe that it is time to talk about the importance of risk management.

Our mission:

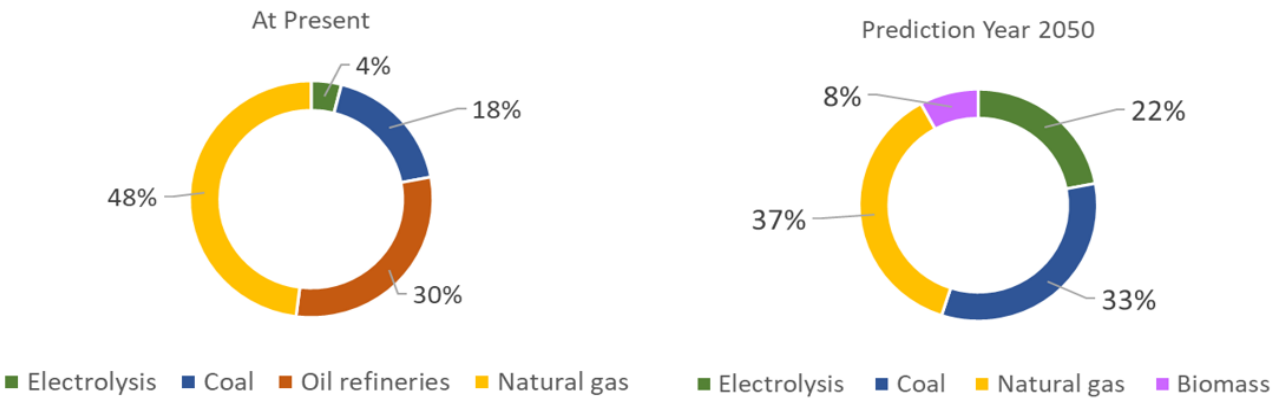
- Help understand and manage hydrogen risk from a holistic and interdisciplinary point of view
- Engage with a global community of experts across all segments of the hydrogen economy
- Assist businesses to assess the bankability and insurability of hydrogen projects

1.1 Hydrogen is the game changer for the energy transition

As a fuel, hydrogen has the highest energy content by weight of all known fuels –3 times higher than gasoline[1]– and is a critical feedstock for the entire chemical industry, including for liquid fuels. Hydrogen (H_2) is also a clean-burning molecule. The only emission / by-product is water (H_2O). Hence, it could become a zero-carbon substitute for fossil fuels in hard-to-abate sectors of the economy and used to store, move, and deliver low- or zero-carbon energy to where it is needed.

Another advantage of hydrogen as a low carbon energy source/store is that it is a chemical fuel, meaning there is limited loss of energy over time, unlike current battery technologies. This could also help enable grid stability by being used as a responsive load or store, increasing the utilization of power generators, including nuclear, coal, natural gas, and renewables[2]. As a matter of fact, the IEA recognizes that hydrogen "is one of the leading options for storing energy from renewables and looks promising to be a lowest-cost option for storing electricity over days, weeks or even months"[3]. Apart from its key function as long term storage solution for renewable energy, hydrogen could also help decarbonize hard-to-abate sectors such as long-haul transport, chemicals as well as the steel industry.

1.2 Global hydrogen production shifts from grey to green as costs drop

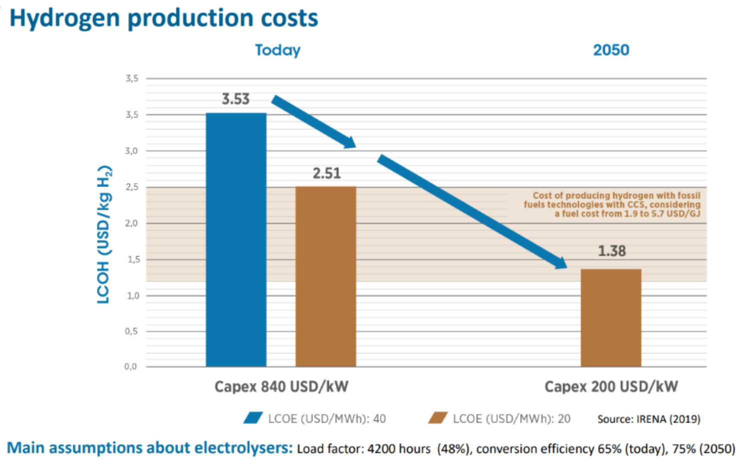


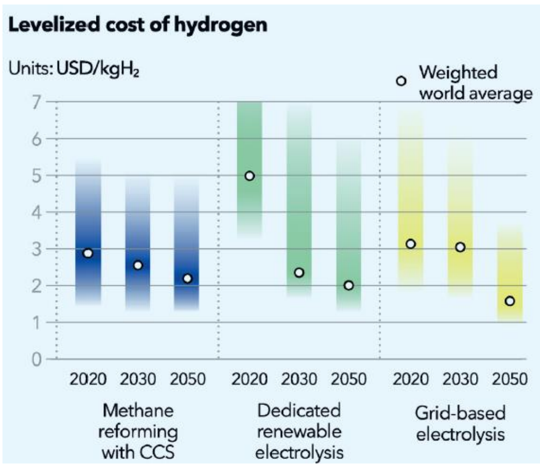
Breakdown of hydrogen production by energy source. Data from IRENA, International Energy Agency

At the time of writing this report most of the global hydrogen production comes from natural gas (grey hydrogen). The majority of scientific studies and industry reports agrees that this is going to change, and that green hydrogen produced from renewables is going to play a bigger role in the future. Currently green hydrogen struggles to compete with grey hydrogen; however, it is foreseeable that green hydrogen will become much more attractive going forward.

The cost of low-carbon and/or renewable hydrogen production will fall drastically by up to 60 per cent over the coming decade. This can be attributed to the falling costs of renewable electricity generation, optimization and scaling up of electrolysers manufacturing, and the development of lower-cost carbon storage facilities[4]

Green H_2 will expectedly develop as LCOEs of renewables continue to drop and economies of scale in electrolyser technology are leveraged. The cost of H_2 production is a function of electricity price and CAPEX for electrolysers. Dropping LCOEs for renewable energy, technology evolution and economy of scale will expectedly make Electrolysis cheaper over time. Also, the price for grey hydrogen (via steam reforming) will expectedly increase as the costs of both natural gas and CO_2 emissions will continue to rise. Hence, green hydrogen has a real chance to beat grey hydrogen in the near future. The point by which this is going to happen is mainly driven by policy making. Depending on the location of production, hydrogen from solar-PV has the lowest levelized cost of hydrogen in Europe. The levelized cost of hydrogen from the offshore wind value chain is second lowest[5].



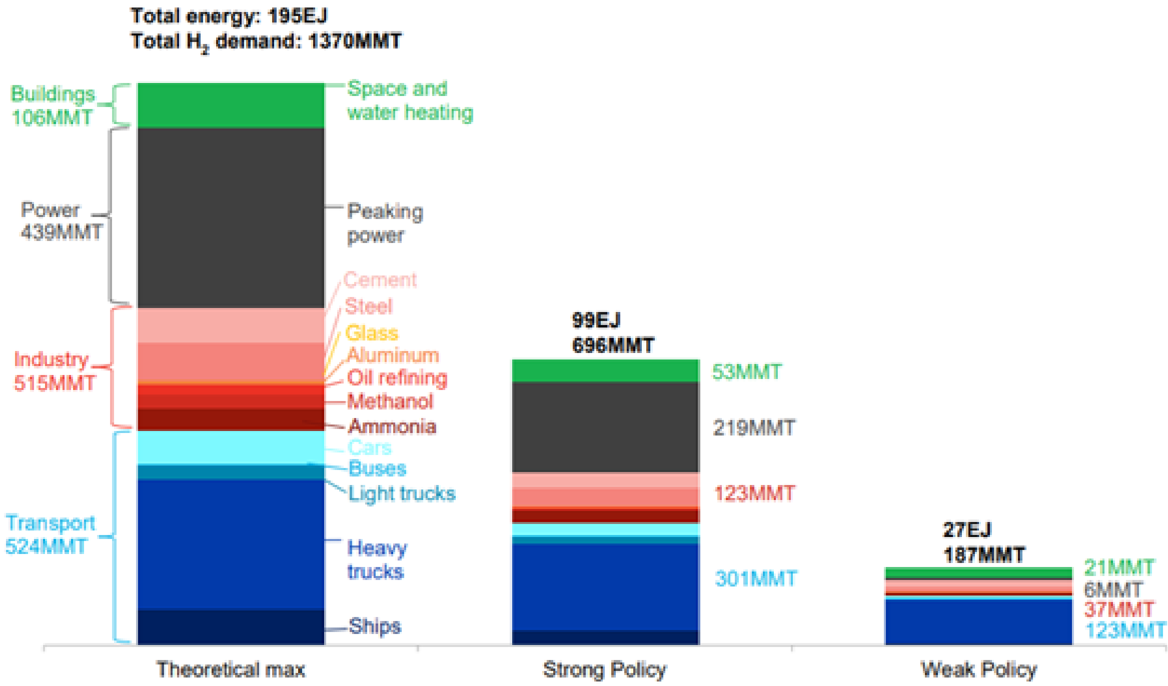


Expected development of hydrogen production costs. Source: IRENA.org / DNV Hydrogen Forecast

1.3 Political momentum for hydrogen and investment climate is favourable

Projections depending on policymaking, estimate that 187 million metric tons (MMT) of hydrogen could be in use by 2050, enough to meet 7% of projected final energy needs in a scenario where global warming is limited to 1.5 degrees. If a strong and comprehensive policy is in force, 696MMT of hydrogen could be used, enough to meet 24% of final energy in a 1.5-degree scenario. This would require over $11 trillion of investment in production, storage, and transport infrastructure. Annual sales of hydrogen would be $700 billion, with billions more also spent on end-use equipment. If all the unlikely-to-electrify sectors in the economy used hydrogen, demand could be as high as 1,370MMT by 2050[1].

In the IEA's Net Zero analysis, hydrogen use extends to several parts of the energy sector and grows sixfold from today's levels to meet 10% of total final energy consumption by 2050. This shall be supplied from low-carbon sources



Hydrogen demand expectations depending on policy making. Source: Bloomberg "Hydrogen Economy Outlook"

Against this background it becomes apparent that the development of the hydrogen economy is going to depend primarily on policy decisions. When looking at current hydrogen policies, there is no doubt that there is unprecedented positive momentum for hydrogen across the world.

Europe leads globally in the number of announced hydrogen projects, with Australia, Japan, Korea, China, and the USA following as additional hubs. Of all announced projects, 55% are in Europe. While Europe is home to 105 production projects, the announced projects cover the entire hydrogen value chain including midstream and downstream. The European Commission declared in July 2021 its ambition to increase the production capacity of electrolysers from 250 MW today to 40 GW in 2030. Pursuant to legislation, Germany will switch off all coal plants (36 GW in 2020) by 2038[6] as well as its existing nuclear plants by 2022[7].

The US Energy Department announced in June 2022 that it will spend $8 billion on at least four hydrogen "hubs" that will build out a network for producing, processing, delivering, and storing hydrogen with the main aim of decarbonizing the industrial sector.

Many countries in the APAC region have ambitious plans to develop a hydrogen-based economy.

In 2017, Japan issued the Basic Hydrogen Strategy, becoming the first country to adopt a national hydrogen framework. Japan is focused on expanding its hydrogen market from two million tons per year today to three million tons per year by 2030 and 20 million tons per year by 2050; through scale while driving down the cost of hydrogen to about one-third of the current level by 2030[8]. Attention on hydrogen in China has surged after announcements by companies promising investment in emerging technology. The China Hydrogen Alliance was jointly launched in 2018 by large companies in areas such as energy production, equipment manufacturing, transportation, metallurgical materials, universities, and research institutes. Hydrogen could account for 20% of China's energy mix by 2060, the deadline that the Chinese Government has set for China to become a carbon-neutral country.

Although current geopolitical tensions may put these policies to the test in the short term, the hydrogen economy will continue to scale.

1.4 Hydrogen: an industry in its infancy must overcome many challenges

At the time of issuing this report (Q3, 2022), the hydrogen industry is still in its infancy and has only recently begun to develop at a larger scale globally. Even though electrolysis and H_2 processing are known technologies, their application at a larger scale and in the context of green H_2 is genuinely new.

Not only prototypes and unproven technologies are critical; scaling up of components, balance of plant, design, and operational procedures as well as standards addressing the human factor represent key risk elements to consider.

As a result, there is a lack of trusted industry standards and certification procedures. Despite the favorable investment climate, large classification societies such as DNV have initiated joint industry projects to establish such important safety standards and ultimately increase confidence in the electrolyser market. Accordingly, certification standards have been developed by the European Union (EU) as well as by private service providers such as TÜV. ISO standards are in development at the time of publication of this paper.

Collaboration on technologies and development as well as harmonization of regulations, codes and industry standards is seen as key to reduce uncertainties and risks in developing large H_2 projects at scale. It is worth noting that such standards ultimately should aim at entire H_2-projects and all equipment used along the often complex and highly integrated H_2 value chain, rather than just the electrolyser equipment itself.

Drawing a conclusion one can argue that the hydrogen industry faces a dilemma. It is primed to attract unprecedented investment, scale up fast across the globe and evolve technologically. On the other hand, there continues to be significant challenges associated to technology maturity, standards and regulation as well as hydrogen demand, supply chains and business models. Against this background the hydrogen industry continues to bear a significant level of risk for investors, developers, suppliers and operators alike. Continued investment in research, the development of standards and best practice exchange on risk management is crucial to secure bankability and insurability of hydrogen projects and thus allow the hydrogen economy to prosper.

Key takeaways:

- Hydrogen is a clean burning molecule with high energy content, which as chemical fuel has the potential to decarbonize even hard to abate sectors of the economy and serve as an important means of long-term energy storage
- Development will depend strongly on policy making. There is an unprecedent political momentum fueled by geopolitics and a growing pipeline of projects
- Cost of green hydrogen is primed to fall, technological developments focus both on reduction of capex (equipment size and complexity, scale up of production, use of rare metals) and operational cost (energy consumption). Accordingly other forms of hydrogen will become less competitive over time
- Regulation, codes, and standards are under development, but are likely to lag behind technology and market development in the foreseeable future
- Complex business models and values chains will continue to develop
- To secure bankability and insurability of hydrogen projects it is crucial to acknowledge the challenges of the hydrogen industry and continue to invest in risk management

2. Hydrogen Production

Methods of production can be divided into thermochemical, electrochemical, photochemical, or biological processes to Hydrogen[9], an extract of methods / technologies is shown below.

Process Category	Energy source	Chemical feedstock	Conversion Technology	Efficiency (%)	Cleanliness (C/N/CCS)	Technology maturity level (1-10)
Thermochemical	Heat	Fossil Fuels	Steam reformation	60-85	N/CCS	10
		Fossil Fuels and biomass	Partial oxidation	55-75	N/CCS	7-9
		methane	Autothermal	60-75	N/CCS	6-8
		coal	Coal gasification	74-85	N/CCS	10
		biomass	Biomass gasification	35-50	N	10
		methane	Methane pyrolysis	40-45		
Electrochemical	Electricity	water	Alkaline electrolysis	62-82	C	9-10
		water	Proton exchange membrane electrolysis	67-84	C	7-9
		water	Solid oxide electrolysis	75-90	C	3-5
		water	Anion exchange membrane	-	C	-
		water	Membrane-less electrolysis	-	C	-
Photoelectrochemical	Light	water	PEC Electrodes	0.5-28	C	1-2
		water	Photocatalytic slurry	-	-	1-2
Biological	Bioenergy	Microorganism	Dark-Fermentation	60-80	N	3-5
		biomass	Microbial Electrolysis	70-80	N	1-3

Comparison of hydrogen production methods[10]

Hydrogen has been produced from various renewable and non-renewable energy resources such as fossil fuels, especially steam reforming of methane, oil/naphtha reforming, coal gasification, biomass, biological sources, and water electrolysis. Combinations of feedstock, energy source, production method and the handling of by-products have led to a color-coding system for H_2 production processes.

2.1 Thermochemical methods

Steam Methane Reforming

Steam methane reforming is a well-established technology that currently dominates the supply market, mainly because the capital cost is relatively low, and the chemical reaction is easy to control with reformer plant capacities ranging between 50-1000 MW[11].

Carbon capture storage (CCS) systems in the effluent gas aims to drastically reduce CO_2 emissions and decarbonize the sector. Steam reforming can also be used to produce hydrogen from other fuels, such as ethanol, propane, or even gasoline[12].

Future development: As SMR is the most technologically mature method of H_2 production, future developments are likely to be aligned with abatement potential of greenhouse gases, through (retro)fitting carbon capture storage (CCS) technologies to production streams, shifting the H_2 from 'grey' to 'blue'. SMR with CCS is estimated to reduce the lifecycle GWP footprint to levels around ~5 kg CO_2-*eq* / kg H_2[11].

However, addition of CCS to obtain high purity H_2 and reduce CO_2 is estimated to reduce SMRs energy efficiency to ~60% and could increase the cost of production[13].

No major development in steam methane reforming for greenfield projects is expected in the future

Partial oxidation (POX)

Compared to steam-methane reforming, this method reduces the level of external heat input in the production process, and the POX reactor is typically more compact than a steam reformer as the heat exchanger is no longer needed.

Partial oxidation can be performed without a catalyst and thus has better tolerances for sulfur impurities from the fossil fuel source. As POX is a mature technology, future developments of POX H_2 production are expected to be aligned with the generation of blue hydrogen through additional CCS technologies in the production stream.

POX plants are used to form hydrogen, carbon monoxide, carbon dioxide and water from the residues (liquids, highly viscous hydrocarbons) of the refining process[14].

Autothermal reforming (ATR)

The autothermal reforming method combines steam-methane reforming with the partial oxidation method. It allows the production for hydrogen via connecting the devices of two processes in series. The heat required for ATR comes from the partial oxidation of natural gas and the exotherm energy of the oxidation process is used to achieve steam reforming[15].

ATR is more efficient because heat from the exothermic oxidation step can be utilized by the reformation reaction, but ATR also requires an oxygen input[11]. Future development mainly focuses on the combination of ATR and carbon capture and sequestration (CCS) for blue hydrogen generation.

2.2 Electrochemical methods

The dominating electrochemical hydrogen production method is electrolysis, using electric current for the splitting of water into hydrogen and oxygen.

Electrolysis is a surprisingly old technology, with the first units in operation already more than 100 years ago. It was the main way to produce hydrogen until the 1960s, when steam reforming supplanted it.

Four basic electrolysis technologies are commercially available today for hydrogen production, with decreasing maturity:

- Alkaline
- Proton Exchange Membrane (PEM)
- Anion Exchange Membrane (AEM)
- Solid oxide

Further electrolyser technologies are under development, e.g., the membrane less electrolyser, microbial electrolysis or electrolyser operating with salt water.

One of the major risks for electrolysers in general, besides leakages is the diffusion of product gases.

	Alkaline	PEM	AEM	Solid Oxide
Operating temperature	70-90 °C	50-80 °C	40-60 °C	700-850 °C
Operating pressure	1-30 bar	< 70 bar	< 35 bar	1 bar
Electrolyte	Potassium hydroxide (KOH) 5-7 $molL^{-1}$	PFSA membranes	DVB polymer support with KOH or NaHCO3 1$molL^{-1}$	Yttria-stabilized Zirconia (YSZ)
Separator	ZrO_2 stabilized with PPS mesh	Solid electrolyte (above)	Solid electrolyte (above)	Solid electrolyte (above)
Electrode / catalyst (oxygen side)	Nickel coated perforated stainless steel	Iridium oxide	High surface area Nickel or NiFeCo alloys	Perovskite-type (*e.g.* LSCF, LSM)
Electrode / catalyst (hydrogen side)	Nickel coated perforated stainless steel	Platinum nanoparticles on carbon black	High surface area nickel	Ni/YSZ
Porous transport layer anode	Nickel mesh (not always present)	Platinum coated sintered porous titanium	Nickel foam	Coarse Nickel-mesh or foam
Porous transport layer cathode	Nickel mesh	Sintered porous titanium or carbon cloth	Nickel foam or carbon Cloth	None
Bipolar plate anode	Nickel-coated stainless steel	Platinum-coated titanium	Nickel-coated stainless steel	None
Bipolar plate cathode	Nickel-coated stainless steel	Gold-coated titanium	Nickel-coated Stainless steel	Cobalt-coated stainless steel
Frames and sealing	PSU, PTFE, EPDM	PTFE, PSU, ETFE	PTFE, Silicon	Ceramic glass

Note: Coloured cells represent conditions or components with significant variation among different companies.
PFSA = Perfluoroacidsulfonic; PTFE = Polytetrafluoroethylene; ETFE = Ethylene Tetrafluorethylene; PSF = poly (bisphenol-A sulfone); PSU = Polysulfone; YSZ = yttriastabilized zirconia; DVB = divinylbenzene; PPS = Polyphenylene sulphide; LSCF = $La_{0.58}Sr_{0.4}Co_{0.2}Fe_{0.8}O_3$-δ; LSM = $(La_{1-x}Sr_x)_{1-y}MnO_3$; § = Crofer22APU with co-containing protective coating.

Based on IRENA analysis.

Source: IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal

Alkaline electrolysis

This technology is well established up to the megawatt range for commercial applications. Investment costs are very high when compared to conventional hydrogen production. Currently, novel membranes and AEM processes are being developed in order to reduce the costs. For example, Evonik introduced in September 2020 a new AEM process using a resistant polymer membrane with very high conductivity[16].

Module sizes from 1 MW to 4 MW are considered today proven technology, larger modules will be developed in the future. Thyssen Krupp and Uhde Chlorine propose a 20 MW module. The module can be put in containers 40" to 46" with a weight of 36 t to 40t. Several modules will be stacked and operated in parallel.

"In the alkaline electrolysis a conductive fluid is utilized, normally a caustic potash/water solution. The OH- are then transported through the diaphragm. This diaphragm is fully permeable for the solution. When there is a load change required e.g. due to renewable electricity as energy source, oxygen and hydrogen start fluctuating on both sides since the diaphragm is rather like a mesh, this increases the risk of process runoff. The explosion protection limit is 4% hydrogen in oxygen, this means that alkaline electrolysers should be operated with a safety margin below this limit.

There are some national norms stating 2% as operational limit e.g. in Austria. In conclusion, for transient operation, alkaline systems are far more susceptible to runoff than PEM systems. Alkaline systems can handle load changes in the range of percentage per minute"[17].

Another aspect is idle operation. When the system is shutdown, the electrodes are in a very aggressive environment, which requires protection of the electrodes. This occurs by applying a current to the electrodes. This translates into a higher electricity consumption at idle than in PEM systems.

Alkaline electrolyser technology has been in operation in industry for many decades.

The main risks are in the stability of the diaphragm (durability, subject to operational parameters, operating out of design parameters) and are rather general risks for plant design and scaling up, not related to the technology. Up-scaling issues are related to control systems, larger components, compressors, new materials, and changes in manufacturing process.

Proton exchange membrane electrolysis (PEM)

PEM electrolysis has been commercially available since the beginning of the 21st century. PEM water electrolysis technology is similar to the PEM fuel cell technology, where solid polysulfonated membranes (Nafion®, fumapem®) was used as electrolyte[18].

The main advantage of PEM compared to alkaline electrolysis is the very low permeability between the gases on both sides of the reaction, this means a much higher intrinsic operational safety. "PEM systems can handle load changes and transient operations in a much safer way than alkaline electrolysers (10%/sec load change)"[17].

One disadvantage of PEM systems is the fact that they are an electrochemical unit, which means it is subject to aging when at idle operation (similar to batteries). The aging process with PEM technologies is less predictable than with alkaline systems. Therefore, most industrial systems have adopted the EOH (equivalent operating hours) approach to manage electrolyser aging and the lifetime of components depending on operating regime. This to be understood as a risk mitigation measure. Many PEM systems operate with pressure, which reduces costs due to the reduced compression costs. The problem is that the diffusion of hydrogen in oxygen increments with higher pressure. These systems require special measures to reduce diffusion and/or to abreact hydrogen in the oxygen stream. Most of the electrolysers' OEMs procure the coated membranes, some others are coated with proprietary systems, and can recycle (up to 90%) the used membranes at the end of the determine EOH cycle. Coating is mostly based on platin (hydrogen side, used as a recombinator) and iridium (on the oxygen side).

Empirical tests are performed to reduce the required quantities of precious materials while maintaining an acceptable lifetime, this fact may represent a risk for operational safety and reliability of future systems.

The thickness of the membrane is the focus of further developments since this determines the ohmic resistance and thus the overall efficiency of the system. This optimization increases the risks of hot spots, which may cause a faster degradation of the membranes. With higher temperature and/or hot spots, fluor is faster degraded from the membrane. Fluor free membranes are thus a further focus of design optimization.

The quality of the surface of the Gas Diffusion Layer (GDL) is decisive regarding hot spot formation. With increasingly reduced membrane thickness, the risk of perforation increases. Well designed and thoughtfully tested compensation layers are recommended to reduce this risk

Cooling of the membrane (via increased mass flow of water) is a further factor for intrinsic operational safety, ideally both sides of the membrane should be cooled. Hot spot formation can be reduced by reducing the setpoint of systems temperature (most membranes start melting at 90°C)"[17].

Solid oxide electrolysis (SOE)

SOE cell electrodes and electrolyte are exposed to permanent high temperatures at high flows of electrical charges (currents) in an electrical field coupled with high gas flows and local moisture saturation. Ceramic materials and special steels appear to be the only substances capable of withstanding this demanding environment. Fuel electrode is typically made of porous Ni doped YSZ (yttria stabilized zirconia). The air electrode is a porous layer typically made of LSM (lanthanum strontium manganite). The most common electrolyte is a dense ionic conductor consisting of YSZ.

SOEs required temperatures around 500-600°C. This results in longer start-up times, mechanical compatibility issues such as thermal expansion mismatch, and chemical stability issues such as diffusion between layers of material in the cell.

Even ceramic materials are not inert under these conditions, SOEs have been observed to degrade primarily due to air electrode (anode) delamination from the electrolyte.

Compared with alkaline and PEM electrolysis, this system has the advantage that it can work on both directions (as Electrolyser and as Fuel Cell)

Anion exchange membrane electrolysis (AEM)

Using AEM water electrolysis, modular electrolysers can produce 500 NL of green hydrogen per hour, with a purity of 99.9 % (99.999 % after drying) at 35 bar pressure from 0.4 L of water and 2.4 kWh of renewable energy[19].

This technology combines the advantages of PEM and alkaline electrolysis and is at present in the development phase for commercial implementation

As one producer of AEMs puts it: "The goal is to reduce the use of precious metals while achieving the operational efficiency and flexibility of PEM. As by now this technology has been tested in small scale pilot plants, we expect this technology to become commercial in 5-10 years[17]".

Membraneless/-free and capillary-fed electrolysers

Although the economics of producing hydrogen from water electrolysis are currently dominated by the cost of electricity, electrolyser capital costs will become much more relevant with decreasing electricity cost for solar PV and wind.

These so-called membraneless electrolysers generally rely on flow- or buoyancy-induced separation of products whereby forced fluid flow (advection) and/or buoyancy forces are used to separate the O_2 and H_2 products before they can cross over to the opposing electrode. Membraneless electrolysers can be classified based on the type of electrodes employed

Two current challenges for membraneless electrolysers are product purity and safety. Lower product purity is a concern in regards of explosion and/or system runoff. Another safety concern is electrical arcing between electrodes, which could result in sparks if a large voltage is applied across a very small electrode gap. It is paramount that such operating conditions be avoided

For these reasons, process safety principles utilizing sensors, interlocks, and fail-safe design features should be used in designing membraneless electrolysers to ensure that (1) the electrolyser is not allowed to run outside safe operating conditions and (2) O_2 and H_2 products remain separated in the event of electrolyser malfunction (e.g., pump failure).

Capillary-fed electrolysers (CFE) are in early development, the aim is to drastically reduce electricity consumption, electrolyser operates reportedly at 95% system efficiency (less than 50 kWh/kg), delivering a leap in operating cost over incumbent technologies.

Electrolysers: Special considerations for integration with offshore wind

Motivation for producing hydrogen offshore is the cost for electrical transmission to shore. Electrical transmission per km cable is expensive compared to gas-pipelines.

Electrolyser per wind turbine concept: Each WTG location can be equipped with a container sized electrolyser. Transport of Hydrogen can then be performed via vessel or pipeline. This concept may be the best option for floating far offshore sites. Green hydrogen can be produced using an electrolyser array located at the base of the offshore wind turbine tower.

Electrolysers mounted on wind turbine platforms should reduce electric losses to a minimum, while a modular approach attempts for a reliable, efficient, and scalable operational set-up. On the other hand, the cost of repairs and maintenance will increase.

Electrolyser mounted on dedicated platform and/or integrated with offshore substation:

This approach foresees a centralized location for the electrolyser, hence on interface for handling of hydrogen and on location for maintenance. Currently, platform concepts are offering a basis for offshore hydrogen production in the range of 100 MW to 800 MW, this includes the electrolysis units and transformers for the transformation of the electricity supplied by the offshore wind turbines, along with desalination modules for producing the high-purity water required for electrolysis.

Centralization of electrolyser on a single platform leads to an overall cost reduction and competitive levelized cost of hydrogen but increases the hydrogen inventory and the size of critical equipment. DSU/BI exposure is increased due to the built-in bottlenecks

Electrolyser on an energy island: This approach integrates the electricity generation from several offshore windfarms on an island with harbor, service, and storage facilities. The idea is to share assets between different grids, so it is a more advanced way method of interconnection. This concept offers more flexibility in the distribution between hydrogen production and electricity transmission. Perhaps with a reduced electrical connection to the onshore grid.

Electrolyser next to grid connection point onshore: Electrolyser and storage for hydrogen combined with electricity production based on hydrogen installed onshore near a grid connection. This provides the best option to manage electricity demand with a volatile renewables supply. Additionally, the location has better environmental conditions and easier access compared to offshore. The downside is the expensive electrical connection to the offshore site.

Key takeaways:

- Currently ~96% of the global hydrogen production is from non-renewable fossil fuels, in particular steam reforming of methane.
- Post-combustion carbon capture can be retrofitted to conventional methods converting grey hydrogen production to blue
- Main risks of electrolysers are process run-off, lifetime of components and balance of plant related risks (materials, scale up of main components and storage)
- Onshore close to connection point is probably the preferred option for the integration with offshore wind from a risk perspective since offshore claims are dominated by logistic costs

3. Hydrogen applications

3.1 Hydrogen applications in heavy industries

For decades, hydrogen has been used as a raw material by the chemical industry, mostly in the production of ammonia (NH_3) and hence fertilizers, and in refineries, where hydrogen is used for the processing of intermediate oil products.

About 55% of the hydrogen produced around the world is used for ammonia synthesis, 25% in refineries and about 10% for methanol production. The other applications worldwide account for only about 10% of global hydrogen production[20].

Hydrogen also has a long history of use in several other industries. These include:

- Food: Hydrogen is used to turn unsaturated fats into saturated oils and fats, including hydrogenated vegetable oils like margarine and butter spreads.
- Metalworking: Multiple applications including metal alloying and iron flash making.
- Welding: Atomic hydrogen welding (AHW) is a type of arc welding in a hydrogen environment.
- Flat Glass Production: A mixture of hydrogen and nitrogen is used to prevent oxidation and therefore defects during manufacturing.
- Electronics Manufacturing: As an efficient reducing and etching agent, hydrogen is used to create semiconductors, LEDs, displays, photovoltaic segments, and other electronics.
- Medical: Hydrogen is used to create hydrogen peroxide (H2O2). Recently, hydrogen gas has also been studied as a therapeutic gas for several diseases[20].

The use of low-carbon hydrogen in refining faces an economic barrier due to its higher cost compared with unabated fossil-based hydrogen. However, replacing this hydrogen production capacity with low-carbon technologies would not be as technically challenging as adopting hydrogen for new applications. Therefore, this is an ideal opportunity to easily ramp up low-carbon hydrogen demand while decreasing the CO_2 emissions from refining processes.

Ammonia production

Ammonia is obtained on a large scale by the Haber-Bosch process. This process combines hydrogen and nitrogen together directly by synthesis. Nitrogen is obtained by low-temperature separation of atmospheric air, while hydrogen is typically produced on-site from hydrocarbons. Natural gas and coal are the two main hydrocarbon sources used today in ammonia production.

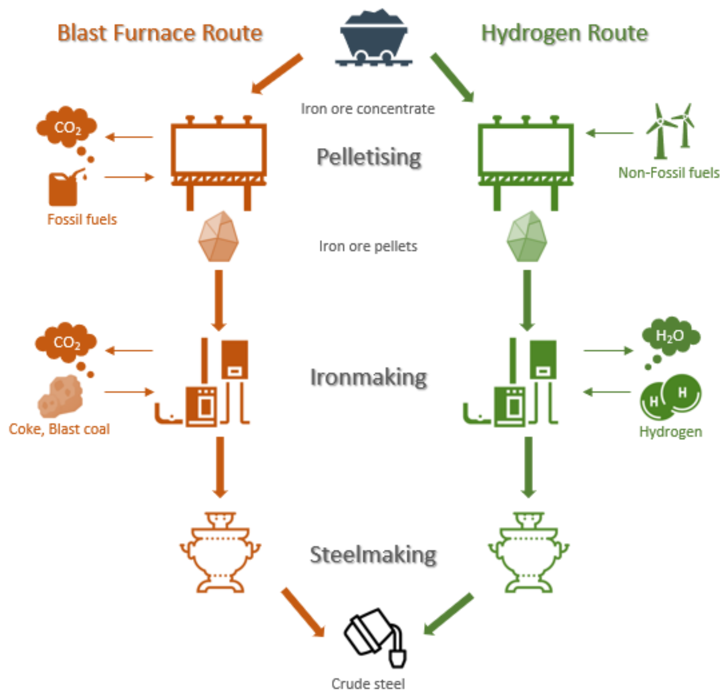
Ammonia is due to its energy density and storage capabilities a preferred potential (shipping) fuel and H_2 carrier, but its handling is critical. It is a caustic, water-seeking chemical which even at very low concentrations (>30 ppm) can cause serious health and environmental damage.

The using of electrolytic H_2 for ammonia production is at an early stage of development and thus the process integration (variable green power, products purity, increased storage, transient/cycling operations), spill/leaks (ammonia, nitrogen, hydrogen) can be seen as the main risk.

Steel production

Steel is one of the world's highest CO_2-emitting industries, accounting for about 8% of global annual emissions due to the use of coking coal in the blast furnace process. Each ton of steel produced today still results in 1.4 t CO_2 of direct emissions on average. Renewable energy can be also chosen as the energy source to produce hydrogen by water electrolysis to displace the use of an ancient industrial apparatus that is the blast furnace for metallic iron production from iron ore. Decarbonizing the average steel plant in the EU would require a minimum of 1.2-1.3 GW of renewable energy.[21]

See below picture, the left-hand side shows that iron ore concentrate is pelletized using fossil fuels, so that the mineral pellets and coke are fed into a blast furnace, which produces hot metal that is, subsequently, used to be transformed into crude steel. Coke and fossil fuels are used, and greenhouse effect gases and particulates and ashes are emitted with this conventional procedure. Alternatively, the right-hand side presents a "hydrogen route" in which iron ore concentrate is also used to produce pellets, but no fossil fuel is used for that.



Hydrogen is produced from water electrolysis on site or nearby using renewable electricity and is stored in large amounts to be used for two purposes: one is for the production of high-grade industrial heat and the other one is for the procedure of direct reduction of iron ore into metallic iron, which gives origin to sponge iron without using coke as a reducing agent, without using fossil fuels for heating, without deleterious environmental emissions, and also without having to convert the iron ore, the raw material, into liquid form as it has to be done in the blast furnace. The sponge iron is then used for crude steel production. Such a hydrogen route to produce direct reduced iron from pelletized iron ore is very innovative and encompasses a future vision of using hydrogen energy to clean the ancient and pollutant steel industry into an environmentally friendly one[22].

Most projects in the steel sector in the years to come refer to retrofitting, respectively modernization of existing plants to operate with hydrogen, thus representing challenges from a risk perspective not only linked to proper process design such as selection of materials, operational parameters, and safety systems, but also and especially to the use of existing components, and organizational / operational procedures.

Industrial heating

Industrial heating accounts for significant emissions today due to the extensive use of coal and natural gas, particularly for high-grade heat supply. Multiple decarbonization pathways exist, including biomass, direct electrification, post-combustion carbon capture and storage, and hydrogen combustion. Hydrogen has a key role to play in decarbonizing industry heat, in particular for high-grade heat (temperatures above 400 degrees Celsius) applications such as cement plants, glassmaking, and aluminum remelting.

In 2050, demand for hydrogen in industrial heat could account for about 70 MT, mainly in high-grade heating applications.

Hydrogen suppling the plant does bring with it risk and exposures, piping systems, equipment parts without safety function, equipment parts with safety functions, and subsystems all must be designed and or modified to handle hydrogen.

Hydrogen readiness concept comes with challenges that affect the plant systems and components.

Readiness can be broken down in 4 groups to determine if a unit is ready for hydrogen operation.

- H_2-Capable: The component or system is already fully capable to be operated under the expected boundary conditions after transition to hydrogen.
- Retrofitting: The component or system is partly capable to be operated under the expected boundary conditions after transition. Several parts must be replaced, but the system in total remains the same.
- Replacement: The component or system is not capable to be operated under the expected boundary conditions after transition. The component or system needs to be completely replaced.
- Obsolescence: The component or system is no longer required for the operation of the plant.

Key takeaways:

- Process integration, procedures and construction/operating standards are key to consider in industrial applications
- Ammonia, steel, and industrial heating are main areas of early development

3.2 Hydrogen for power generation

Gas turbine combustion

In the power generation sector, gas turbines will very likely need to burn H_2 or blended mixtures of H_2 and natural gas to reduce CO_2 emissions in the near future, while balancing other emissions (NOx), operational safety and efficiency.

The combustion characteristics of H_2 differ from natural gas and other hydrocarbon fuels which poses challenges for the design of hot gas path (HGP) components, especially gas turbine combustors. Hydrogen ignites/burns faster and hotter than natural gas, has a wider flammability area, lower ignition energy and a lower density. This will be a development process in phases, as Dr. Jeffrey Goldmeer, Emergent Technologies Director, Decarbonization, at GE Gas Power stated: "It is not going from zero hydrogen to 100% hydrogen, but the discussion in many places is with incremental shifts. So maybe it's 5% or 10% or 20%. And so, in that scenario, where we're going to walk our way up to 100% hydrogen."[23]

New types of combustors allowing up to 100% of hydrogen firing without the need for diluents for emission control are required and in development by all major manufacturers. Not all gas turbine manufacturers currently offer options for Natural Gas/hydrogen fuel mixtures but most of the major ones have developed combustion systems to handle off-spec gases to service markets such as steelworks off-gases (BFG, COG), IGCC applications, and bio- and waste-derived syngases. These off-spec gases include those with a high hydrogen content but also natural gas with higher fractions of H_2 and Methane.[24]

Compared to natural gas flames, hydrogen flames exhibit significantly different thermoacoustic behavior. This is due to higher flame speed, shorter ignition delay time and distinct flame stabilization mechanisms resulting in different flame shapes, positions, and different reactivity[24].

Risks derived from combustion dynamics (self-sustained combustion oscillations at or near the acoustic frequency of the combustion chamber) in modern gas turbines operated on hydrogen-rich fuels is expected to increase compared to natural gas operation

Flame speed of hydrogen is an order of magnitude higher than that of natural gas. Therefore, flashback is the dominant issue for modern lean premixed combustors on hydrogen fuel.

Flashback is the most severe concern around high H_2 levels in systems designed for natural gas, as the flame can propagate upstream and catastrophically damage hardware. The higher flame speed of H_2 increases the risk of flame propagation upstream closer to the injection points and into premixing passages, and "autoignition" when fuel spontaneously ignites upstream of the combustion chamber, in both cases burning in areas that are not designed for the highest combustion temperature. For dry low emission (DLE) combustors - the current industry standard - flashback and autoignition can cause failures of hardware in the combustor.

As reported in the Hydrogen Gas Turbine Report: "Heat transfer coefficients of combustion products fueled with hydrogen are higher than natural gas. Because the peak temperature in a gas turbine is controlled by heat transfer to the rotating turbine, this could necessitate a reduction in turbine inlet temperature as hydrogen levels increase,"[25] which would mean lower efficiency or it may result in higher requirements for materials and potential (long-term) damage to the hot gas paths components and/or reduction of lifetime.

Flame detection: Furthermore, it must be considered that hydrogen flames are hard to detect with standard UV systems. Therefore, flame detection systems specifically configured for hydrogen must be developed.[25]

"The main challenge of burning hydrogen is the danger of flashbacks, the reason is that hydrogens flame velocity and reactivity is 9-10 times higher than natural gas. Therefore, it is so difficult to optimize a combustor for 100% hydrogen and for 100% natural gas"

Retrofitting of existing devices

1,5 TW installed gas turbines capacity represent a huge potential, supporting a renewable dominated grid. There is no necessity to design and manufacture entirely new gas turbines for hydrogen combustion. Conversions would not only avoid large capital spending but also save time in switching large fleets of current gas turbines to hydrogen.

"Most of the equipment may be mostly or is already amortized, thus the delta in investments will make retrofitting interesting, also it needs to be considered that a power plant is not only related to the gas turbine, but to HSRG, steam turbine, switch yard, cooling systems and permits"[26].

Not all gas turbines will prove suitable for retrofit modifications to enable hydrogen combustion, in part or in whole. Redesign work with associated testing on older models, for instance, may not be justified compared to the cost of replacing the machine with a more up-to-date model for which the work has already been done[27]. When using hydrogen as fuel, it is of utmost importance to take into consideration the delivery pressure and temperature to avoid embrittlement in the pipelines and other auxiliaries. Changes may include new valves design with a different sealing arrangement, and potentially new piping material.

Also important is the incorrect purge of H_2 within the system. The more components involved, the higher the likelihood for some H_2 to remain trapped within them, leading to explosion risks when doing maintenance or repair. On that basis, proper measurement apparatus for H_2 traces should be considered as part of any H_2 use with GTs. In addition, purge systems using CO_2 or nitrogen must be taken into consideration.[27]

The installation of dedicated gas detection systems is a must as hydrogen is flammable and explosive over a very wide range of concentrations in air at standard atmospheric temperature (4 - 75% vol. and 15 - 59% vol. respectively). Accordingly, its handling becomes a major safety concern in comparison to natural gas.

Key takeaways:

- The combustion characteristics of H_2 differ from natural gas. For traditional combustor technology, the higher concentration of hydrogen makes the combustion less stable, increasing the danger of flashbacks and (lean) blow off as well as thermal pulsations and significantly altering the heat distribution in the combustion chamber
- Not all gas turbines will prove suitable for retrofit modifications to enable hydrogen combustion

4. Industrial and large-scale storage of hydrogen

Like natural gas or oil, hydrogen is exceptionally well-suited to store large quantities of energy for long durations due to potential energy being locked up in its chemical bonds.

Several methods currently adopted for hydrogen storage are:

- As a compressed gas
- As a cryogenic liquid
- Stored on the surface or in the pores of a material (adsorption)
- Chemically stored, bonded to other atoms/molecules (metal or chemical hydrides)

Key considerations for safety and risk management revolve around operating pressures and temperatures, material compatibility and fire rating, surrounding storage environment, leak detection.

4.1 Under pressure

Gaseous hydrogen storage systems typically require compressed gas vessels like tanks which can withstand pressures up to 700 bar. Liquid hydrogen storage on the other hand requires extremely low temperatures because its boiling point at atmospheric pressure is 253^{o}C.

The most mature and industrially utilized hydrogen storage method to date is compressed hydrogen gas in tanks/cylinders

Potential hazards for gaseous storage

- Difficulty in identification of hydrogen release as the gas is odorless, and colorless. The odorants cannot be added to hydrogen.
- Hydrogen can cause embrittlement of metals. This may result in the decrease of material strength and consequently in container's fracture, leading to a hydrogen leak.
- Accumulation of hydrogen, over a long period of time, in enclosures.
- An explosion driven by chemical reaction (combustion deflagration of detonation) or physical explosion (vessel overpressure)
- Formation of hydrogen-oxygen or hydrogen-air flammable mixtures. The intake of flammable mixture into a building ventilation system may lead to a deflagration or even to a detonation.
- High pressure hydrogen jets may cut bare skin.
- Hydrogen can be ignited easily as its MIE is 0.017 mJ (which is 10 times lower compared to other fuels). A static spark can ignite hydrogen released.
- When pure hydrogen is burning its flames are invisible in the daylight.
- Hydrogen burns rapidly and does not produce smoke.
- Possible puncture of storage vessel walls.
- External fire, heat or thermal radiation can cause a mechanical rupture of a tank due to the thermal decomposition of the polymeric and composite materials. The current value of fire resistance (publicly available) is up to 12 minutes before the catastrophic failure may occur.
- In case of a TPRD malfunction, a worst-case scenario is possible: a rupture (i.e. a catastrophic failure) of the hydrogen storage tank, producing a fireball, blast waves and burning projectiles.

4.2 Liquid form

A state-of-the-art form of storing hydrogen at large quantities in a restricted volume is to convert gas to liquid by cooling it down to very low temperatures. Hydrogen turns to liquid when it is cooled down to a temperature of -252,87 ˚C, at atmospheric pressure

LH_2 storage is subject to boil-off which can occur from several factors including residual thermal leaks, sloshing of H_2 inside the vessel, flashing from high pressure to low pressure, and conversion of ortho-to-para hydrogen inside the vessel. Boil-off requires the prevision of pressure relief devices and a boil-off system on LH_2 storage vessels and is a major safety consideration in design.

Potential hazards for liquid storage

- A loss of LH_2 containment. Damage to external tank walls can lead to the disruption of the storage vacuum, causing heating and a subsequent pressure rise inside a vessel. This should be avoided wherever possible.
- Formation of oxygen-enriched atmospheres. The condensed air may form oxygen enriched atmospheres in the vicinity of LH_2 storage. The solid deposits formed by condensed air and LH_2 could be enriched with oxygen. This poses a risk of explosion if the external wall tank is damaged. This mechanism is considered as a possible reason for powerful secondary explosions occurring during large-scale LH_2 release experiments at HSL.
- The boil-off. Pressure build-up is possible until the boil-off valves open.
- Ice formation. Low temperatures may result in ice build-up on the storage elements (e.g. in valves and dewars) leading to an excessive exterior pressure, and to a possible rupture of the vessel.

4.3 Solid form

Hydrogen can be stored in an alternative, solid storage format known as materials-based storage. This can be via adsorption of hydrogen onto surfaces of solids / inside porous materials or by being chemically bonded within solid materials (absorbed) to create chemical hydrides, this is sometimes referred to as chemical hydrogen storage.

This storage technology is still in the R&D phase and thus commercial delivery of these systems is in its nascency but will likely occur over the coming decade. Before considering large-scale applications, certain key parameters such as kinetics (cell performance), and the temperature and pressure of the charge and discharge cycles of hydrogen in these materials need to be mastered.[28]

Additional safety implications to be aware of are that metal hydrides are typically pyrophoric materials and will ignite spontaneously with air or water (the same as lithium-ion batteries). Thus storage vessels are required to be airtight. Vessels should also be designed with a safety margin to withstand the pressure of fully dehydrogenated material samples and/or be equipped with appropriate pressure relief devices. Other chemical hydrides may be more stable and not pyrophoric, but chemical safety data such as toxicity and accidental release measures of the storage chemical should be considered.

Adsorption based storage

Another method to increase the volumetric density of hydrogen is to adsorb it onto the surface of sorbent material with small enough pores. These types of materials can be thought of as "molecular sponges" that can densify the hydrogen to approach the density of liquid or solid hydrogen at lower pressures. Dr. Srikanth Mateti published in July 2022 a mechanochemical alternative, using ball milling to store gas in the nanomaterial at room temperature. It doesn't require high pressure or low temperatures.

Additional risks to consider for this form of storage is the chemical safety data related to the sorbent material used, and accidental release measures required. Before considering large-scale applications, it is also important to master certain key parameters such as kinetics (cell performance), and the temperature and pressure of the charge and discharge cycles of hydrogen in these materials[28].

4.4 LOHC (Liquid Organic Hydrogen Carriers)

In addition to the solid chemical hydrogen storage options mentioned in the previous section, research efforts to store hydrogen chemically in liquid carriers, such as liquid organic hydrogen carriers (LOHCs) or ammonia, have been conducted. Hydrogen can be safely stored in LOHCs at room temperature and atmospheric pressure before being extracted at locations for use.

4.5 Large scale storage

For storing hydrogen in large quantities there are mainly two ways, either in above ground vessels/tanks where the volumes normally can be up to around 1000 m^3 with operating pressures up to 1000 bar or in underground caverns with large volumes and operating pressures up to 250 bar. Compared to storage options on the surface, underground gas storage facilities can store much larger quantities of gas.

Rock caverns

Technologies for large-scale storage of gas in rock caverns are widely known, but for facilities for storing hydrogen, the technology has not been fully tried and tested. For example, in Halmstad, Sweden natural gas is stored in the mountain at 200 bar. It is 115 meters from the upper part of the gas storage to the rock surface.

First the lower part of the vessel is installed. The approximate 700 mm space between the rock wall and the steel shell is filled with compact (vibration free) concrete. Before the concrete work is done the steel vessel is filled with water to create a back pressure. The space between the mountain wall and the steel vessel is filled with self-compacting concrete. Alone the 12 – 15 mm thick steel plates will not withstand the pressure of 200 bar. But in cooperation with the surrounding mountain the steel plates will withstand the pressure.

The steel plates on the outside are cladded with a layer of bitumen. It operates as a sliding layer for the steel vessel to be able to move. The gas outlet is via a pipeline in a vertical shaft.

Salt caverns

Salt caverns are artificial cavities which are created in geological salt deposits. Future caverns are generally located at a depth of 500 to 1500 meters. To create such a cavern, it is first necessary to drill into the salt. The second stage consists in injecting water into the salt to dissolve it. The resulting brine (water mixed with salt) is extracted and leaves room for a large, tight cavern where hydrogen can be stored under pressure.

One of the issues is hydrogen leakage rate at high pressure. The effects of hydrogen leakage are the subject of many studies and is widely considered its greatest safety hazard. Both leakage and diffusion of hydrogen should be considered when equipping the storage plant. But further research should also be done on the permeability of the rock salt cavern wall. Important aspects are preventing leaks, controlling the behavior of the salt, and understanding gas thermodynamics

Potential hazards for cavern storage

- Tunneling and subsidence risks during construction and operation require special consideration.
- Metal alloy selection is critical when considering interactions with hydrogen and the potential for embrittlement which is why metals used with hydrogen should be selected in accordance with ASME B31 criteria.
- Will the vessel be in contact with the ground or protected by a coating and is that coating impervious to ground water and soil interactions? Galvanic interactions with soil must be considered and mitigated to prevent vessel failure.
- Will the vessel material be in contact or encased in concrete? Thermal expansion and contraction must be considered and the extent to which it may occur based on concrete and various metals having different thermal expansion coefficients.
- Pressure relieving device discharges should be directed to the outside atmosphere with consideration for personnel safety as well as the ability of the discharge to migrate back into the access tunnels/passageways.
- Relief valve testing and inspection frequency must be considered to ensure over-pressurization of the vessel does not occur.

- Maintenance practices, such as proper purge techniques and validation must be considered to ensure hot work activities do not endanger personnel or equipment.
- Access to the interior of the vessel, should the exterior be incased in concrete, for inspection and testing of the pressure vessel walls, to ensure the absence of corrosion and validating minimum wall thickness has not been exceeded, needs to be considered as part of the facility design and construction.
- Seismic activity of the area must be considered.
- Embrittlement is important to consider for materials selection, especially due to the required long lifetime of the components with limited possibilities to exchange.
- Cathodic protection, temperature influences for carbon, steel, and concrete.
- Hydrogen reactivity (such as with sulfur deposits) could produce undesirable reaction products including toxic materials

Key takeaways:

- Risks associated with hydrogen storage relate to leakage, rupture, and a failure to detect. Key factors are corrosion, embrittlement, valve condition, pressure relieving devices, purges, and procedures.
- Understanding gas thermodynamics is key for underground bulk storage.

5. Hydrogen transportation

Transporting gaseous hydrogen via existing pipelines is a low-cost option for delivering large volumes of hydrogen. The high initial capital costs of new pipeline construction constitute a major barrier to expanding hydrogen pipeline delivery infrastructure. Research today therefore focuses on overcoming technical concerns related to pipeline transmission, including:

- The potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines
- The need to control hydrogen permeation and leaks
- The need for lower costs, more reliable, and more durable hydrogen compression technology.

Potential solutions include using fiber reinforced polymer (FRP) pipelines for hydrogen distribution. The installation costs for FRP pipelines are about 20% less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel, minimizing welding requirements.[29]

Risks associated to the use of existing (natural gas) pipelines

Utilizing existing pipelines for the transport of Hydrogen presents risks that may not have been considered when the original pipeline was installed.

Hydrogen has a small atomic structure and can penetrate and leak from materials of the existing pipeline not originally designed for hydrogen

Erosion and corrosion of an existing pipeline would have to be determined to assure safe transport as well as life expectancy of the pipeline. Postulated accidents would have to be evaluated and their potential for harm to the public, depending upon the location and proximity of the pipeline to public causeways. While there may be short term savings in utilizing existing pipelines, the long-term costs related to maintenance, enterprise interruption, and product loss should also be considered in project development.

Any introduction of a hydrogen blend concentration would require extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices (e.g., integrity management systems).

The durability of metal pipes degrades when exposed to hydrogen over long periods, particularly in high concentrations and at high pressures.

Leakage

The permeation coefficient of hydrogen is higher through most elastomeric sealing materials than through plastic pipe materials. However, pipes have much larger surface areas than seals, so leaks through plastic pipe walls would account for the majority of gas losses. Permeation rates for hydrogen are about 4 to 5 times faster than for methane in typical polymer pipes used in natural gas distribution systems. Leakage in steel and ductile iron systems mainly occurs through threads or mechanical joints. Leakage measurements from GTI for steel and ductile iron gas distribution systems (including seals and joints) suggest that the volume leakage rate for hydrogen is about a factor of 3 higher than that for natural gas.

Hydrogen is more mobile than methane in many polymer materials, including the plastic pipes and elastomeric seals used in natural gas distribution systems

A calculation based on literature data for the permeation coefficient of hydrogen and methane in polyethylene (PE) pipes suggests that most gas loss would occur through the pipe wall, rather than through joints, in distribution mains smaller than 2 in. and operating at 60 psig (5 bar) or higher.[30]

Pipeline racks (underground and aboveground)

While some pipelines are located above ground, the main parts are usually concealed underground which allows them to reach more places without interfering with buildings, homes, and areas of greenery.

Most common causes of pipeline incidents (35%) involve equipment failure.

For example, pipelines are subject to external and internal corrosion, broken valves, failed gaskets, or a poor weld. Another 24% of pipeline incidents are due to rupture caused by excavation activities, when heavy equipment accidentally strikes a pipeline. Overall, in the US, pipeline incidents are most common in Texas, California, Oklahoma, and Louisiana, all states with considerable oil and gas industry[31].

There are two types of pipeline incidents: leaks and ruptures. A leak is a slow release of a product whereas a rupture is a breach in the pipeline that may occur suddenly. In general, leaks are more common, but cause less damage as opposed to ruptures that are relatively rare but can have catastrophic consequences. Pipelines are low frequency / high severity risks, meaning that incidents are relatively rare considering the total mileage of pipelines and the volume of product transported, but when incidents do occur, they often have catastrophic consequences. There are several causes of pipeline incidents including corrosion, excavation damage, incorrect operation, material/weld/equipment failure, and natural force damage (i.e., Hurricane Katrina)[32].

Risks associated with buried piping:

- Even after applying mitigating measures such as external coating and cathodic protection, buried steel pipes are subjected to external corrosion.
- Draining, cleaning buried pipes is difficult compared to an aboveground pipe.
- Leak detection and repair of buried pipes is a difficult and expensive exercise. Modern underground pipeline leak detection systems are available, but they are very expensive to install.
- Buried pipes are subjected to mechanical damage when soil excavation work is being carried out in close vicinity.

Risks associated with aboveground piping:

- Above ground pipes could be subjected to vehicle impact exposure both in terms of road crossing when impacting the rack but also the pipe rack support columns if not protected properly.
- More exposed to natural hazards like hurricanes.
- More exposed to pipeline vandalism and sabotage.
- In terms of total cost, installing pipes above ground will be more expensive because you must consider the foundation, structural steel elements and support elements included in the project.

Key takeaways:

- The durability of metal pipes degrades when exposed to hydrogen over long periods, particularly in high concentrations and at high pressures
- Hydrogen has a small atomic structure and can penetrate and leak from materials
- Plastics are less susceptible, but are permeable

6. Risk mitigation

Facility design and construction

There are multiple codes and standards that are required by governmental agencies when designing a hydrogen facility. Annex 1: Regulations, standards, and codes provides an overview of relevant regulations and design standards.

Additional factors should be considered while designing a facility and determining what types of process, materials and procedures are selected. The structure and safety equipment that comprise the facility should not be underestimated while designing in regards of long-term operation and safety and the same applies for risk management measures and procedures.

Designing the facility with multiple trains of operation is not only a good way of maintaining production while maintenance is performed, but a great mitigation measure both for material damage and business interruption. Best practice is separating the trains in different fire areas.

Retrofits and decarbonization projects in existing facilities should consider that the site was not originally designed for hydrogen operations, this not only in regards of process and components but also relating to organizational and safety issues.

Geographical location must be considered when designing for seismic response of the facility. Not only in regards of process operability, but seismic design criteria should also apply for any other peripheral and safety equipment that has the potential to cause a major event. The ancillary equipment does not necessarily have to meet full seismic design criteria but at least it should remain in place during a seismic event. An example would be a sprinkler system that is installed over hydrogen process equipment. The design should be such that the suppression piping does not dislodge and drop onto the hydrogen equipment.

Material selection

Piping, tubing, valves, and fittings shall be designed and installed in accordance with applicable sections of ASME B31, Code for Pressure Piping, and Sections 704.1.2.3, 704.1.2.4, and 704.1.2.5 of the ICC International Fuel Gas Code (IFGC) and/or equivalent.

Cast, ductile, malleable, or high-silicon iron pipe, valves, and fittings shall not be used.

Material properties, such as stress and strain limits, must be understood when selecting metal alloys to be used within the hydrogen systems. Temperature and pressure effects that the systems will be subject to, must be considered when selecting the appropriate materials. If it is known that a specific process must be controlled at specific modes of operation to prevent damage, then detailed operating procedures as well as other safety measures, such as electromagnetic relieving devices (controlled by a program that monitors the system parameters) must be implemented.

A common issue for hydrogen storage, transportation and usage is deterioration, embrittlement, and cracking of materials due to the contact with hydrogen. Hydrogen embrittlement involves the diffusion of atomic hydrogen through a materials microstructure where it may form brittle metal-hydride pockets or recombine to make small pressurized H_2 bubbles throughout the material. Both of which can result in increased internal pressure, propagation of cracks, and decohesion of internal material surfaces, loss of ductility and toughness.

In general, hydrogen damage occurs at a stress level below those typically experienced for a particular metal in an environment without hydrogen, and is affected by the pressure, purity, temperature, exposure time, stress level, strain rate, material microstructure, strength, and permeability.

Various materials are used in the equipment and pipelines of today's natural gas networks, for instance, stainless steel, carbon steel, cast iron, copper, plastics, and elastomers, and some are more tolerant to hydrogen than others. These materials and the components/equipment such as storage tanks, pipes, compressors, valves, and meters need to be tested to understand and mitigate the risk of component failure associated with hydrogen exposure.

No structural metal can be labelled as "immune" to hydrogen embrittlement, each metal has a varying degree of susceptibility. Thus, in designing structures for hydrogen service, one cannot simply select a material from a list of hydrogen-compatible alloys[33]

Hydrogen embrittlement is most known and observed in steels, particularly steels that have a pearlitic phase. Typically, it occurs below 95°C as it can remain dissolved within the steel at or below this temperature. Generally, high-strength steel (>100 ksi yield strength) used in high-pressure transmission pipelines is more susceptible to hydrogen induced brittle fracture or catastrophic rupture.

On the other hand, low-strength (carbon and low alloy) steel commonly used in low-pressure distribution system is subjected to loss in tensile ductility or blistering that assists ductile fracture in hydrogen containing environment. Carbon and low alloy steels also show accelerated fatigue crack growth and degradation in endurance limits when exposed to hydrogen. As a result, fatigue is also a concern for these materials when a pipeline experiences pressure fluctuations even at relatively low pressures.

For both high- and low-strength steels, hydrogen concentration and operating pressure are the most critical factors[34]

In addition, fracture within steel can also lead to an increased rate of hydrogen reaction and subsequent corrosion[35]. Ductile iron, cast and wrought iron, and nickel steels (2-9%) are not acceptable for hydrogen service components.

Embrittlement induced crack, Photo by CEphoto, Uwe Aranas[36].

Steel that has the equivalent microstructure to sour service steel should be used for new H_2 pipelines.

Austenitic stainless steels have been used successfully in high-pressure hydrogen gas piping and pressure vessels tend to be the most resistant and offer the best performance for hydrogen gas and liquid service structural components. For future 100% hydrogen service pipelines, "Sour Service Steel" that complies with ASME B31.12 Appendix G is recommended[37].

"Sour service" piping refers to pipes that are exposed to H_2S (hydrogen sulfide) and a wet acidic environment. These steel pipes tend to receive accelerated hydrogen embrittlement due to a chemical reaction of the H_2S and the acidic environment, and thus the microstructure of the steel is designed to have the higher level of resistance to hydrogen embrittlement. However, for hydrogen service piping, conditions are different to sour service conditions. H_2S should not be present, thus the chemical reaction of H_2S generating H diffusion should not occur with just pure H_2 gas. Therefore, H_2 service pipes should see a lower absorption of H_2 in the steel by comparison.

Recent research suggests that under hydrogen service conditions (20-100 bar H_2, 25-80°C, wet and dry) H_2 absorption into sour service steels is ~ 5% of that found in NACE solution A sour service conditions (exposed to H_2S)[38]. Furthermore, none of the sour service steel specimens exposed to 100 bar H_2 broke when constantly loaded at 90% of the specified minimum yield strength.

Other metallic materials such as copper have a low permeability to hydrogen, however, if oxygen is present in its structure, this can induce hydrogen embrittlement fractures. Coppers with very low oxygen contents are available. For aluminium and its alloys, assessment data is limited, however, information indicates that aluminium and its alloys are highly resistant to embrittlement in dry environments only, thus care to remove water vapor from hydrogen streams is important when considering aluminium components.

Hydrogen has little or no interaction with plastics and elastomers used in low-pressure distribution pipelines or well sealing. Diffusion or permeation of hydrogen through these materials, however, is of higher rate that increases the leakage. Additionally, the build-up of electrostatic charge in plastic hydrogen service components is to be considered.

Hydrogen permeation barriers are a method of prolonging the service life of hydrogen service components. These are thin coatings that could be applied to the surface of materials. Data is limited, but materials with low permeabilities include beryllium, titanium aluminium nitrides, chromium oxide and silicon nitride[39].

Finally, when assessing existing pipelines compatibility with H_2, the mistake of assessing the pipeline by its age alone is incorrect, and it should be assessed by the steels Microstructure and compatibility in accordance with design codes. Many recent lines will have been made with higher C ferritic pearlitic steel as well as the old ones and therefore would have a higher degree of susceptibility to hydrogen embrittlement.

Compression

The much lower molecular weight and heating value of hydrogen relative to natural gas has implications on the type and design of compressors used in H_2 compression. Reciprocating compressors are currently the most efficient solution, but they are not able to handle nearly as much gas volume as centrifugal compressors. Because of the lighter weight of hydrogen, to achieve a pressure ratio comparable to an existing natural gas line, the rotating speed, and the number of stages of centrifugal compressors need to be higher.

The higher speed may further demand impeller designs using high-strength titanium alloys, a type of design not yet commercially available. For 10% H_2 mixture, the existing compressors can be operated without any significant changes. When the H_2 volume is under 40%, the compressor housing can be maintained, but the impeller stages and gears may require adjustment.

For pipeline systems with greater than 40% H_2 content, the entire compressor must be redesigned[40]

Hydrogen embrittlement certainly attacks metal components in a compressor causing cracks and reducing service life, as seen on an impeller in the right figure[40]. For highly stressed rotating components like impellers, embrittlement is a particular concern. While titanium alloys offer excellent strength, they are subject to hydrogen embrittlement just like steel alloys. To avoid this failure mechanism, impellers may require reliable surface coatings and enhanced inter-stage cooling to achieve better component reliability.

Embrittlement induced crack in rotating machine. Source: Turbomachinery International[40]

Embrittlement can be classified according to the root cause in Internal Hydrogen Embrittlement (IHE), Hydrogen Environmental Embrittlement (HEE) and Hydrogen Reaction Embrittlement (HRE)

Leakage, fire, and explosion

Relative to natural gas, hydrogen has a greater tendency to leak through valves, gaskets, seals, and pipes, and risks associated with accumulation in confined spaces from those leaks could require additional monitoring/detection devices.

The leakage of hydrogen in steel and ductile iron systems mainly passes through the threads or the mechanical joints, at about a three times higher rate than natural gas. In addition, hydrogen is more mobile in plastic and elastomeric materials, with a permeation rate about 4-5 times that of natural gas through plastic pipes, and even a higher rate through elastomeric seals. The amount of gas loss may be negligible from an economic point of view, but gas leaking in a confined space may increase H_2 concentrations to levels that may become threats from the safety standpoint[34]. Besides newly developed materials that can be used as a replacement, lower pressure, and temperature in general will reduce the leakage.

Regarding fires from leaks, hydrogen covers a very wide flammability. In air at standard temperature and pressure, it ranges by 4-75% by volume. In addition, the detonability range in air is 18-59%. Thus, the potential for dangerous hydrogen mixture levels in air from a leak or accidental release is high. Hydrogen is odourless and colourless, which is why leaks are hard to detect. Scent compounds such as mercaptans used in natural gas cannot be added to hydrogen streams as this can poison fuel cells or other equipment. Autoignition temperature of hydrogen is observed above 510 ˚C (higher than most long-chain hydrocarbon fuels). Thus, one should be aware equipment or objects hotter than 500 ˚C in contact with hydrogen-air mixtures could cause ignition.

The minimum ignition energy is very low, 0.017 mJ, ~16.5 times lower than methane. Thus, even electrostatic discharge is sufficient to ignite mixtures close to the flammability limits. Because hydrogen is dielectric, hydrogen flowing in a pipeline or agitated in a vessel can cause a build-up of static charge, thus all equipment conveying hydrogen must be completely grounded. Ignition can be caused by various sources, including:

- Hot surfaces
- Electrical arcs and sparks
- Electrostatic discharge (i.e. underground particle filter)
- Atmospheric discharge (lightning)
- Mechanical friction or impact sparks (i.e. rapidly closing valves)
- Electromagnetic radiation
- Ultrasonics
- Adiabatic compression (shock waves)

- Ionizing radiation
- Optical radiation
- Chemical reactions or catalytic particles
- Open flames

In addition, low flame visibility and lack of odor of H_2 gas makes both ignited and unignited leaks hard to detect.

The major safety asset of hydrogen when compared to hydrocarbon fuels, is that it has the highest buoyancy on earth. This means at the scene of accidental release, it possesses the ability to rapidly disperse/flow away from the scene, diluting with air to safe flammability levels[41].

Fire protection

Hazard analysis is a key element for hydrogen plant construction, operation, and maintenance.

Investing in identifying and mitigating known hazards during the design phase, as well as those that may present in the future operation is probably the best fire protection measure

Knowing and understanding how a fire may arise and propagate is key.

Hydrogen represents a major risk regarding fire and explosion. Building construction materials and compartmentalization of areas can be evaluated for fire resistance and the ability to isolate the fire for a specific duration of time. Areas of potential hydrogen accumulation from system leakage should be evaluated for damage to the structure related to a hydrogen explosion. Key questions are:

- Can the structure walls withstand the explosion shock wave?
- Is the structure able to relieve the pressure increase via blow out panels?
- Does the facility have appropriate ventilation to prevent the accumulation of hydrogen?
- Are passive blowout vents in place?
- Where does the ventilation discharge?
- Additionally, is there a dedicated fire brigade on site? What level of training do they have?
- If not, how long would it take for the local fire department to respond?

The location of the ventilation discharge is as important as having the discharge. It is important to evaluate the location of the discharge to ensure enough distance from other intake and/or ignition sources. Early detection is a further key element to preventing either an event from occurring or minimizing the effects of the event.

Best practice is to install systems that will detect hydrogen prior to the levels reaching the lower explosive limit, minimizing the risk to operations and personnel

Suppression systems should be fit for purpose. When designing a gaseous suppression system, one must also consider its effects on humans in the event of discharge.

Regular inspection and testing of suppression systems is mandatory

General prevention and mitigation measures for H_2 fire and explosion protection to consider include:

- Absence of ignition sources
- Avoidance of confined spaces
- Provide natural ventilation, in absence of this, use forced ventilation at a rate high enough to dilute hydrogen leaks to 25% of the lower flammability limit.
- Use active detection measures
- Provide adequate separation distances between hydrogen vessel stacks/conveying equipment and infrastructure
- Fire and explosion barriers
- Emergency response plans
- Shut-off and isolation response in event of an accident

Operation and maintenance

Procedural adherence is most relevant to safely operating and maintaining a facility. The procedures must address human factors as well and safety considerations. The facility must also consider ancillary processes, such as storage of materials, that could affect operations and must address those as well through procedures for the facility. How and where transient combustible materials can be stored should be addressed to minimize the risk of their involvement in a fire which could potentially make the fire larger than the installed system is designed to mitigate.

When large losses occur, it is not uncommon that these are a combination of technical and human errors. Minimizing the risk of human errors increases the probability of minimizing the loss, or at least decreases the effect of the loss.

Operation of hydrogen systems, in working with a very flammable and explosive gas, requires a high level of procedural compliance which should be well documented and frequently updated.

Important areas of operation are:

- Startup and shutdown procedures
- Emergency procedures
- Inertization
- Leakage control
- Flange management
- Drainage
- Combustible control
- Labelling of piping and equipment
- Operator training program

Safety plan documentation and implementation, training of staff prior to accessing the site and regular inspections as well as internal/external audits are highly recommended.

Startup and shutdown of process units which include hydrogen plants are not always routine since the turnaround frequency can be several years and for a shift operator it could be that he/she is not working during that period. This means that it can take several years before operators are involved in a certain startup- or shutdown specific step/task. It will also take several startups and shutdowns before the operators are familiar with the procedures and can feel confident.

Having clear startup- and shutdown procedures will minimize the risk of operators making mistakes

The procedures/instructions should be written in local languages with step-by-step instructions preferably connected to valve tag numbers, pump numbers etc. The instruction should be a part of the operator training and referring also to P&IDs and PFDs. Startup and shutdown instructions should be available in paper form in the control room and updated based on MOC or similar from changes in the process or surroundings.

In the event of an emergency the stress level will be high, it is easy to make mistakes and/or to miss something which can increase or delay the emergency event. Emergency instructions are an important tool for the operators to lean on during an exceptional event. The emergency instructions should cover events like fires, power failure, loss of cooling water, loss of instrument air etc. The instruction should be based on PHA and risk analysis connected to the different events.

Emergency instructions should be available in paper form in the control room and reviewed and updated annually

A part of the startup and/or emergency event is Inertization of the process unit and connected systems. Inertization is done before startup and shutdown of all systems that contain flammable gas. If hydrogen is introduced to an environment containing oxygen, there is a significant risk of fire/explosion, especially due to the wide explosion range of hydrogen. Hydrogen burns/explodes in 4 – 75% gas/air mixture. The purging should be done with an inert gas, for example nitrogen. Before startup after for example a maintenance shutdown, the system needs to be free from oxygen and purged to the atmosphere (not to the flare system since it can contain oxygen). The system is normally purged until the oxygen level is at least below 0,5%vol. This can be done by pressurizing the systems with the inert gas to 5 bar and releasing it down to 0,5 bar. This is done repeatedly until the oxygen level is low enough.

After shutdown the system is inertized in the same way, but since the gas does not contain oxygen, it can be released to the flare system (if there is one). Otherwise vented at high elevation not exposing surrounding systems or persons.

Before any assembly is performed LEL-measurements should be made to verify that the system is free from flammable gas. Note that any human entry into the systems require additional measures

It is important to include all systems that will be exposed to flammable gas including dead ends and pipelines. If the unit is connected to a flare system, it is normal procedure to purge nitrogen and flammable gas into the flare system. No air or oxygen should be purged into the flare system due to the risk of getting a flammable mix with explosion as potential consequence. If a flare system exists all safety valves containing flammable gas should be connected.

Another important management procedure before startup is to have control of flanges and other dismantling works. Installing the wrong gasket (size or pressure class) can lead to leakage and fire.

A flange management system where all flanges are checked in a structured way after assembly is required, controlling the right type of gasket in terms of size and pressure class, right length of bolts tightened correctly will minimize the risk of leaks during startup

After each flange has been correctly checked, it is recommended to have sealing on the flange to ensure it has not been broken after the check. Leakage control should also be done as a part of the startup procedure by pressuring the system first with an inert gas. When the pressure is set, for example at 7 bar a trend curve can be set in the DCS to follow any pressure decrease at a certain time.

At the same time leak spray should be used on flanges valves etc. Any noted leaks should be corrected, and the systems tested again.

Before unit start up the process areas should be free of combustible material. This should be checked as part of the startup procedure before any flammable gas or liquids are introduced into the unit. During operation, a part of the housekeeping routines, is to make sure that the process area is free of combustible material.

Drains and vents connected to flammable gas or flammable liquid should during operation be capped. This should be reviewed during the normal safety rounds in the plants.

Process systems should have a high level of labelling of piping and equipment with color codes for different media with flammable gas/liquid tags when applicable. Labelling of piping with media- and risk type helps identifying risks in the event of a leak or other type of events. Also, labeling of equipment with signs and valves with tags helps operators when used together with instructions and training connected to P&IDs and PFDs.

Training programs for operators is especially important when working with high-risk type of production. Specified classroom training for operators with mentor program and if possible, simulator training is key to reaching a high level of operator knowledge. Before operators start to "work alone" some type of knowledge test can be an option to determine if the operator is ready for the task.

A hot work program must be implemented at the facility to minimize the probability of an event occurring. Hydrogen represents a risk to be mitigated even without the presence of an ignition source. Introducing a maintenance process that purposefully applies heat to the process equipment requires specific controls and processes to reduce risk and prevent equipment and personnel injury that could result from either a hydrogen fire or explosion. The type of tooling that is used at the facility should be considered. Non sparking tools should be used when working in areas where hydrogen could be present.

Equipment manufacturers generally specify a frequency at which either preventative maintenance should be performed, or parts should be replaced. Obtaining experience through performance and maintenance data could help to reduce maintenance costs by transitioning to a performance-based maintenance schedule. Replacing a part or calibrating an instrument well before it would present operational issues not only reduces out of service time and material costs, but also the overall man-hours required to maintain the facility.

Annex 2: Summary of best practices and risk mitigation for hydrogen facilities is a checklist for assessing hydrogen project, the table is not exhaustive but may help identify known safety issues

Key takeaways:

- Codes and standards are the minimum requirements that must be followed, not always best practices
- Investing in identifying and mitigating known hazards during the design phase, as well as those that may present in the future operation is probably the best fire protection measure
- Adherence to operation and maintenance procedures of hydrogen units with its connecting systems are critical since both technical- and human errors are potential large risk exposures
- Currently, no structural metal can be labelled as "immune" to hydrogen embrittlement

7. Underwriting considerations

Risk evaluation

In general, underwriting technical risks is a difficult task for any seasoned insurance underwriter let alone the novice underwriter. Imperative for any underwriter embarking on such a task is possessing a degree of technical knowledge of how that risk operates (i.e., how hydrogen is processed). In part, engineering review and inspection provides the fundamentals and basics of any technical risks from which underwriters develop knowledge of potential material issues and exposures. Ultimately, the underwriter will need to determine the overall insurability of any potentially troublesome technical risk. Hydrogen production and storage certainly falls into that category demanding the technical best from both an Engineering and Underwriting standpoint.

Electrolyser technology is challenging regarding insurability with constant new developments and significant scaling up expected in the years to come. As such Underwriters and Engineering together need to keep up with the fluid technology evident in the fast progression of this renewable energy class.

While many of the innovations may represent improvements in operational stability, robustness, and safety, others are just plain difficult to assess to ultimately determine proven status definition.

Since most OEMs are planning scalation steps of factor 10-20, it is important to differentiate between the following factors: a parallelization of existing/proven equipment; major changes in the applied technology; increased process parameters; and exhausted operational limits.

It must be noted that for the foreseeable future, industry standards are going to lag technological development and that so far there are no trusted standards for the certification of hydrogen technology. All these factors will demand strict underwriting attention with the expected wide-spread development of this multi-faceted renewable class.

The significant peripheral and ancillary components common with Hydrogen production/storage will also demand special underwriting attention

Depending on the scale of electrolysis, the electrical equipment can be complex and expensive representing a potential high degree of exposure from both a Property Damage and Business Interruption perspectives. Hydrogen storage will certainly be PML relevant involving both systems integrations and process logic. Notice should be also directed to those downstream associated risks (receivers) which may rely on consistent supply for H_2 for operations. When it comes to the complex downstream integration of hydrogen projects, there is clearly a need to certify entire projects (i.e. value chains) rather than just individual components (e.g. electrolysers). But in the absence of standards, one must rely on other key drivers of risk quality. OEM & contractor experience

One important factor to consider when underwriting a Hydrogen risk is overall Original Equipment Manufacturer (OEM) experience.

Traditional equipment manufacturers may be in a better position to both scale up proven and implement unproven technologies compared to disruptors (or those OEMs relatively new to the industry)

Another critical factor involves the actual General Contractor (or EPC) contracted for the specific project. Is the selected GC well-versed with this class? Do they have a 'Hydrogen' history under their belt? By and large, Insurance carrier Engineers will focus on ALL the players involved with these Hydrogen projects to determine experience in this developing space and overall acceptability - Owners, GCs, Subs, Engineers, Architects & Designer, etc.

The Owner of the project is also a critical underwriting factor. Again, does the owner have adequate experience in this space? Do they have similar past projects under their belt? Have they worked with the selected GC before on similar projects? Are they financially viable? Experience is vital to the success of any project.

Other relevant issues when evaluating insurability are catastrophic exposures; adjacent property risks; lifetime of critical components; warranties on critical components; expected refurbishment time; recovery time after catastrophic events; contingent interdependencies; spares for critical equipment; lead times for critical spares and availability of; and geotechnical conformance.

Attending pipeline support (Existing or New) is also a critical feature of any hydrogen project requiring careful underwriting review. Any repurposing, common with hydrogen projects of scale, requires evaluation of the existing pipeline materials and condition of valves. Though technically challenging polymer linings may be a suitable option in the end.

Third party inspections, audits and certifications are a key element for validating escalation and improving operational safety

Subjective risk: Driven by operator and project owners

- Organigram: experienced management
- Contractors: experienced, track record
- Strong Risk (HSE) involvement and awareness
- Adherence to procedures and standards, continuous improvements, lessons learnt

DSU risk: spare parts, lead times, redundancy

Critical to all technical risks is the spare parts inventory for critical equipment and the lead times to replace such equipment. Delay in Start Up (DSU) is a critical cover in demand on most technical builders' risks offering Business Interruption restitution for losses triggered by a PD loss to key equipment. Owners will most likely be seeking loss of profits with Contractors seeking soft costs for additional expenses incurred as the result of a loss. Underwriters must be aware of these exposures and somehow mitigate the magnitude and material consequences of such a DSU loss.

Hydrogen electrolysers and their main components (including compressors and transformers) may take 12 to 24 months to replace

No doubt, an adequate waiting period for DSU should be applied from an underwriting standpoint to address this issue. DSU coverage is not an easy cover to underwrite on technical risks of this nature. DSU values may be determined in numerous ways. There are numerous reporting methods based on a variety of factors - profit schemes, proforma showing monthly breakdown of revenue and cost streams, debt service, fixed costs and, of course, soft costs.

In any case the underwriter needs to carefully determine what exactly the insured is seeking from a restitution standpoint should the project suffer DSU loss. There are a variety of conditions influencing a DSU loss. As such it's imperative the underwriter (and risk engineering team) runs a variety of loss scenarios particular to a DSU loss event.

Other key questions are: What are the key triggers/key equipment? Are they linear in nature, seasonally impacted, or front/back loaded? Are long term agreements in place based on a fixed cost or will it be open market variable price? Can another existing plant pick up the lost capacity if there is a delay? Are spares available? What is the supply chain situation?

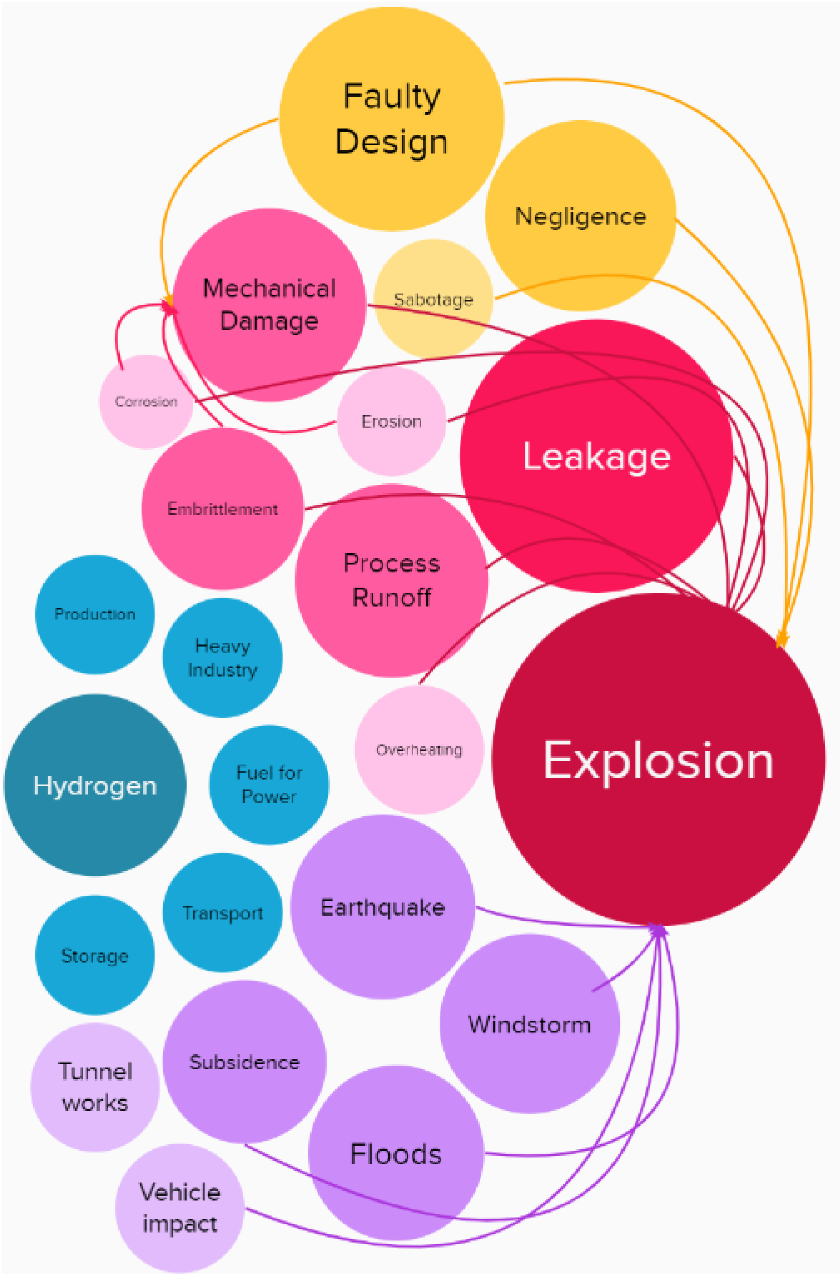
DSU is a critical cover for both the Insured and the carrier. As such, attention to detail is necessary from all parties to navigate this material cover. The fluid and volatile nature of this class demands all stay on top of any future developments whether positive or negative. The proper underwriting of hydrogen with all its peculiarities will be a work in progress for many years to come

Aggravating factors: risk mapping

While mapping the main risks associated with hydrogen applications, the following conclusions were drawn:

- Risks associated to design, especially to material selection (and operating parameters) such as embrittlement, corrosion, erosion can be considered as risk clusters relevant to all hydrogen applications
- The main exposure explosion, which increases sensibly the relevance of high design standards, detection systems, leakage control, and operational excellence
- Higher exposure and rather severe worst-case scenarios derived from natural catastrophes compared with fossil-based feedstock
- The same applies for the human factor, negligence, malicious damage as well as cyber exposure can rapidly aggregate to catastrophic explosion scenarios. Access control, work and safety procedures, and cyber-security are more important than ever before.

A growing number of applications are being investigated and developed, implemented, and scaled up. The prototype nature of most applications will remain for many years.



Hydrogen risk mapping showing relevant risk cluster and interdependent causality

This aggregative nature should be considered not only in regards of risk selection, but also while structuring coverage, pricing risks, and performing risk engineering assessments. While the insurance industry will face some non-assessable risks in the years to come related to prototypes, scale-up, aging, lifetime of components, etc., some others known risk elements such as safety standards, detection, and firefighting systems, etc. should be carefully and actively addressed to assure manageable and fair risk transfer in a hydrogen-based economy.

PML Considerations

Possible Maximum Loss (PML) considerations are key for adequate pricing and underwriting of H_2 risks. Obviously PML exposures vary across the different phases of a project. Large parts of the construction phase are characterized by lower build-up in values, but lack of protection and safety systems due to the unfinished state of the project. Values typically peak during testing and commissioning as well as during the operational phase which ultimately drives PML exposure. For the sake of this chapter, we will look at PML scenarios assuming peak values:

Internal scenarios

Internal PML is driven by technology immanent factors and typically related to key components which have a high value and are bottlenecks for the business. These are:

- Electrolyser runoff, gasifiers, fire/explosion due to disintegration of product compressor incl. propagation. High pressure gas release with flash or jet fire in the compressor damaging adjacent equipment depending on the spacing. Lube oil system fire.
- Ammonia plant – Reformer explosion or vessel disintegration in the high-pressure ammonia synthesis reactor or the urea reactor. Lube oil system fire within the compressor.
- Methanol Reformer – fire or explosion in the reformer due to hydrogen embrittlement or disintegration of the methanol synthesis reactor. Lube oil system fire within the compressor.
- Pipelines - Incorrect backfill leading to excessive settlement which requires replacement of a certain length of backfill – Welding failure with improper alloy and lining damage or insulation failure while the pipeline is buried. Flood of an open trench section of the pipeline. Micro TBM or HDD could get stuck or collapse of the tunnel for the pipeline. External coating or paint failure leading to a corrosion issue. Damages at main compressor stations.
- Explosion at main product storage (identify and mitigate larger H_2 volume).
- Other risks: serial losses resulting from defects of key elements such as welding, coating, and membranes.

The actual PML scenario is driven by the extent of the damage, which will, among other factors, depend on the layout of the project and the cost of repair (PD) respectively the indemnity period (DSU/BI). As many H_2 risks are built in modular forms, plant layout is crucial to determine a reliable PML scenario.

On the positive side it must be noted that the modular layout of projects can ensure special distance as well as redundancy which mitigate PD as well as DSU/BI risks. Also, H_2 is lighter than air which means that, unlike other explosive gases, it will not accumulate at ground level potentially leading to vapor cloud explosion (VCE).

External scenarios

External PML scenarios to be considered:

- Loss resulting from existing property; Vapor cloud explosion (VCE) caused by a nearby refinery or petrochemical complex.
- Nat Cat events: Fire, explosion due to natural catastrophes (earthquake, windstorm) but also major damage due to floods / ensuing floods. Electrolyser internals should be able to withstand (since

pressurized) water intake if switched off timely but cleaning works and down time relevant. Consider also secondary natural perils.

- Earthquake: rupture of pipelines and tanks leading to fire and explosion, transformer damage.
- Flood: flooding of electrical components such as electrolysers.
- Secondary perils: damage cause by wildfire, tornado, torrential rain, lighting strike.
- Terrorism & Cyber: H_2 projects can be part of critical infrastructure which can be subject to both Terrorism and Cyber-attacks both of which are capable to induce high PD and DSU/BI losses.

Underwriting best practice

In reaction to the new challenges posed by the H_2 industry, solid Underwriting is required. The following underwriting considerations are by no means exhaustive and will require constant rethinking, but they should serve as best practice to address key risk areas:

Prototypes / Defects: Defect coverage should be carefully considered on the basis of the technology in scope. The power and renewables industry has set basic standards to align defects cover with technology risk. Covering damage resulting from defects may turn out to be costly and highly disputed, this is dependent on the maturity of the corresponding legislative framework (wording definitions, assessment of loss and associated costs, responsibility, and subrogation rights).

For prototypical technology and scaling up comprehensive wordings (such a Munich Re CPI) to adequately reflect special components, topped with an adequate LEG clause or corresponding endorsements to achieve the same result. There are robust experiences with the adaptation of LEG clauses to specific technology risk in the market (e.g. gas turbines, wind turbines) and it sensible that hydrogen is treated accordingly:

- LEG 1 is recognized as a standard for prototypical elements, meaning technology which has no type certification.
- LEG 2 is recognized as a standard for type-tested, but unproven equipment. Equipment is typically defined as unproven if the fleet leader has not yet reached a specified number of operating hours (typically 8,000) without incidents
- LEG 3 is typically offered for proven technology only, that is for type-tested equipment where the fleet leader has operated for a specified number of operating hours (typically 8,000) without incidents

Basis of indemnity: This is crucial in many aspects given that (1) membranes, catalysts, hot gas path components, refractories and other components have limited lifetime which depend on the operation regime and (2) there may be pre-used/refurbished equipment in overhaul/retrofitting projects which should be analysed in terms of depreciation. Best practice is to assess an equivalent operating hours scheme for components with limited lifetime and/or expected high degradation and to have clear and adequate depreciation wording agreed

Corrosion / Erosion / Embrittlement: H_2 projects are subject to corrosion, erosion and embrittlement and thus adequate exclusions should be in place. Even if considered in design, these risks are inherent to hydrogen operations and the question of sudden/unforeseen is per natura to be affirmed.

Firefighting standards: Given the increased risk of fire and explosion, adequate fire protection measures and safety standards need to be ensured. Appropriate clauses need to be implemented. Especially live testing and protocol of readiness prior to critical operations needs to be addressed.

Manufacturer's warranty: With reference to the dynamic H_2 technology development, it should be ensured that manufacturer's warranty as well as any form of availability guarantees should remain primary to the insurance. The same applies for warranty bonds in case of the insolvency of OEMs or EPC contractors.

The risk of assuming entrepreneurial risks is very high, both in property damage and business interruption.

Series loss clause: With modular technology (e.g. containerized electrolysers) and scaling up via parallelization serial loss exposure resulting from defects in design, plan, specification, material, and/or workmanship becomes highly relevant. Insurers may seek to limit their PD and BI exposure by application of increasing deductible per loss and/or by reducing the indemnity via serial loss provisions.

The Serial loss clause should be aligned with the defect language and with the definition of occurrence to avoid an unintended broadening in cover

Testing: As soon as hydrogen production equipment is started for testing purposes, H_2 projects are subject to explosion risks. It is therefore recommended to develop a clear definition of testing and limit the testing period accordingly for phased testing and commissioning.

Handover: With many H_2 projects coming in modular forms, the takeover procedure needs to be clearly defined (takeover of the entire project vs. individual items). Likewise, contractual provisions for initial operation (incl. PD and BI) need to be set out in the policy. In this context it is worth noting that initial operation can sensibly impact the PML scenario of the project.

Maintenance: Given the often unproven/prototypical nature of H_2 projects, maintenance cover has to be considered carefully and no maintenance coverage should be wider than defined elsewhere in the policy. Some hydrogen projects might be unproven/prototypical. In this case extended or guarantee maintenance may involve high risks. Therefore, each project must be carefully analyzed prior to binding.

Existing / Surrounding property: H_2 projects are often developed within or adjacent to exposed property and hazardous operations. Therefore, the risk of damage to and from existing property needs to be examined and limited.

Physical loss: Electrolysers, reactors, reformers are subject to condensation, corrosion, impurities, and recombination of gases all of which do not by themselves necessarily constitute physical loss or damage. In fact, a proper definition of the latter prevents insurers from assuming liability for pure clean-up costs. Likewise pure electrical breakdown without physical loss or damage should not be part of the policy trigger.

DSU / BI: given the variety of H_2 related business models as well as the potential risk of fluctuating commodity market prices. Additionally, long lead times must be considered for hydrogen generation equipment.

It is vital to structure the DSU/BI indemnity based on "actual loss sustained"

Accordingly, there should be no indemnity for the amount of any sum saved or received (e.g. through contractual penalties) as a result of delay/interruption nor covering additional costs due to market risks related to speculation or demand/supply interruptions.

Pre-fabrication: Significant pre-fabrication issues have been reported in the oil & gas as well as the renewables industry with welding, coating, and painting works being a specific area of concern. That said, adequate underwriting measures such as defects exclusion, loss limits and robust deductibles should be taken where pre-fabrication is included.

Hydrocarbon exclusion (where applicable): From the moment in which hydrocarbons and critical media are processed, Insurers may seek to enforce industry safety standards as precondition to any liability and to limit and/or exclude losses affecting specific items (e.g. catalyst).

Sections: Exposure for pipelines and open trenches should be limited by section clauses. The same applies for tunneling works.

Horizontal Directional Drilling (HDD): Downstream integration of H_2 projects may include complicated CAR/underground works incl. HDDs which carry high levels of risk. Adequate HDD exclusions are required to mitigate the exposure.

Tunnel boring machines (TBM): Careful assessment, adequate deductibles and insuring clauses are mandatory when TBMs are involved (e.g. in cavern storage) and the same applies for the Tunneling Code of Practice.

Cargo and transport risk: H_2 projects can involve both expensive equipment with long lead times (e.g. transformers, gas compressors) and items being shipped in large quantities (e.g. containerized electrolysers). Where cargo risks are included, it is recommended to evaluate this in more detail and to implement appropriate contractual measures such as a Marine 50/50 clause and relevant sub-limits.

Cyber exclusions: H_2 projects can be part of critical infrastructure and thus may be subject to cyber-attacks. It is therefore recommended to use market standard cyber exclusions.

Malicious damage and social risks: Malicious damage by employees, subcontractors, external partners and SRCC related events are much more critical regarding catastrophic exposure insuring hydrogen projects, compared to traditional engineering risks. Access control and emergency plans are mandatory, wording should consider and limit these risks elements. Needless to say, this applies for war and terrorism provisions.

Third party liability: From damage to 3rd party property and bodily injury (e.g. through explosion) to pollution and contamination (e.g. through alkaline electrolytes),

Hydrogen projects bear plenty of TPL risks which need careful assessment.

The TPL trigger needs to be clearly defined and pure financial losses (e.g. through contractual liability) should be avoided. Robust exclusions to TPL coverage (e.g. EIL) are required.

LEG Green hydrogen exclusion: Reference is made to the recently issued LEG exclusion clause, since the clause has been drafted for different upstream applications, Underwriters may consider additional exclusions (e.g. membranes), provisions (detection, firefighting, certification) and/or clauses (e.g. serial clause, depreciation) specific to the project.

Annex 3: Required underwriting information is a list of relevant underwriting information to allow adequate assessement of hydrogen projects.

Key takeaways:

- In the absence of trusted standards for certification, Underwriters have to assess projects case by case and rely on Engineering knowledge (especially OEM/ contractor experience).
- Obvious risks (fire, explosion, mechanical damage) remain relevant, while novel and less obvious risks (design, modularity, interdependencies) need careful consideration.
- Hydrogen projects are subject to significant internal and external PML risks and layout as well as integration of projects are key to adequately assess PMLs.
- Given the technological specifics of hydrogen due Underwriting process should be kept and best practices should be applied (e.g. design risk/ LEG clauses, series loss clauses etc.).

8. Hydrogen Risk Outlook

The hydrogen economy is still in its infancy. There is no doubt that it will grow substantially in the future. Some industry reports predict that the amount of hydrogen in the energy mix will be only 0.5% in 2030 and that the large-scale development of the hydrogen economy will therefore only take place in the 2030s[5]. On the other hand, it should be noted that most industry reports were written before the recent geopolitical tensions and the resulting disruption of global energy markets; technological breakthroughs may also accelerate scaling up. Ever since we have seen fundamental shifts in energy policy including a strong push towards energy independency. Industry analysts such as DNV are therefore predicting a 25% higher use of green hydrogen in Europe[42] and the recently passed US climate bill may be the single most important moment in the history of green hydrogen.

In any case, there will be plenty of pilot projects (often involving unproven/ prototypical technology or setups) coming to market as new players enter the industry. In fact, the hydrogen economy will most likely blur traditional industry boundaries and attract players from oil & gas and chemicals as well as the power and utilities industries. This shift will unleash private capital and comes in line with increased political efforts to foster the use of green hydrogen for decarbonization. Decreasing electricity costs for renewable energy and rising CO_2 costs of fossil fuels (and thus grey H_2) are likely to fuel the demand for green hydrogen. As a result, economies of scale will kick-in and together with technological evolution and smarter manufacturing will lead to decreasing levelized costs of hydrogen – LCOH[43].

The rapid technological evolution of electrolysers and other hydrogen technology will require a continued evaluation and a thorough application of best practices and lessons learnt. From a risk management perspective, the following aspects deserve special attention:

Industry standards and certification: It is likely that the hydrogen industry will follow the example of other developing industries such as renewable energy. As a result, there will be industry standards which will enable efficient and transparent certification of hydrogen technology and thereby help to reduce risks. This will include type certification of electrolysers and overall certification of projects to support bankability and insurability. The certification of entire projects (rather than individual components) is especially relevant for interface risk which currently lacks transparent and aligned standards.

Regulatory framework: The key driver of LCOH besides electrolyser CAPEX is the cost of electricity. Design optimization and scaling up will expectedly reduce the investment costs in the mid-term. With electricity grids adopting higher shares of renewable energy and a multitude of subsidy schemes being rolled out across different countries, there is often a regulatory gap concerning the hydrogen industry. It is likely that this gap is going to be closed and that efficient regulation will be introduced to create investment certainty, managing risk allocation, and allowing the hydrogen industry growth through sustainable business models. Some of this regulation is likely to span across countries (for instance when it comes to a European power grid). The introduction of regulatory frameworks will support risk allocation and management across the industry.

Original equipment manufacturer (OEM) market structure: Currently the hydrogen industry continues to see new entrants with leading degrees of experience, but as technology evolves and becomes more standardized there is likely going to be more concentration in the OEM space with a couple of vendors dominating the market for electrolysers and other key hydrogen equipment. Like wind or gas turbines, hydrogen technology will be part of an iterative cycle of upgrades, certification, and maturity. Ultimately this will drive market wide definitions of prototype as well as proven status of equipment and increase overall trust in technology.

Formation of industry bodies: Aiming to balance economic growth, technology evolution and risk management, trusted industry bodies will emerge in the hydrogen economy. The constant exchange of industry experts and other stakeholders is likely going to facilitate overall risk management efforts and thereby improve risk quality in the industry.

Continued hydrogen integration: As the industry develops there is more and more integration of hydrogen in industrial processes. Together with the creation of new business models, this will raise questions of risk allocation and responsibilities. Ultimately this could lead to broader forms of risk management solutions such as cross-LoB policies. Also, specific open cover or turnover solutions for OEMs and project developers are likely to emerge.

Key takeaways:

- The outlook of the hydrogen economy continues to bear several known and emerging risks, with a high level of interdependencies between risk factors.
- Newly developing business models and standards, inexperienced market participants as well as prototypical/unproven technology require thorough analysis and constant monitoring.
- It is therefore recommended that industry participants (such as OEMs, contractors, operators) join forces with investors, insurers, and trusted certification bodies to improve risk management and enable best practices as well as lessons learnt in the hydrogen industry.
- Ultimately, industry bodies, expert committees and joint industry projects will be key to enable a safe and sustainable hydrogen future and secure the bankability and insurability of hydrogen projects.

9. Coverage, Claims

This section discusses some known industrial hydrogen incidents from the last 5 years but also considers hypothetical claim scenarios that may arise in future. The hypothetical claim scenarios focus predominantly on the electrolyser.

Given that some of the claims and coverage scenarios can only be speculated upon at this stage, the intention is to provide the key areas for underwriters to consider as new industrial hydrogen risks are presented to them. It is not intended to provide a complete overview of every type of claim scenario that might arise. Whether bespoke hydrogen wordings are produced will also have a bearing on the future handling of claims. On existing hydrogen technologies (for example: pipelines, storage, transport, handling, production from natural gas, and existing electrolysis) the authors have researched existing hydrogen claims databases. Dominant root causes (such that they have been identified) for different industries and statistics are also be presented.

Exemplary claims

Electrolyser runoff leading to explosion

Our first scenario occurred in 2019. It relates to an explosion at an experimental fuel-cell power system in the South Korean city of Gangneung during a test operation. Three tanks of 40 m^3 capacity each were all destroyed in an explosion which sent debris across an area of well over 3,000 m^2. The preliminary investigation indicated that the tanks exploded as a result of a static spark when oxygen concentration exceeded 6% in one of the buffer tanks. The investigation also identified several construction and workmanship issues, from which there are important lessons to be learnt:

- The oxygen removing component was omitted during system implementation. Although the designer included oxygen remover in the initial design.
- The static spark remover in the buffer tank was also omitted during construction. It should have been connected to earth but was not. This was because the contractor identified a concrete foundation underneath the tank's proposed location, which could have been damaged or difficult to reestablish.
- The operator ran the water electrolysis system below the as-designed power level, which induced the increase of oxygen concentration. The system had an asbestos separation membrane that had to be operated at a minimum of 98 kWh. However, the system obtained its power from solar power. Due to the inconsistencies associated with solar panel power production, the system often operated at a level below the necessary 98 kWh. It is believed that the power inconsistency caused the electrolyser membrane to degrade.
- The oxygen concentration was allegedly detected to be higher than 3% prior to the incident. This should have prompted the operator to install an oxygen remover. However, the operator apparently ignored this issue and continued the operation to reach the 1000 hours of required experiment validation time.
- Finally, the safety management team did not follow safety regulations that required it to monitor hydrogen quality daily[44,45].

The deteriorating "Membrane" in this scenario led to a H_2–O_2 explosive mix, which quite clearly caused damage to other components of the facility. Claims may therefore be presented to underwriters in future that involve consequential damage to insured and/or neighboring property. There are two key take-aways from this claim scenario:

- The importance of proper process monitoring. For example, if membrane issues had been discovered earlier or if the contractor had properly followed the design, the explosion would not have happened or could have been prevented. How the policy would respond in these circumstances depends on the combination of what obligations are placed on an operator by underwriters to review installation procedures and what requirements are on the insured to conduct adequate maintenance and rectification. Once damage does occur, the consideration of faulty part wordings and / or LEG clauses for prototype technology will be significant, particularly when there are likely to be consequential losses to unrelated components.

- This scenario also highlights one of the key risks associated with the production of "green" hydrogen. Renewable energy sources are often intermittent (for example: windfarms can only produce power when the wind is blowing, and solar panels can only produce power when the light conditions allow) and this creates difficulties for elements that require consistent power to function correctly. How designers and operators seek to overcome these intermittent power issues with the electrolyser in truly "green" industrial hydrogen projects will be a matter for underwriters to keep under close review.

Failure in detection system leads to explosion

As discussed earlier in this report, suitable hydrogen gas detection is key. A failure to detect hydrogen leakage creates a clear explosion risk. For example, in the AB Speciality Silicones explosion in the USA in 2019, a failure to detect a hydrogen leak at a silicone plant was directly attributable to the explosion that subsequently occurred. The US regulator found:

"The building was not equipped with functioning detectors for hydrogen or other flammable gases. While the building filled with flammable vapours, the workers attempted to open the emulsion area to outside air and turn on fans. They were unable to complete these efforts before the building exploded"

From a claim perspective, it is quite clear that leakage detection measures will be scrutinised when losses caused by leaks are presented. Although we consider that for most industrial hydrogen projects leakage detection should be manageable, the quality of leakage detection should form a key part of underwriters' risk analysis. However, in this context it is important for underwriters to consider the law and jurisdiction of the policy they are proposing to write. For example, in some jurisdictions a failure to request specific information from an insured in a proposal form might mean that insurers remain on risk notwithstanding a failure on the part of the insured to disclose that it did not have hydrogen detection mechanisms in place. Underwriters should seek appropriate advice in the jurisdiction they are seeking to make the policy subject to and should not assume that the same proposal forms or policy wordings will have the same effect in all jurisdictions.

Hypothetical claim scenarios

Serial losses – Electrolyser stacks

Electrolyser manufacturers are seeking to increase electrolyser output. For example, it is not uncommon for 10-20MW projects to announce that 100MW output of hydrogen is the eventual goal (reference is made to reference projects in this magnitude Refhyne in Germany and Gigastack in the UK]) and projects above 1 GW are today in the development phase. Indeed, an increase in output with PEM electrolysers, is usually associated with an increase in the number of modules in an electrolyser "stack". For example, for a 10MW PEM electrolyser, it is common to see 5 x 2MW modules which together form the 10MW "stack" output. From a claim perspective, the following considerations are relevant:

- It remains to be seen whether the continued development of PEM electrolysers will see increased module capacity as an alternative to an increase in stack size. However, if module capacity is increased as an industry standard then how quickly will existing modules become obsolete? In a claim scenario where obsolete modules are damaged, repair and / or replacement costs for obsolete items are likely to be key adjustment considerations.
- Some industry experts have suggested that high-temperature membrane electrolysers will prove to be more efficient and more powerful than PEM membrane electrolysers. If that is the case and if PEM as a technology becomes obsolete, then the same issues will apply.
- As more electrolysers come to market, the extent to which modules are compatible with each other will also be significant. For example, if only one manufacturer is able to supply a particular

replacement module, then supply times and availability could have ramifications under various claims scenarios, particularly those involving significant Business Interruption exposures.

- Linked to supplier availability is supplier viability. In circumstances where a sole manufacturer produces specific modules per electrolyser stack, the unavailability of replacements as a result of supplier insolvency, or a lack of availability (say due to excessive lead-times) could have a significant impact on the total costs that could be incurred. Additionally, the extent to which an Insured is able to claim for a repair or a replacement under a warranty is also significant and Insurers may want to consider up front where the risk of supplier insolvency should lie.
- It will also be important for underwriters to assess which components within modules are realistically replaceable. For example, depending on the issue, a claim concerning damage to a membrane might require the replacement of an entire module, or even the replacement of an entire stack. It is for this reason that Insurers should keep abreast of developments of electrolyser technology.
- A related point is that if it is assumed that membranes in industrial-scale electrolysers will be replaceable after they reach the end of their service lives (which is currently estimated to be around 2 years after the commencement of production) then that is likely to require underwriters to consider whether a reducing basis of indemnity should be included for those membranes. This is particularly significant given that approximately 45% of project CAPEX for industrial hydrogen project cost relates to the electrolyser.
- Finally, we note above that PEM electrolysers work by "stacking" modules. Therefore, a design type issue in one module may be replicated in other modules. As the number of modules increase, so does the risk of serial issues become ever more costly to underwriters. In these circumstances, underwriters may wish to include a series loss clause into their hydrogen wordings. This has the effect of covering the same defect on a sliding scale, usually starting at 100% for the first [x] number of losses and then decreasing for the next [x] number of losses until a set value of series losses has occurred after which no cover is provided. The key issues for underwriters to consider are what types of incidents or defects would underwriters propose the series loss clause to be applicable to and, depending on the scale of the project, how many of the same type of losses would underwriters propose to cover before the scale decreases or expires entirely.

NatCat: EQ, lightning, storm, wildfires, flood

Where, as noted above, something as seemingly inconsequential as a static spark might cause an explosion at a hydrogen facility, it is not difficult to foresee that most NatCat scenarios may lead to catastrophic explosion events, potentially affecting not only the insured property but also neighboring infrastructure. Business Interruption could also be significant. As a result, explosion prevention and then explosion protection are likely to be relevant considerations for insureds as well as for underwriters. Design considerations as well as applied standards will be in focus and policy wordings relating to faulty design will be key in regards of coverage.

Consideration of blast dynamics

Explosion prevention is another significant consideration for insureds that operate with hydrogen. However, the blast dynamics of hydrogen in commercial use are not yet fully understood. Insurers may face liability claims as a result of hydrogen explosions, the question of what damage was caused by a hydrogen explosion as opposed to, say pre-existing damage or some other cause, may require some refinement. Accordingly, Underwriters must ensure that their knowledge of hydrogen blast dynamics, design standards and its interaction with NatCat scenarios is up to date.

Flood scenarios can cause serious damage to facilities even if not catastrophic, even if most electrolysers are pressurized and this may offer inherent protection for module internals, damage to electrical equipment, cost of clean-up and restarting operations should not be underestimated. BI and CBI damage can then be significant.

Control system failure

As with any industrial facility, the maintenance of adequate control systems will be fundamental to the risk profile. For a hydrogen facility it is likely that operators will have numerous units integrated into a single facility. Should a control system fail at a hydrogen facility, the authors consider unlikely that the cost of repair to that system will drive the costs of any claim. Instead, Business Interruption is likely to provide the greatest exposure, not least because current electrolyser designs are so sensitive to their environments (be that temperature, power supply or even water quality). Accordingly, even with a shut-down as a result of a control system failure, the knock-on effect to the electrolyser and other critical equipment is likely to create knock-on issues to the facility that may, at first be unforeseen. How underwriters settle an initial control system failure claim will therefore be significant for potential future claims at the same facility. The same can be said even if control system warranties are easily enforceable.

Depending on agreed wordings, liability for business interruption could be based on contractual schemes, e.g. availability guarantees, volatility of prices for replacing product and other variables which were not assessable and may represent entrepreneurial risk elements, thus Underwriters need to stick to “actual loss sustained” and a clear basis of indemnity.

Quality of energy supply

The quality and / or reliability of energy supply is critical for a PEM electrolyser, but it is also critical for all electrolyser types. Issues with the energy supply include voltage peaks, voltage drops, drops in supply or no supply. Any of these issues could cause production problems for electrolysers and even, possibly, electrical damage. Equally, energy supply issues can also affect other electrical distribution systems. Transformer design and electrical protection logic should consider and mitigate many issues, and UPS systems should be able to ensure safe shutdown. But at this stage of scaling up facilities and optimizing processes, no system can be considered as fail-safe, disregard of the human factor.

How this energy supply issue can be managed by an operator will differ from project to project, however green hydrogen (i.e., hydrogen produced from solely renewable sources) is likely to face unique challenges. For example, for a hydrogen plant connected to a windfarm, how will a consistent energy supply be maintained when the wind is not blowing? At present there appears to be two alternatives: (i) the use of battery power to store energy produced in abundant periods; and (ii) the connection of the facility to the grid. The problem with (i) is that battery storage on a large scale presents its own risks (particularly at sites with significant fire and explosion risks in any event); and (ii) connecting a “green” facility to the grid may call into question the extent to which the facility can truly be regarded as “green” (thus undermining the very purpose of the project in the first place).

It is also the case that, with varying energy supply, Contingent Business Interruption might be affected depending on the extent of the coverage provided and the interdependency of projects. In this context it is already notable that some green hydrogen projects will produce hydrogen for a single local customer.

Premature membrane deterioration

The deterioration or failure of components over time call into question issues such as gradual deterioration (which may be excluded in a policy wording) and might also call into question whether electrolyser membranes themselves can be considered a “part” in possible faulty or defective part wordings.

An additional issue here is that with membrane degradation being linked to the operational regime in most systems, if an insured fails to accommodate known power fluctuations and/or needs to contractually respond to extreme or untested operational cycles, this may bring due diligence considerations to the fore. Due diligence may also be a consideration in circumstances where warnings in relation to deterioration may have been missed or ignored.

Other considerations

- Requirements for service and maintenance intervals (for example, (equivalent) operational hours of membrane and water quality and/or operational parameters as a trigger for preventive maintenance) could provide significant protections for underwriters and an analysis of these requirements will need to be conducted carefully at the claims stage.
- Underwriters should consider where the risks of warranty viability should lie. In addition to that is the issue of the interconnectivity of warranties. For example, whether warranties are provided for a single turnkey project and if not whether there the inter-dependence of warranties are suitable in long term installation projects. It is also important to assess the expiry of warranties and whether underwriters are, in effect, being asked to provide guarantee maintenance. This issue may well differ from project to project, but upon the presentation of a claim the viability of existing warranties and the obligations on the insured to comply with warranty claim requirements will need to be explored.
- Some hydrogen projects are considering placing electrolysers offshore. Under offshore conditions, electrolysers are likely to face much harsher and more corrosive environments. They are also likely to be more difficult (and more costly) to inspect, maintain and repair. We suggest that underwriters consider their pricing carefully when considering risks associated with offshore hydrogen assets.
- As noted elsewhere in this report, the risk of metal embrittlement of from hydrogen is significant. One factor that will be key is the potential effect of embrittlement on existing structures, for example: in existing pipelines and storage tanks. Understanding the process of embrittlement (not just for existing property that has been converted for hydrogen use) and when the embrittlement process can be said to cause damage is going to be a key consideration for claims handlers working on hydrogen claims. This is an issue that is also likely to differ from jurisdiction to jurisdiction.
- As to general claim exposure, green hydrogen projects linked to offshore wind farms are likely to be dominated by logistics costs (including vessel spreads). A typical offshore wind claim is usually split as follows: two thirds logistics costs and one third costs for parts and repair. Equally, claims for the offshore transport of hydrogen should be comparable to claims in other energy classes (for example, natural gas), with offshore explosion risks being broadly similar, although smaller quantities of hydrogen are expected initially.
- At a practical level, given that industrial hydrogen projects are going to expand significantly in the coming years, ensuring that there is adequate expertise available from service providers (particularly loss adjusters and experts) will be critical. A feature of some hydrogen incidents is the difficulty in underlying cause detection. For example, at a hydrogen fuel plant explosion in North Carolina, USA, in April 2020, it has been publicly reported that the cause of the explosion may never be known. This is of course of some concern for insureds that use hydrogen at their facilities, however it is also of concern for underwriters given the importance of cause analysis to claims handling. It is anticipated that cause investigation technology will improve as hydrogen claims become common, however it is also likely to be the case that claims handlers may need to consider specialist experts who operate outside of their usual networks. Other causes of claims identified in the claims databases are:
- Disconnected alarms
- Incorrect opening of valves
- Pipe breaks (embrittlement, corrosion)
- Wrong handling / human error

Transport and handling of Hydrogen (Pipeline, Truck, cylinders, pumps, valves): Several incidents are well documented. Prominent root causes include:

- Valves e.g., failures in handling / design / installation
- Leaking pump
- External perils e.g. collision during transport
- Embrittlement
- Failure in detection

- Lack of safety / HSE rules / Human error

Claims in Gas turbines: Pure Hydrogen as energy source: no incidents found. Natural gas turbines few incidents on false manual handling of hydrogen as a coolant (generator) which leads to explosion were reported.

Most registered incidents could have been avoided by following basic safety principles. The human factor, meaning organizational safety principles seems to be the key element (SP 9 + SP 10) out of the historical claims experience.

Key takeaways:

- Whilst there are numerous hydrogen specific claims issues, the most critical risk element remains the human factor

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Annex 1: Regulations, standards, and codes

While codes and standards provide the roadmap and framework for construction, as well as guidelines for operation, a site or fleet specific procedure for operation and maintenance of the facility needs to be developed in an effort to safely operate and maintain the plant.

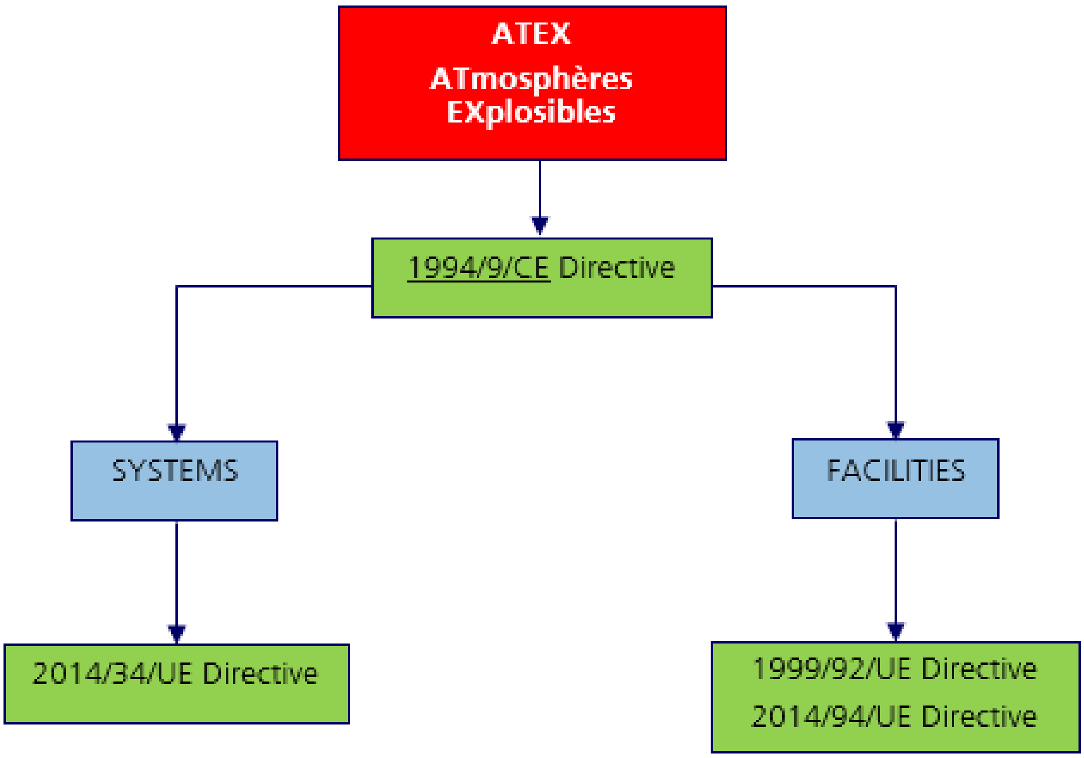
Most of the relevant safety aspects are regulated by EU directives and through statutory regulations, standards, and codes.

EC Directives

European laws, such as Directives or Regulations, prevail over national laws. In order to carry out their task and in accordance with the provisions of the Treaty establishing the European Community (the EC Treaty), the Parliament acting jointly with the Council, the Council and the Commission make regulations and issue directives according to Art. 249 of the EC Treaty.

A directive shall be binding, as to the result to be achieved, upon each Member State to which it is addressed, but shall leave to the national authorities the choice of form and methods (national transcription).

Requirements for products and operational requirements are strictly separated in EU legislation since they belong to different political objectives and are governed by different articles of the EU treaty[1].



Guidelines to application of the Directive 2014/34/EU:

https://ec.europa.eu/docsroom/documents/41403/attachments/1/translations/en/renditions/native

ATEX directive 99/92/EC relates to minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres (ATEX).

Hydrogen is a flammable gas which can form an ATEX where mixed with air (such an ATEX is defined by the directive as a mixture in which, after ignition occurred, combustion spreads to the entire unburned mixture). Hazardous zones are defined as follows:

• Zone 0: a place in which an ATEX is present continuously or for long periods or frequently.

• Zone 1: a place in which an ATEX is likely to occur in normal operation occasionally.

• Zone 2: a place in which an ATEX is not likely to occur in normal operation but, if it does occur, will persist for a short period only.

ATEX directive 2014/34/EU applies to equipment and protective systems intended for use in potentially explosive atmospheres. It also applies to controlling devices and regulating devices intended for use outside potentially explosive atmospheres but required for or contributing to the safe functioning of equipment and protective systems with respect to the risks of explosion are also covered by the scope of this directive.

Both directives are interrelated. Equipment from certain categories according to 2014/34/EU can be used in certain zones defined according to 99/92/EC, but is forbidden in others.

The PED (Pressure Equipment Directive – 97/23/EC of the European Parliament and of the Council of 29 May 1997 on the approximation of the laws of the member States concerning pressure equipment) is applicable in Europe since December 1999 and mandatory since end of May 2002. It applies to all stationary vessels with service pressure of more than 0.5 bar and a volume of more than 50 liters.

Since this directive is mandatory in Europe, a number of “Notified Bodies” have been notified to Brussels by the authorities of each EU members states. These notified bodies can make the “evaluation of conformity” of the pressure equipment; this evaluation is confirmed by the “CE” mark applied onto the equipment. Any notified body (from every country) can approve a CE marked equipment to be used in every country of the EU.

This directive only defines the “essential requirements”. Detailed requirements are given in the harmonized standards (e.g. prepared by CEN). These EN-Standards are not mandatory, other procedures or “state of the art” can be used by the manufacture in order to demonstrate to the notified body that the essential requirements are fulfilled.

This European directive doesn’t cover the use of the equipment (operational requirement, periodic inspection, …) which are still under national regulations. This may create difficulties if such equipment is to be moved from one country to another.

The most important committee in Europe is CEN/CENELEC TC 6 “Hydrogen in Energy Systems”. It has not yet published standards of its own. The committee cooperates closely with ISO TC 197.

Hydrogen relevant standards are not made only by one or a few committees, however. Since hydrogen energy has relationships to many other fields, standards for pressure vessels, pipelines, gas quality etc. must be taken into consideration as well[1].

Standards and codes

These are not legal requirements. However, they serve as guidelines for design and safe operation.

The directives offer the possibility of meeting safety requirements by designing and manufacturing the products of compliance with the essential health and safety requirements, through the harmonized standards that have been developed specifically by relevant government agencies, to allow a presumption of conformity with such requirements.

European National Standards

European Standard (EN) are developed by a recognized European Standards Organization such as CEN, CENELEC, or ETSI. These European Standards have been developed by the Technical Committee and adopted in the EU states as identical national standards:

- UNE: Spanish national Standard
- DIN: German national Standard
- BS: British national Standard
- NF/AFNOR: French national Standard
- UNI: Italian national Standard

The "European Standards" (EN), which were established by the CENELEC countries, are valid as national standards in all affiliated countries. The European Standards (EN) are identical in all countries with regard to their content. They are published as national standards as follows:

Country	Requirements General	Box Explosion-proof "d"	Safety increased "e	Security intrinsic "i"
International (CENELEC)	EN 50 014	EN 50 018	EN 50 019	EN 50 020
Belgium	NBN C23-001	NBN C23-103	NBN C23-102	NBN C23-101
Denmark	AFSNIT 50	AFSNIT 50-4	AFSNIT 50-4	AFSNIT 50-6
Germany	DIN EN 50 014 VDE 0170/0171 T.1	DIN EN 50 018 VDE 0170/0171 T.5	DIN EN 50 019 VDE 0170/0171 T.6	DIN EN 50 020 VDE 0170/0171 T.7
Finland	SFS 4094	SFS 4098	SFS 4099	SFS 4100
France	NF C23-514	NF C23-518	NF C23-519	NF C23-520
Britain	BS 5001: Parte 1	BS 5501: Parte 5	BS 5501: Parte 6	BS 5501: Parte 7
Italy	CEI 31-8	CEI 31-1	CEI 31-7	CEI 31-9
Netherlands	NEN-EN 50014	NEN-EN 500 018	NEN-EN 500 019	NEN-EN 500 020
Norway	NEN 110	NEN 114	NEN 115	NEN 116
Austria	EN 50 014	EN 50 018	EN 50 019	EN 50 020
Sweden	SS EN 50 014	SS EN 50 018	SS EN 50 019	SS EN 50 020
Switzerland	SEV 1068-EN 50 014	SEV 1072-EN 50 018	SEV 1073-EN 50 019	SEV 1074-EN 50 020
Spain	UNE 21 814	UNE 21 818	UNE 21 819	UNE 21 820

International Standards

ISO: International Organization for Standardization (ISO TC197 Hydrogen technologies)

IEEE: Institute of Electrical and Electronics Engineers

IEC: World standardization organization for electrical, electronic, and related technologies) is responsible for international standardization in the field of electrical technology.

The IEC has introduced a procedure – so called IEC-Ex Scheme – intended to become a globally recognized test and certification procedure in the field of explosion protected electrical apparatus. Hydrogen systems should be classified according to the IEC 60079-10-1 standard. It is very important to follow said standard to prepare the classification of areas and define the danger of the different areas of the installation based on acquired classification.

IEC Standards	EN	Description
IEC 60079-0	EN 50 014	General requirements
IEC 60079-1	EN 50 018	Construction and testing of explosion-proof boxes for electrical appliances
IEC 60079-1A	----------	Test method for determining the maximum experimental security gap
IEC 60079-2	EN 50 016	Electrical appliances – type of protection „p"
IEC 60079-3	EN 50 020	Spark Test Apparatus for Intrinsically Safe Circuits
IEC 60079-4	-----------	Test method for ignition temperature -4A
IEC 60079-5	EN 50 017	Sand Filled Apparatus
IEC 60079-6	EN 50 015	Oil immersed apparatus
IEC 60079-7	EN 50 019	Construction and testing of electrical apparatus, type of protection „e"
IEC 60079-10	EN 60079-10	Classification of high-risk areas
IEC 60079-11	EN 50 020	Construction and testing of intrinsically safe apparatus and other related equipment
IEC 60079-12	EN 50 014	Classification of gas or vapor mixtures with air according to their maximum experimental safety gap and minimum ignition currents
IEC 60079-13	---------	Construction and use of rooms or buildings protected by pressurization
IEC 60079-14	EN 60079-14	Electrical installation in explosive gas atmospheres (other than mines)
IEC 60079-15	pr EN 50 021	
IEC/TR 60079-16	----------	
IEC 60079-17	EN 60079-17	
IEC 60079-18	EN 50 028	
IEC 60079-19	prEN 60079-19	
IEC/TR 60079-20	----------	
IEC 60079-29		Gaseous hydrogen detectors are, many times, a safety requirement and must comply with the IEC 60079-29-1 standard

Regulatory regime around hydrogen supply chain:

H2 GENERATION

- ISO TC197 Working Group 9 (ISO 16110-2) Hydrogen Generators Using Fuel Processing Technologies
- ISO 22734:2019 - Hydrogen generators using water electrolysis — Industrial, commercial, and residential applications
- ISO 16110-1:2015 Hydrogen generators using fuel processing technologies
- ISO/TC 197 Hydrogen technologies
- ISO/TC 158 - Analysis of Gas
- AIAA G-095 - Guide to Safety of Hydrogen and Hydrogen Systems
- ISO TR 15916 Basic Considerations for the Safety of Hydrogen Systems
- IEC/TC 31 - Equipment for explosive atmospheres

STORAGE/TRANSPORT/ DISTRIBUTION

- CE 1272/2008 - Storage at the production site for later distribution.
- NFPA 55 Storage, Use and Handling of Compressed Gases and Cryogenic Fluids in Portable and Stationary Containers, Cylinders and Tanks

Land Transport:

- CEN/TC 268 - Storage and transport of liquid hydrogen
- CEN/TC 23 - Storage and transport of compressed hydrogen

Pipeline:

- CEN/TC 234 - The injection of hydrogen and the mixture of hydrogen with natural gas (H2NG) in the gas infrastructure

Maritime Transport:
IMO IMDG Code
IMO IGC Code

REFUELING / TRANSFER

- IEC 60079-29-2 Explosive atmospheres – Gas detectors - Selection, installation, use and maintenance of detectors for flammable gases and oxygen
- ISO/TS 20100:2008 - Gaseous hydrogen — Fuelling stations
- ISO 17268:2020 - Gaseous hydrogen land vehicle refueling connection device
- EN 17124:2018 - Hydrogen fuel - Product specification and quality assurance
- EN 17127:2020 – Outdoor hydrogen refueling points dispensing gaseous hydrogen and incorporating filling protocols
- CEN/TC 305 - Potentially explosive atmospheres - Explosion prevention and protection

COMERCIAL USE

- CEN/TC 268/WG 5 Specific applications of hydrogen technologies
- IEC TC 69 - electric vehicles
- IEC TC 35 - fuel cells
- ISO TC 58 - compressed gas cylinders
- ISO 14687-2 Hydrogen Fuel - PEM fuel cell applications for road vehicles
- CLC/SR 105 - Fuel cell technologies
- EN 62282-3-100:2012 - Part 3-100: Systems stationary fuel cells. Security. IEC 62282-3-100:2012
- EN 62282-3-300:2012 - Part 3-300: Systems stationary fuel cells. Installation. IEC62282-3-100:2012
- EN 62282-3-100:2012. - Part 5-1: Battery Systems portable fuel.

Design Codes

Codes are developed by interested industrial parties. Some relevant codes and organizations are listed below for reference:

- EIGA: IGC Docs (Hydrogen stations, Pipelines)
- SAE International: J2601 (Fueling protocols)
- EHA European Hydrogen and fuel cell Association
- FCH-JU Fuel Cells and Hydrogen Joint Undertaking
- Hydrogen Europe
- HySafe International Association for Hydrogen Safety http://www.hysafe.org/
- HyER Hydrogen Fuel Cells and Electro mobility in European Regions
- H2ME Hydrogen Mobility Europe
- IEA International Energy Agency
- IPHE International Platform for Hydrogen and fuel cells in the Economy
- SHHP Scandinavian Hydrogen Highway Partnership
- The New European Research Grouping on Fuel Cells and Hydrogen – N.ERGHY

At the time of release of this publication ISO has been developing / updating hydrogen related norms, an overview can be found here:

Published: ISO - ISO/TC 197 - Hydrogen technologies

In development: ISO - ISO/TC 197 - Hydrogen technologies

Certifications

Some hydrogen technologies are fairly new and not standardized, certification and joint industry projects can help improve the reliability of technology and establish trusted electrolyser models and OEMs. Some recognized certification entities are DNVGL and TüV, which have developed industry standards teaming up with OEMs and established certification schemes.

References

[1] Safety planning for hydrogen and fuel cell projects. Fuel cells and hydrogen 2 joint undertaking (FCH 2 JU). July 2019

Annex 2: Summary of best practices and risk mitigation for hydrogen facilities

Below a summary of best practices and risk elements to be considered for hydrogen facilities, while the table is not exhaustive it may help identify and address known safety issues during design, operation, and maintenance.

Facility Design and Construction	
Element	Description
Design codes	- Define and implement state-of-the-art design codes - Tunneling code - Introduce unique equipment indentifier system from design phase
Ensure system integrity	- Leak tightness design and test - Avoid screwed connections - Ensure and test proper seal design for valves
Prototype	- Throughout validation of prototypes and scaled up components - Consider changes in operational modes (on/off vs.permanent) - Consider increment of units per stack for safety design - Consider changes in the control systems while scaling up - Combination of two known components is "new" philosophy
Lifetime of components	- Consider lifetime of components and define operating and maintenance cycles - Consider aging vs. Operating regime, including impact of changes in regime (EOH philosophy) - Define and monitor lifetime of critical components (HGP in turbines, membranes in electrolysers, materials exposed to embrittlement, corrosion, erosion) - Monitor parameters defining aging and integrate into EOH logic
Catalyst poisoning, regenaration	- Reformer catalysts are very sensitive to sulphur. Sulphur content can vary a lot between different natural gas streams, and it is important to have control of the desulphurization system in a SMR plant (hydrogenation reactor and zink oxide reactors). - In the hydrogenation reactor sulphur is converted to H2S and in the zink oxide reactors the H2S is absorbed. Normally there is teo reactors in series and any sulphur breakthrough would be between the two reactors. It is important to continually track the sulphur content at this point. - Steam reformer catalyst are normally activated with hydrogen/natural gas when fresh during initial startup. If this is not done in a proper way there is a risk that the catalyst do not work properly. This is especially important for SMR:s operating on naphtha instead of natural gas. - Operating steam reformers with the wrong steam/carbon ratio (steam/natural gas ratio) can damage the reformer catalyst (coke formation) giving an increased pressure drop with over heating of the reformer tubes as consequence. Over heating of the tubes can lead to tube rupture.
Vibrations and pulsations	- Consider vibrations and pulsations in design - Validate during commissioning and maintenance - Define and implement monitoring systems - Define and implement logic for alarm/trip
Operating limits	- Define and monitor operating limits (temperature, pressure, flow, concentration) - Define and implement in the systems logic alarm/trip thresholds - Check of transient operations during commissioning - Qualitative evaluation of safety effects resulting from failure of controls
Safety distance	- Consider enough distance between units for maintenance operations (e.g. between electrolyser to perform maintenance while other modules are operating)
Feed quality	- Define and monitor feed quality (e.g. water quality for electrolysers, fuel and air quality for turbines)
Safety design	- Preferred Fail-safe features and components - Best practice: Double block and bleed safety design - Interlock systems where applicable and according applying design standards - Relief and safety valves - Define and audit construction materials and procedures - Define and audit electrical classification, certification of electrical equipment - Pressure relief design and considerations - Ventilation systems design - Soild foundation design to avoid pipe and/or equipment rupture - State of the art flare design

Materials	- Consider corrosion and erosion (process flow, sea air, corrosive media) - Consider embrittlement and define lifetime, inspection and control plans - Consider thermal stability - Consider pressure resistance acc. standard including transient operations - Consider thermal expansion - Consider rupture limits, overheating of tubes and apparatus - Consider galvanic interaction - Consider aging - Consider creep behavior - Consider changes in operating parameters, transient operations and related impact - Validation of materials compatibility
NatCat	- Prevention and emergency plans in windstorm areas - Consider wildfires and floods and emergency plans - Earthquake design according state-of the-art standards for buildings, equipment and piping - Seismic response procedure, inspection and restart procedures following seismic events - Preferred vertical AND horizontal force compensators - Acceleration sensors and integration into logic (alarm/trip) - Consider and avoid freezing of safety valves and actuators
Audit	- External design audits (e.g. TüV) - Internal reviews during design, construction and operations - PHA, HAZOP Study
Fire Protection	
Element	Description
Limit hydrogen inventories	- Preferred outdoor storage - Reduce size of storage units - Preferred on-demand onsite production - Define and audit maximum allowed storage of hazardous materials
Limit leak volume	- Preferred small pipe diameters, flow restrictors when possible - Design of excess flow valves and discharge nozzles
Ventilation	- Preferred natural ventilation - Use mechanical ventilation system or inerting system if natural ventilation not enough - Ventilation design and operatibility for indoor storage - Ventilation management in process logic and emergency procedures - Avoid confinement, avoid protective roofs etc., where hydrogen might accumulate - Increase distances - Use passive ventilation, explosion vents - Continuous control of mechanical ventilation, avoid cost saving measures
Suppression systems	- Use catalytic recombiners where relevant (for large release rates recombiners might be not suitable, in high hydrogen concentrations a recombiner could be an ignition source) - Use flame or detonation arrestors, periodic control - Define and audit firefighting systems, inert gas suppression (CO2/N2), isolation
ATEX Zones	- Definition and control of ATEX Zones - ATEX Materials and certified equipment - Avoid ignition sources in ATEX sources,both in design and operational procedures - Proper grounding and control - Avoid congestion, reduce turbulence promoting flow obstacles (volumetric blockage ratio) in the respective ATEX zone - Publish map of ATEX zones, safety marking
Leak detection	- Use of LEL Detection systems and dedicated analysis of required locations - Process monitoring considering leak detection, alarms and trip logic - Emergency shutdown of equipment where required - Emergency shutoff of valves and restrictors - Emergency signals and measures - Shutdown of electrical equipment - Define other countermeasures and document accordingly
Lightning protection	- Proper lightning protection, periodic tests
Inertization	- Inertization is done before startup and shutdown of all system that will contain flammable gas. This should be done with an inert gas like nitrogen. Before startup, after for example a maintenance shutdown, the system needs to be free from oxygen and purged to the atmosphere (not to the flare system since it can contain oxygen). The system is normally purged until the oxygen level is at least below 0,5% vol. This can be done by pressurizing to 5 bars and realizing it down to 0,5 bar. This is done repeatedly until the oxygen level is low enough. - After shutdown the system is inertized in the same way but the gas is released to the flare system (if there is one). Otherwise vented on at high elevation not exposing surrounding systems or persons. - Before any assemble LEL-measurements should be done to verify that the system is free from flammable gas. Any human entry into the systems require additional measures. - It is important to include all systems that will be exposed to flammable gas including dead ends and pipe lines
Flame visibility	- Consider visibility of hydrogen flames - Thermal imaging, linear heat detection
Combustible control	- Control combustible elements during maintenance shutdown

Human factor	
Element	Description
Startup/Shutdown procedures	- Clear startup and shutdown instructions in local languages with step by step instructions preferable connected to valve tag numbers, pumps numbers etc. - The instruction should be a part of the operator training and referring also to P&IDs and PFDs - Startup and shutdown instructions should be available in paper form in the control room
Emergency procedures	- Emergency instructions should cover events like fire event, power failure, loss of cooling water, loss of instrument air, etc. - The instruction should be based on PHA and risk analysis connected to the different events - Emergency instructions should be available in paper form in the control room, in local language
Safety plan	- Provide site specific annual and multi-annual safety plan - Define and monitor significant hazards and hazardous operations - Distribute within staff and integrate into safety training prior to site access - Organize periodic safety reviews - Mitigation planning - Emergency planning and management - Define safety champions and responsibilities - Review proposed changes to materials, technology, equipment, procedures and staff
Preventive Maintenance	- Define and implement preventive maintenance plan - Periodic calibration of safety related systems and instruments - Hose and pipes exchange requirements
Corrective Maintenance	- Continuos monitoring of leaks and malfunctioning - Correct deficiencies outside acceptable limits
Testing and inspection	- Perform periodic testing of components and safety systems - Dedicated testing and documentation of detection systems, calibration - Proper documentation of inspection and results
Training	- Initial training including process overview, operating procedures, safety and health hazards, work permits, ATEX zones, emergency operations, etc. - Access control to construction site subject to hydrogen specific training (incl. ATEX zones and emergency procedures) - Organize and control participation in hydrogen-specific safety courses for operational and maintenance personnel - Perform refresher courses on periodic basis
Audits	- Perform periodic internal and external audits - Develop self-audits and related templates, checklists - Develop and monitor pre-startup safety reviews - Develop and implement whistleblower policy for safety issues - Perform periodic simulated emergency operations
Reporting	- Report near misses, incidents and accidents - Introduce and follow up implementation of lessons learnt, update safety plan - Document and distribute changes in design and procedures
Information	- Inform staff about changes in saftey plan and procedures and lessons learnt - Issue and distribute safety data sheets for materials and components
Work permits	- Introduce work permits in ATEX zones, audit and control - Hot work permits and hazardous operations (welding, brazing, etc.) - Lock out, tagging and marking systems (unique equipment identifier) - Ensure all detection systems live and tested prior to start-up and/or restart operations - Equipment and line opening and clearing procedures - Work permits for confined spaces
Signaling and marking	- Clear marking of ATEX zones - Color code and nomenclature systems for equipment and piping - No smoke marking, dedicated smoke areas
Flange management, gasket size	- Having control of flanges after maintenance TA and other dismantling works is very important. - Installing the wrong gasket (size or pressure class) can lead to leakage and fire. - A flange management system where all flanges are checked in a structured way after assembly, controlling the right type of gasket in terms of size and pressure class, right length of bolts tightened correctly will minimize the risk of leaks during startup. - After each flange has been correctly checked it is recommended to have sealing on the flange to insure it has not been broken after the check
Leakage control	- Leakage control is done as a part of the startup procedure by pressuring the system first with nitrogen. - When the pressure is set for at example 7 bars a trend curve can be set in the DCS to follow any pressure decrease at a certain time. - At the same time leak spray should be used on flanges valves etc. Any noted leaks should be fixed.
Flare system	- If the unit is connected to a flare system, it is normal procedure to purge nitrogen and flammable gas into the flare system. - No air or oxygen should be purged into the flare system due to the risk of getting a flammable mix with explosion as a consequence. - If a flare system exists all safety valves containing flammable gas should be connected.
Drains	- Drains connected to flammable gas or flammable liquid should during operation be capped. This should be reviewed during the normal safety rounds in the plants.

Interdependencies and Business Interruption	
Element	Description
Redundancy	- Preferred multiple trains of operation - Consider redundant philosophy to allow further operation for bottleneck equipment (e.g. compressors)
Critical spares	- Preferred no single source equipment - Define critical spares and long lead items, consider BI losses vs. Sourcing and storage costs - Proper storage and control humidity and other factors which may affect equipment
Contingent business interruption	- Consider and mitigate loss of utilities (power, feed, etc.) - Consider and mititgate unability to take off product by clients (T&D lines, pipelines) - Consider and mititgate unability to deliver feed at site (electricity, water, hydrogen)

Annex 3: Required underwriting information

Required information

General
- Geology, Hydrology
- Plant layout
- Earthquake design standard, Restart procedures after EQ
- Technology and involved Main Contractors, References
- Scale-up operating references, scale up factor
- Lifetime of critical components vs. operating regime, equivalent operating hours calculation
- Cumulative hours, on-stream availability
- Design considerations for buildings (fire proofing, compartments, emergency exhaust systems)
- Design and installation considerations for piping, fittings, tubing, valves, gauges
- Separation from hazardous processes
- Distance of hydrogen piping and apparatus to overhead lines
- Fencing, access control
- Detection systems
- Fire Protection systems, firefighting concept
- Ignition source control standards, ATEX, Mechanical Ventilation (local and remote activation?)
- Interface to the electricity production, overhead lines/subsea cables included?
- Where is the interface to the hydrogen transport, pipeline included?
Storage & piping
- Construction standards for pressure vessels
- Safety valves design approach (main shut off, double bleed, interlock)
- Safety relief systems to avoid trapping of hydrogen and moisture/freezing of valves and safety systems
Process
- Design standards for main process equipment
- Design standard for electrical equipment
- Previous escalation steps (pilot plants, reference plants)
- Process parameters and escalation factors
- Process quality control at battery limits (e.g. water quality)
- Design measures to avoid embrittlement, erosion, and corrosion
- Monitoring of critical process parameters, safety philosophy during testing and operation
- Redundance design factor/features
Human element
- Site organization (especially in regards of safety, mgmt. of subcontractors)
- Access to site and safety training, including using of emergency equipment
- Inspection regime and operational safety (monitoring and control of leakages)
- ATEX Zones access controls
- Near-miss reporting and follow up
- Hot works procedures and administrative controls during erection and operation
- Startup / Shut down procedures
- Emergency shut down
- Emergency response plan
- Dedicated firefighting team? Cooperation with local firefighting? Distance and response plan?
Business interruption and interdependencies
- Redundancies
- Critical spares
- Interdependencies
- Fluctuating product/feedstock pricing
- Operating regime, fix vs. variable cost elements